GUJARAT ELECTRICITY REGULATORY COMMISSION

GANDHINAGAR

Draft Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026

Notification No. …. of 2026

In exercise of the powers conferred under sections 42, 61, 66, 86(1)(e) and 181 of the Electricity Act, 2003 (Act 36 of 2003) and all other powers enabling it in this behalf, and after previous publications, the Gujarat Electricity Regulatory Commission hereby makes the following Regulations for the grid interactive distributed renewable energy sources:

1. Short title and commencement

1.1. These Regulations may be called as the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026.

1.2. These Regulations shall come into force from the date of their notification in the Official Gazette.

1.3. These Regulations shall extend to the whole of the State of Gujarat.

1.4. These Regulations shall repeal the Gujarat Electricity Regulatory Commission (Net Metering Rooftop Solar PV Grid Interactive Systems) Regulations, 2016 and subsequent amendments.

2. Definitions

2.1. In these Regulations, unless the context otherwise requires,

1. **"Act**" means Electricity Act, 2003 (36 of 2003) and subsequent amendments thereof;
2. "**Agreement**" means an agreement entered into by the Distribution Licensee with the eligible consumer / prosumer / participating consumers / DRES owner / RESCO, as applicable, under these Regulations;
3. **"Area of supply**" means the geographic area within which the licensee, for the time being, is authorised by its licence to supply the electrical energy;
4. **"Bidirectional Meter**" means an energy meter which is capable of recording both import and export of electricity in the grid;
5. **"Billing Cycle or Billing Period**" means the period for which regular electricity bills are prepared for different categories of consumers by the distribution licensee, as specified by the Commission in its Regulations;
6. **BESS means Battery Energy Storage System"** or **"BESS"** shall mean electrochemical devices connected to the Power System that absorb electricity from the

grid or generation sources, store it in the form of chemical energy, and discharge it, in the form of electricity, when required. They typically include batteries, power conversion system, and battery management system;

7. "**Check Meter**" means a meter, used for accounting and billing of electricity in case of failure of Net Meter or Renewable Energy Generation Meter;
8. "**Commission"** means the Gujarat Electricity Regulatory Commission constituted under the Act;
9. "**Contracted load" / "Sanctioned Load"/ "Contracted Demand"** refers to the maximum demand in kW, kVA or HP, agreed to be supplied by the licensee and indicated in the agreement executed between the licensee and the consumer. Wherever the Agreement stipulates supply in kVA, the quantum in terms of kW may be obtained by multiplying KVA by the Power Factor of 0.9. If the Agreement stipulates supply in HP, the HP shall be converted to kW by multiplying it by 0.746;
10. **"Consumer**" means any person who is supplied with electricity for his own use by a Distribution licensee or the Government or by any other person engaged in the business of supplying electricity to the public under the Act or any other law for the time being in force and includes any person whose premises, for the time being, is connected for the purpose of receiving electricity with the works of a distribution licensee, the Government or such other person, as the case may be;
11. "**Distributed Renewable Energy System" or "DRES**" means electricity generation system based on renewable energy sources with or without BESS installed under the provisions of these Regulations and connected to the distribution network at voltage level of 33 KV and below using a distributed renewable energy source with or without energy storage having an anti-islanding protection to prevent flow of energy into the grid when grid supply is not available;
12. **"Delivery Point"** means interconnection point with distribution grid where energy generated from DRES installed is metered for the propose of determining exported or injected energy in the grid;
13. "**Electricity Supply Code**" means the GERC (Electricity Supply Code and Related Matters) Regulations, 2015 notified by the Commission under Section 50 of the Act as amended from time to time;
14. "**Eligible Consumer(s)" or "Consumer(s)"** means a consumer of electricity in the area of supply of the distribution licenses, who uses or intends to use a DRES, installed at his premises or at any other location, depending on the metering mechanism subject to

these Regulations, to meet all or part of his own electricity requirement or supply to others/ Distribution Licensee and includes a Consumer catering to a common load such as a Housing Society:

15. Provided that such DRES may be owned and/or operated by such Consumer or third party:

16. "**Financial Year**" or "Year" means the period beginning from first of April of an English calendar year and ending with the thirty first day of the March of the next year;

17. "**Generation Meter**" means an energy meter installed to measure the electricity generated by the DRES;

18. **"Group Net Metering" or "GNM**" means an arrangement whereby surplus energy generated / injected from a DRES installed by prosumer is exported to the grid through Net Meter and the exported energy is adjusted in more than one electricity service connection(s) of the same consumer having same consumer category either at the same or different premises located within the same distribution licensee's area of supply, subject to the provisions of these Regulations;

19. "**Gross Metering" or "GM**" means a mechanism whereby the total energy generated from DRES of a prosumer and the total energy consumed by a prosumer are accounted separately through appropriate metering arrangements and for the billing purpose, the total energy consumed by the prosumer is accounted at the applicable retail tariff and total energy generated by DRES is accounted for at generic tariff determined by the Commission in its tariff order for respective RE base sources for the RE capacity below threshold limit for participating in the competitive bidding and applicable from time to time;

20. **"Interconnection Point**" means the interface point of the DRES with the network of the distribution licensee;

21. **"Net Billing"** or "NB" means a single bidirectional energy meter used for net-billing at the point of supply wherein the energy imported from the Grid and energy exported into the grid from DRES of a prosumer are valued at two different tariffs, where -

    - The monetary value of the imported energy is based on the applicable retail tariff.
    - The monetary value of the exported renewable energy is based on at generic tariff determined by the Commission in its tariff order for respective RE base sources for the RE capacity below threshold limit for participating in the competitive bidding and applicable from time to time.

- The monetary value of the exported energy is deducted from the monetary value of the imported energy to arrive at the net amount to be billed by the distribution licensee.

22. "**Net Metering**" or "NM" means a mechanism whereby energy exported to the Grid from DRES of a prosumer is deducted from energy imported from the Grid in units (kWh) during the billing period subject to the provisions of these Regulations, to arrive at the net imported or net exported energy by using a single bidirectional energy meter at the point of supply and the net energy import so arrived, is billed at the applicable retail tariff as determined by the Commission or net exported energy so arrived is paid for at the Surplus Injection Rate determined by the Commission from time to time or treated as lapsed energy, as the case may be;
23. **"Obligated Entity"** means an entity for which the Commission has specified the RPO target / requirement under clause (e) of sub-section (1) of Section 86 of the Act to fulfil the renewable purchase obligation;
24. "**Participating Consumer**" means an eligible consumer whose service connection is identified for adjustment / allocation of energy generated from a DRES under Group Net Metering or Virtual Net Metering arrangement, in accordance with the allocation ratio specified in the agreement executed with the Distribution Licensee;
25. **"Premises"** means as defined under the Act and subsequent amendments thereof;
26. **"Prosumer"** means a person who consumes electricity from the grid and can also inject distributed renewable energy generated from DRES into the grid using the same network of distribution licensee**;**
27. **"Renewable Energy"** means the grid quality electricity generated from renewable energy sources including a combination of such sources;
28. **"Renewable Energy sources"** means the renewable sources or combination of such sources as recognized or approved by the Ministry of New and Renewable Energy, Government of India from time to time;
29. **"Renewable Energy Certificate"** or **"REC"** means the certificate issued in accordance with the Central Electricity Regulatory Commission (Terms & Conditions for Renewable Energy Certificates for Renewable Energy Generation) Regulations, 2022 and subsequent amendments thereof, if any;
30. **"Renewable Energy Service Company"** or **"RESCO"** means an energy service company which owns, installs and operates DRES set up under these Regulations and

supplies renewable energy under different metering mechanisms provided under these Regulations on mutually agreed terms;

31. **"Settlement Period"** means the billing period at the end of which settlement of units (KWh) generated and consumed between the distribution licensee and the prosumer takes place under Net metering, Group Net metering, Net billing and Virtual Net metering arrangement as defined in these Regulations;

32. **"Virtual Net Metering"** or **"VNM"** means an arrangement whereby the entire energy generated from a DRES is exported to the grid and recorded at the delivery point and the exported energy is adjusted in more than one electricity service connection(s) of the participating consumers belonging to the same consumer category located within the same distribution licensee's area of supply, subject to the provisions of these Regulations;

All other words and expressions used in these Regulations, although not specifically defined herein above, but defined in the Act, shall have the meaning assigned to them in the Act. The other words and expressions used herein but not specifically defined in these Regulations or in the Act but defined under any law passed by the Parliament applicable to the electricity industry in the State shall have the meaning assigned to them in such law.

Headings or Capital words are inserted for convenience and may not be taken into account for the purpose of interpretation of these Regulations. Words in the singular or plural term, as the case may be, shall also be deemed to include the plural or the singular term, respectively.

3. Scope and applicability

3.1. These Regulations would apply to DRES set up by eligible entity under different metering arrangements:

a) Net Metering ("NM") Arrangement
b) Net Billing ("NB") Arrangement
c) Group Net Metering ("GNM") Arrangement
d) Virtual Net Metering ("VNM") Arrangement
e) Gross Metering ("GM") Arrangement

4. General Conditions of Gross Metering, Net metering, Net billing, Group Net metering, and Virtual Net Metering Arrangement:

4.1. These Regulations shall be applicable to all DRES installations for which applications are received on or after the notification of these Regulations.

4.2. Gross Metering, Net Metering, Net Billing, Group Net Metering, and Virtual Net Metering Arrangement as the case may be, shall be permitted by the Distribution Licensee on a non-discriminatory manner, subject to the provisions of these Regulations.

Provided that the Inter-Connection of the DRES with the grid shall be undertaken in accordance with the standards and norms specified in the Central Electricity Authority (CEA) (Technical Standard for Connectivity of the Distributed Generation Resources) Regulations, 2013, the CEA (Measures relating to Safety and Electric Supply). Regulations, 2023, and the Gujarat Electricity Grid Code 2013 as amended from time to time, GERC Open Access Regulations, 2011, GERC Green Energy Open Access Regulations, 2024, GERC Supply Code Regulaitons, 2015 and other applicable Orders/ Regulations of the Commission, as amended from time to time.

4.3. The consumers of all categories shall be eligible to install the DRES under these Regulations under the Net Metering / Net Billing / Group Net Metering and Virtual Net Metering arrangement subject to provisions of these Regulations.

Provided that the minimum size of DRES that can be set up under Net Metering / Net Billing arrangement shall be 1 KW (AC) and maximum capacity upto 1 MW (AC) The voltage level for grid connectivity of DRES shall be aligned with the provisions for permitting voltage level of consumer connections as stated in the Gujarat Electricity Regulatory Commission (Electricity Supply Code and Related Matters) Regulations, 2015 as amended from time to time.

Provided that the eligible consumers of all categories shall be eligible to install the DRES under the Gross Metering / Virtual Net Metering Arrangement for maximum capacity up to 4000 (Four thousand) KW (AC) subject to technical feasibility at the point of injection.

Provided that the minimum size of DRES that can be installed under Gross Metering / Group Net Metering arrangement shall be 6 KW (AC).

Provided further that the minimum size of DRES that can be installed under Virtual Net Metering arrangement shall be 100 KW (AC) and shall be connected with distribution licensee network at 11 kV / 22 kV voltage level, as applicable, with delivery point at the 66 KV Sub-station of GETCO through dedicated evacuation line to be created by the DRES owner at their own cost.
The eligible consumers as well as participating consumers /connections with pending arrears with the Distribution Licensee shall not be entitled for installation of DRES under these Regulations.

Provided that the arrears in dispute and pending before the appropriate legal Forum and having granted interim relief/ stay shall not de-entitle the consumers for getting permission for installation of DRES under these Regulations.

4.4. The wheeling of energy from DRES to the participating connections in case of Group Net Metering and Virtual Net Metering arrangement shall be allowed after considering the wheeling loss in the network and on payment of applicable Open Access charges and banking charges as specified in these Regulations read with relevant Order / Regulations of the Commission.

4.5. In case of DRES, whether self-owned or owned by a RESCO, is installed on prosumer's premises under Gross Metering or Net Metering or Net Billing arrangement, as the case may be, such a prosumer shall be exempted from wheeling charges and losses.

4.6. In case DRES owned by a RESCO under Group Net Metering Arrangement / Virtual Net Metering / Net Metering Arrangement, Net Billing Arrangement, participating consumer(s) shall be subjected to the wheeling charges, wheeling losses, banking charges, if applicable, and Cross Subsidy Surcharge (CSS) and Additional Surcharge (AS) as specified in these Regulations read with relevant Order / Regulations of the Commission**.**

Provided that if participating consumers are residential consumers including common facility connection for such residential consumers and allocated capacity from DRES

owned and installed by RESCO, is upto 2 kW per residential connection; then CSS and AS will be exempted for consumption of energy from such DRES.

4.7. The RESCO / third-party owner shall enter into a separate mutual agreement with the consumer / participating consumers for payment and other commercial terms relating to supply and consumption of energy from the DRES. The Distribution Licensee shall not be a party to such commercial arrangement and shall not be responsible for recovery of dues of the RESCO from the consumer. However, for interconnection, wheeling, metering, energy accounting and billing adjustment, the RESCO / DRES owner, consumer / participating consumers and Distribution Licensee shall execute such agreement as may be approved by the Commission.

Provided also that, the dispute between the consumer and the RESCO arising out of contractual obligations under the direct agreement shall be settled mutually by them and shall not be adjudicated by the Commission or the distribution licensee. The distribution licensee shall not be the party to such dispute and shall not disconnect such consumer on the ground arising out of such dispute between consumer and the RESCO.

Provided that, where there is a dispute between the distribution licensee and the consumer, relating to any charge for electricity, such consumers shall be allowed to install DRES pending such resolution of dispute upon deposit of the disputed amount with the distribution licensee in accordance with Section 56 of the Act.

4.8. These Regulations do not preclude the right of relevant Distribution licensee or State Government Department/authorities to undertake DRES above 1 MW capacity through alternative mechanisms under Net Metering, Group Net Metering and Net Billing arrangement.

4.9. In respect of prosumer having contract demand more than 100 KW and installing DRES capacity in excess of its Contract Demand under Net Metering / Group Net Metering arrangement/ Net Billing Arrangement, such DRES capacity in excess of Contract Demand shall be allowed subject to installation of BESS facility having provisions for at least 2 hours per charging / discharging cycles per day, for at least 50% of DRES capacity which is in excess contract demand.

5. Procedure for Consumer Registration / Applications:

The eligible consumer(s)/ applicant(s) shall make an application to Distribution Licensee for installation of DRES under the provisions of these Regulations in the format approved by the Commission (Model application forms as per **Annexure-II-A, Annexure-II-B and Annexure-II-C**) along with a non-refundable fees as stipulated in the **Annexure-I** of these Regulations. All the necessary forms, formats and documents shall be enclosed with the application.

6. Technical Feasibility Analysis:

6.1. Distribution Licensee shall carry out the technical feasibility analysis based on the furnished information in the application submitted by the eligible consumers.

6.2. The applications for DRES up to 10 kW capacity, complete in all respects shall be deemed to have been accepted without requiring technical feasibility study and any commensurate enhancement of the sanctioned load of the consumer, as may be required, shall be carried out by the distribution licensee.

6.3. An internal review to check if the proposed DRES satisfies the requisite technical standards of MNRE / DISCOM / CEA /GERC, especially with respect to inverter specifications, penetration levels, safety aspects like anti-islanding and protection devices, etc. shall be undertaken.

6.4. The distribution licensee shall update distribution transformer capacity / feeder capacity available for connecting DRES under Gross Metering, Net Metering, Net Billing, Group Net Metering, Virtual Net Metering arrangement on yearly basis and shall provide the information on its website with intimation to the Commission.

Provided that recovery of cost towards strengthening of distribution network to facilitate installation of DRES for DRES system(s) above 6 KW capacity, shall be as per below stipulations:

(a) For LT consumers installing DRES above 6 kW up to 100 kW in aggregate:

(i) In respect of State owned Discoms and Torrent Power Limited: System strengthening charges for DRES capacity above 6 kW up to 100 kW shall be recovered from the Applicant by the Distribution Licensee at the rate of 25% of per kW basis charges as applicable for release of new/additional load at Low

Tension, being recovered from the applicant by the concerned Distribution Licensee as approved by the Commission from time to time.

Provided that in case of addition of DRES capacity resulting into total DRES capacity above 6 kW, the system strengthening charges shall be recovered only for additional DRES capacity.

(ii) In respect of other Discoms: In case there is any requirement of upgradation of distribution infrastructures like the augmentation of service line, distribution transformer capacity, and the like for installation of the required capacity of DRES System, the same shall be carried out by the distribution licensee, the cost of such augmentation shall be borne by the consumer.

Provided that as and when the Commission approves recovery of charges on per kW basis for release of new connection / additional load, the same shall be applicable for recovery of charges towards system strengthening for installation of DRES system.

(b) For HT consumers installing DRES System above 6 kW up to 1000 kW in aggregate:

(i) In respect of State owned Discoms: System strengthening charges for DRES capacity above 6 kW up to 1000 kW shall be recovered from the Applicant by the Distribution Licensee at the rate of 25% of per KVA basis charges as applicable for release of new/additional load at High Tension, being recovered from the applicant by the concerned Distribution Licensee as approved by the Commission from time to time.

Provided that in case of addition of DRES capacity resulting into total DRES capacity above 6 kW, the system strengthening charges shall be recovered only for additional DRES capacity.

(ii) In respect of other licensee: In case there is any requirement of up gradation of distribution infrastructures like the augmentation of service line, and the like for installation of the required capacity of DRES System, the same shall be carried

out by the distribution licensee, the cost of such augmentation shall be borne by the consumer.

Provided that as and when the Commission approves recovery of charges on per kW basis or per KVA basis for release of new connection/additional load, the same shall be applicable for recovery of charges towards system strengthening for installation of DRES system.

Provided that the cost of strengthening the distribution infrastructure, including distribution transformer, as necessary, to facilitate the installation of DRES up to a capacity of 6 kW shall be included in the annual revenue requirement of the distribution licensee.

Provided that in case of DRES set up under VNM or Gross Metering arrangement, the required evacuation infrastructure up to the delivery point shall be created by the DRES owner at its own cost.

7. Procedure for Application

7.1. The distribution licensee shall facilitate the process of setting up the DRES system. In this regard, the distribution licensee shall:

(a) Prepare separate detailed procedure and implementing guidelines for DRES projects to be implemented under Net-Metering, Group Net Metering, Net Billing, Gross Metering and Virtual Net Metering arrangement and get it approved from the Commission within 3 months from notification of these Regulations, including approval of Application formats Interconnection and Wheeling Agreement prepared in line with Model Agreement provided with these Regulations **(**Application Forms; **Annexure-II-A, Annexure-II-B and Annexure-II-C, Annexure-III –** Interconnection Agreement**; Annexure-IV –** VNM Wheeling Agreement for Captive**; Annexure-V –** VNM Wheeling Agreement for RESCO/ Third Party Mode**)** by incorporating necessary modifications in it, if any, as part of implementing procedure and guideline.

Provided that the absence of such procedure and guidelines shall not preclude the distribution licensee for implementation of provisions of these Regulations.

(b) Create a web-based portal for receiving applications from applicants for installation, interconnection and metering of DRES under these Regulations, within three months from the date of notifications of these regulations.

(c) Prepare detailed procedure and Standard Operating Procedure for implementation of software based energy accounting system covering energy settlement mechanism for DRES and submit to the Commission within 5 months from the date of notifications of these regulations for approval.

(d) Prominently display on its website and web-portal and update regularly the following; namely: -

- Detailed standardized procedure for installation and commissioning of DRES under different metering mechanism under these regulations;
- A single point of contact to facilitate the consumers in installation of DRES from submission of application form to the stage of commissioning.
- Complete list of documents required to be furnished along with such applications.
- Applicable charges to be deposited by the applicant,
- Standard Agreement for different metering arrangement as approved by the Commission as part of detailed procedure and implementing guidelines,
- Financial incentives available to the prosumers, as applicable under various schemes and programs of the Central and State Governments,
- Record of capacity of DRES system installed under different metering mechanism on the Dash Board.

7.2. Various activities and different authorities are associated with the DRES project implementation. It is necessary that the different entities carry out the works within prescribed time limit. Therefore, time frame prescribed in the table below shall be scrupulously followed by the concerned authorities.

Sr. No.	Activity	Sub Activity	Duration in day(s)
1	Registration with GEDA or agency designated by the	GEDA or Agency designated by the Government of Gujarat from time to time shall issue Registration Certificate for	5 days from receipt of duty completed application

Sr. No.	Activity	Sub Activity	Duration in day(s)
	Government of Gujarat	DRES.	
2	Approval from Chief Electrical Inspector	CEI shall approve Single Line Diagram, Earthing Diagram and Wiring Diagram for DRES	10 days from receipt of duly completed application
3	Application to Distribution Licensee	Applicant shall submit application in prescribed format along with required and documents to Distribution Licensee including capacity of DRES (BESS capacity, if applicable) to be installed, subject to provisions of these Regulations	
4	Technical Feasibility Report (TFR)	On Registration with Distribution Licensee, letter to concerned Circle / Division for TFR and informing applicant regarding specifications of CTPT, meter.	3 days from receipt of duly completed application
5	TFR from field	TFR to include following a) Name of Consumer (s) / Name of DRES Owner b) Load details of the building locations where DRES is to be installed as under: Name of Division, Sub- Division, Consumer Name, Consumer No., Address, Tariff, Contract Demand/ Load, Connected Load c) Name of 11 KV feeder, Transformer capacity, DRES capacity already connected as well as approved/sanctioned on this transformer including this proposed DRES capacity whether total DRES capacity is within the rated capacity of transformer/ feeder. d) Maximum demand recorded during last one year. e) No dues certificate. f) Estimate if any, to be recovered from applicant. Such estimate shall include details of works to be carried out for system strengthening for providing connectivity and evacuation facility of surplus power to be injected by the applicant, if estimate is not recovered based on Per KW/Per KVA charges. Provided that in case of DRES set up under Virtual Net Metering arrangement, the grid connectivity of such DRES shall be governed as per the provisions of procedure for grant of connectivity to RE	10 Days from the letter of Head Office.

Sr. No.	Activity	Sub Activity	Duration in day(s)
		based projects as approved by the Commission from time to time.	
6	Post TFR	On receipt of TFR from field, Head Office shall issue letter to applicant regarding 'In Principle' consent for connectivity, payment of connectivity charges and execution of connectivity agreement within 15 days, if required. OR Issue estimate subject to these Regulations, to Applicant for system strengthening to be paid within 30 days, payment of connectivity charges and execution of connectivity agreement, if required.	2 days from receipt of TFR from field office
7	Signing of connectivity agreement and issuance of letter to applicant for completion of project work	Case 1 (No system strengthening required) On payment of Connectivity Charges and execution of Connectivity Agreement within 15 days of consent. Letter to applicant to complete the project work within 6 months	5 days from execution of agreement
		Case 2 (If system strengthening required) On payment of Connectivity Charges and execution of Connectivity Agreement within 30 days along with payment of estimate, if any. Letter to applicant to complete the project work within 6 months. Provided that in case of DRES set up under Virtual Net Metering arrangement, the grid connecting DRES shall be governed as per the provisions of procedure for grant of connectivity to RE based projects.	5 days from execution of agreement
8	System strengthening by Distribution Licensee	Distribution Licensee to complete the work of system strengthening.	15 days from date of payment of connectivity charges and execution of connectivity agreement.
9	Notice to Applicant for commissioning	Issuance of two months' notice to applicant for commissioning of the project on expiry of 6 months project completion period.	Within 5 days on expiry of 6 months
10	In case of non-completion of work by applicant	If no intimation received from Applicant on expiry of 2 months' notice period, application shall be cancelled informing the applicant within 30 days forfeiting all charges paid for DRES.	Within 5 days on expiry of 2 months

Sr. No.	Activity	Sub Activity	Duration in day(s)
11	On completion of work by Applicant	1. Intimation to Applicant to submit following documents within 3 days: (if not submitted along with intimation of commissioning by applicant) 2. Ownership of DRES 3. Installation charging approval of Chief Electrical Inspector (CEI) 4. Meter/CTPT testing certificate from NABL Accredited Lab. 5. All equipment should comply with IEC standards. Applicant to submit relevant IEC certificate/test reports for all equipment's i.e. for Plants & Machinaries / inverters/ cables/ junction box/ Transformer /RMU/CTPT/meter etc. 6. Installation of proper protection system (inverter shall have anti islanding feature) along with second line of protection such as no volt relay, (for DRES above 10 Kw), applicant has to pay connectivity charges and execute connectivity agreement with Distribution Licensee. **Note:** If Applicant is not submitting above documents within 3 days, application shall be cancelled forfeiting all charges paid for DRES.	3 days from receipt of completion letter from applicant
12	Intimation to Field Office	Upon receipt of documents from the Applicant, intimation to Field Office/Sub-division for installation of meter (Generation meter to record total generation and bidirectional/ABT meter for net metering).	2 days from receipt of documents from the applicant
13	Report from field/sub-division	Installation of meter (Generation meter to record total generation and bidirectional/ABT meter for net metering) and intimate to applicant and report to HO	5 days from receipt of letter from HO
14	Intimation to GEDA or agency designated by the Government of Gujarat	Distribution Licensee shall intimate to GEDA or agency designated by the Government of Gujarat for issuing commissioning certificate	2 days from receipt of letter from Distribution Licensee
15	Issuance of Commissioning Certificate from GEDA or agency designated by the Government of	GEDA or agency designated by the Government of Gujarat shall visit the site in consultation with Distribution Licensee and applicant and issue Commissioning Certificate	3 days from the receipt of intimation from applicant

Sr. No.	Activity	Sub Activity	Duration in day(s)
	Gujarat		

Provided that the application for DRES upto 10 kW capacity, complete in all respect shall be deemed to have been accepted without requiring technical feasibility study and any commensurate enhancement of the sanction load of the consumer, as may be required, shall be carried out by the Distribution Licensee.

Provided that there shall not be requirement for execution of separate written connectivity agreement between the Distribution Licensee and the Consumer in case of DRES installed under PM Surya Ghar Muft Bijli Yojana and the Consumer shall be deemed to be bound by terms and conditions of these Regulations in respect of DRES. In such case, the date of commencement of Agreement shall be the date of commissioning of DRES and in lieu of execution of formal connectivity agreement, the concerned Discom shall communicate to the Applicant, under proper receipt, mentioning the date of commencement of agreement along with the applicable rate of purchase of surplus energy."

Provided further that in case of any delay on the part of distribution licensee without any just cause, the Licensee shall be liable to pay compensation to the consumer at a rate which shall not be less than five hundred rupees per day for each day of default

8. Eligibility Conditions, Metering Mechanisms and allowed capacities

8.1. The Eligible Consumer for the DRES availing Gross Metering, Net Metering, Net Billing, Group Net Metering, Virtual Net Metering facility shall:

(I) Consumer /Prosumer level eligibility

The Eligible Consumer / Prosumer / Participating Consumer, as the case may be, shall satisfy the following conditions:

a) The applicant shall be consumer of the concerned Distribution Licensee within whose area of supply the DRES is proposed to be installed or whose service connection is proposed to receive adjustment / allocation of energy from such DRES.

b) The consumer shall not have any pending arrears with the Distribution Licensee:

Provided that arrears which are under dispute before the appropriate legal forum and in respect of which interim relief / stay has been granted shall not debar the consumer from applying under these Regulations.

c) The consumer shall be eligible for anyone metering arrangement only provided under these Regulations for the same service connection, namely Net Metering, Net Billing, Gross Metering, Group Net Metering or Virtual Net Metering, as the case may be.

d) The consumer shall comply with the applicable provisions of the Electricity Act, 2003, the Electricity Rules, 2005, the GERC Supply Code, the GERC Green Energy Open Access Regulations, 2024, these Regulations and other applicable Regulations / Orders of the Commission.

e) Where exemption from Cross Subsidy Surcharge and Additional Surcharge is claimed on the ground of captive consumption, the consumer / participating consumers shall satisfy the requirements of captive generating plant and captive user under the Electricity Rules, 2005 and applicable Regulations / Orders of the Commission.

f) The minimum and maximum DRES capacity to be installed at any Eligible Consumer's premises under various metering arrangement shall be within the limits as specified in these Regulations.

Provided also that the grid connectivity voltage and installed capacity of DRES shall be aligned with the provisions for permitting consumer connections as stated in the GERC (Electricity Supply Code and Related Matters) Regulations, 2015 as amended from time to time, read with the provisions of GERC (Terms and Conditions for Green Energy Open Access Regulations), 2024 as amended from time to time.

(II) DRES owner-level eligibility

The owner of the DRES, whether the consumer himself, group of consumers, RESCO, third-party owner or any other eligible entity, shall satisfy the following conditions:

a) The DRES owner shall own, lease or be in lawful possession of the premises, rooftop, terrace, building, infrastructure, open land or other location where the DRES is proposed to be installed, or shall otherwise have valid legal authority to install and operate the DRES at such location.

b) The DRES shall be based on renewable energy sources recognised or approved by MNRE / Government of India / Government of Gujarat and shall comply with the

technical and safety standards specified by CEA, GERC, Distribution Licensee, GETCO, SLDC, GEDA and other competent authorities.

c) The DRES owner shall obtain registration from GEDA / agency designated by the Government of Gujarat and all other approvals, clearances, connectivity permissions, CEI approvals, commissioning certificate and metering approvals as may be required under applicable laws.

d) The DRES owner shall be responsible for safe operation, maintenance and rectification of defects of the DRES up to the interconnection point / delivery point, as applicable.

e) The DRES shall be installed within the capacity limits, voltage level and technical feasibility conditions specified under these Regulations and the procedure approved by the Commission.

8.2. **Net Metering Arrangement**

Consumers of all categories shall be eligible to establish DRES under Net Metering Arrangement.

The minimum size of DRES that can be set up under Net Metering arrangement shall be 1 kW (AC), while the maximum size shall be limited to 1000 KW (AC).

Provided that the prosumer /consumer having contract demand of above 100 KW and installing DRES capacity in excess of contract demand, such DRES capacity shall be permitted only if such DRES include BESS having provisions for at least 2 hours per charging / discharging cycles per day, for at least 50% of DRES capacity which is in excess of contract demand.

Prosumer / Consumers can also switch from existing Net Metering arrangement to Gross Metering or Net Billing arrangement maximum three times during life of the DRES project or as decided by the Commission. Further, such switch over can be allowed only once in a financial year with advance intimation of 30 days before commencement of the financial year.

8.3. **Net Billing Arrangement**

Consumers of all categories shall be eligible to establish DRES under Net Billing arrangement.

The minimum size of DRES that can be set up under Net Billing arrangement shall be 1 kW (AC), while the maximum size shall be limited to 1000 KW (AC).

Provided that the prosumer /consumer having contract demand of above 100 KW and installing DRES capacity in excess of contract demand, such DRES capacity shall be permitted only if such DRES include BESS having provisions for at least 2 hours per charging / discharging cycles per day, for at least 50% of DRES capacity which is in excess of contract demand.

Prosumer / Consumer can also switch from existing Net Billing arrangement to Net Metering or Gross Metering arrangement maximum three times during life of the DRES project or as decided by the Commission. Further, such switch over can be allowed only once in a financial year with advance intimation of 30 days before commencement of the financial year.

8.4. **Gross Metering Arrangement**

Prosumer / Consumer of all categories shall be allowed to install DRES under Gross Metering arrangement.

The minimum size of DRES that can be set up under Gross Metering arrangement shall be 1 kW(AC) and maximum size shall be limited to 4000 kW (AC).

8.5. **Group Net Metering Arrangement**

Prosumer / Consumer of all categories shall be allowed to install DRES under Group Net Metering arrangement.

Provided that service connection(s) of prosumer / consumer installing DRES under Group Net Metering arrangement shall have same name, same tariff category and located in the supply area of the same distribution licensee.

The minimum size of DRES that can be set up under group net metering mechanism shall be 6 kW, while the maximum size shall be limited to 1000 KW (AC).

Provided that the prosumer / consumer having contract demand of above 100 KW and installing DRES capacity in excess of contract demand, such DRES capacity shall be permitted only if such DRES include BESS having provisions for at least 2 hours per

charging / discharging cycles per day, for at least 50% of DRES capacity which is in excess of contract demand.

8.6. **Virtual Net Metering Arrangement**

Consumers of all categories shall be allowed to install DRES under Virtual Net Metering arrangement within the supply area of same distribution licensee.

The Participating Consumers shall be consumers of the same Distribution Licensee and shall belong to the same tariff category. The DRES may be installed at a location different from the premises of the Participating Consumers, subject to the DRES owner having lawful possession / right to use such location.

The minimum aggregate capacity of DRES shall be 100 kW (AC) and the maximum aggregate capacity shall not exceed 4000 kW (AC), subject to technical feasibility and other provisions of these Regulations.

The DRES shall be connected with the distribution licensee network at 11 kV / 22 kV voltage level, as applicable, with delivery point at the 66 kV sub-station of GETCO through dedicated evacuation line to be created by the DRES owner at its own cost.

The allocation ratio of energy among Participating Consumers shall be specified in the agreement executed with the Distribution Licensee and shall be used for energy accounting and billing adjustment.

The Participating Consumers shall nominate one Lead / Nodal Consumer for communication, submission of documents, coordination with the Distribution Licensee and receipt of notices, without prejudice to the individual obligations of each Participating Consumer.

Provided that except residential category of consumers, in case the DRES capacity is in excess of aggregate contract demand of all participating consumers, the same shall be allowed only if such DRES include BESS having provisions for at least 2 hours per charging / discharging cycles per day, for at least 50% of DRES capacity which is in excess of aggregate contract demand.

8.7. The summary of the DRES capacity and eligible consumer categories that are permissible under different metering mechanism subject to the provisions of these regulations, is shown in the table below:

Metering Mechanism	**Capacity that can be availed**		**Eligible consumer categories**
	Minimum	**Maximum**	
Net Metering	1 KW	1000 KW	All Consumer Categories
Net Billing	1 KW	1000 KW	All Consumer Categories
Gross Metering	1 KW	4000 KW	All Consumer Categories
Group Net Metering	6 KW	1000 KW	All Consumer Categories (having same name, same tariff category and located in supply area of same distribution license area)
Virtual Net Metering	100 KW	4000 KW	All Consumer Categories (having same tariff category located in supply area of same distribution license)

9. Energy Accounting and commercial settlement mechanism

Energy injected prior to commissioning of DRES shall be deemed as inadvertent /lapsed energy. The prosumer / DRES owner is not eligible to receive any monetary compensation for such inadvertent power.

9.1. **Net Metering**

9.1.1. The prosumer may set up DRES to offset prosumer's electricity consumption from the distribution licensee.

9.1.2. The distribution licensee shall undertake meter reading of all DRES according to the regular billing cycle.

9.1.3. The distribution licensee shall record readings of bi-directional meter and generation meter.

9.1.4. For each billing period, the distribution licensee shall make the following additional information available on its bill to consumer:

(a) DRES generation recorded in the generation meter.

(b) Electricity exported / injected by DRES in the grid in the billing period.

(c) Electricity imported by prosumer from the grid in the billing period.

(d) Net billed electricity, for which a payment is to be made by the prosumer, if any or net surplus injection in the grid during billing period, subject to provisions of these Regulations.

(e) Direct consumption from DRES by prosumer during billing period.

(f) DRES generation used by distribution licensee for RPO compliance, if applicable.

9.1.5. The electricity exported or injected into the grid from the Distributed Renewable Energy System (DRES), as recorded during a billing period, shall be adjusted against the electricity drawn or imported from the grid during the same billing cycle:

Provided that in case of prosumer other than residential category, such adjustment shall be allowed upto thirty percent (30%) of the total energy drawn or imported by the prosumer from the Distribution Licensee during the relevant billing period subject to payment of applicable banking charges as specified under the GERC Green Energy Open Access Regulations, as amended from time to time. Any excess energy exported or injected beyond the permissible limit specified above shall not be eligible for adjustment and shall be treated as lapsed energy.

Provided further that in case of a prosumer in the residential category, the entire energy exported or injected into the grid during a billing cycle shall be eligible for

adjustment against the electricity drawn or imported from the grid during the same billing cycle, without levy of banking charges:

Provided also that any surplus energy remaining after such adjustment for residential category prosumers shall be treated as deemed purchase by the concerned Distribution Licensee at the rate of Rs. 2.25 per kWh, or such rate as may be specified by the Commission from time to time.

9.1.6. In case of net drawl of electricity by prosumer from the distribution licensee during any billing period after providing adjustment of exported /injected energy in terms of above, the distribution licensee shall raise a bill as per applicable retail tariff for such net electricity consumption.

9.1.7. In case the prosumer is under the ambit of time-of-day (ToD) tariff, as decided by the Commission from time to time, the following process shall be followed:

(a) Exported or injected energy in the grid from DRES in the off-peak hours during the billing cycle shall be eligible to off-set / adjust against consumption from Grid during off-peak hours only, subject to 9.1.5 above.

(b) Exported or injected energy in the grid from DRES in the peak hours during the billing cycle shall be eligible to off-set against consumption from Grid during peak as well as off-peak hours during the billing cycle, subject to 9.1.5 above.

9.1.8. The exported or injected electricity measured in kilowatt hour (kWh) shall only be utilized to offset the consumption measured in kWh and shall not be utilized to compensate any other fee and charges levied by the distribution licensee.

9.1.9. Regardless of availability of excess electricity with the prosumer during any billing period, the consumer will continue to pay all other charges such as fixed / demand charges, government levy etc, as applicable.

9.1.10. The distribution licensee shall continue the arrangement as per the useful life of the DRES unless the prosumer ceases to be a consumer of the licensee or DRES is abandoned earlier or opt for change in the option.

9.2. **Net Billing**

9.2.1. The prosumer may set up DRES to offset prosumer's electricity bill from the distribution licensee.

9.2.2. The distribution licensee shall undertake meter readings of bidirectional meter and generation meter, according to the regular billing cycle.

9.2.3. For each billing period, the distribution licensee shall make the following additional information available on its bill to the prosumer:

(a) DRES generation recorded in the generation meter.
(b) Electricity exported / injected by DRES in the grid in the billing period.
(c) Electricity imported / drawn by prosumer from the grid in the billing period.
(d) Direct consumption from DRES by prosumer during billing period.
(e) DRES generation used by distribution licensee for RPO compliance, if applicable.

9.2.4. The energy generated by the DRES may be first used for self-consumption and surplus energy injected into the Grid and / or Energy drawn from the Grid shall be billed as per following equation:

Energy Bill of consumer =

Fixed Charges + Other applicable charges and levies + (EDL × TRST) - (ERE × TRR) ; Where:

(a) Fixed Charges mean the Fixed/Demand Charges as applicable to the consumer category as per the applicable retail supply Tariff Order.
(b) Other applicable charges and levies mean electricity duty, fuel and power purchase price adjustment surcharge etc.
(c) EDL means the Energy Drawn from the Grid by the prosumer.
(d) TRST means the applicable Retail Supply Tariff of the concerned consumer category as per the applicable retail supply Tariff Order of the Commission.
(e) ERE means the energy exported / injected by DRES in the grid in the billing period
(f) TRR means generic tariff determined by Commission from time to time in its tariff order for respective RE base sources for the RE capacity below threshold limit for participating in the competitive bidding and applicable from time to time.

9.2.5. The monetary value of the imported energy is debited based on the applicable retail tariff determined by the Commission from time to time. The monetary value of the exported / injected energy is credited based on the generic tariff determined by the Commission and as applicable as on date of DRES is commissioned and shall be applicable for whole life of the DRES; e.g. for the DRES commissioned during 2024-25, the tariff determined by the Commission and applicable for FY 2024-25 shall be applicable. The monetary value of the exported / injected energy is deducted from the monetary value of imported energy to arrive at the net amount to be billed.

9.2.6. The distribution licensee shall continue the arrangement as per the useful life of the DRES unless the prosumer ceases to be a consumer of the licensee or DRES is abandoned earlier or opt for change in the option.

9.3. Gross Metering

9.3.1. Gross metering is permitted for prosumer who opts to sell the entire energy generated by DRES to the distribution licensee by injecting the entire generation into the distribution grid.

9.3.2. The distribution licensee shall undertake meter reading of the Generation meter as per regular billing cycle.

9.3.3. For each billing period, the distribution licensee shall make the following additional information available on its bill to the prosumer:

(a) Quantum of DRES generation recorded in the Generation Meter in the billing period;
(b) Quantum of gross DRES energy injection in the grid during billing period;
(c) Quantum of electricity units consumed by the prosumer from the grid in the billing period;
(d) Amount payable to the distribution licensee towards electricity units consumed by prosumer, if any.
(e) Renewable Energy generation units used by the Distribution Licensee for RPO compliance.

9.3.4. The applicable tariff for gross energy supplied from the DRES will be generic tariff determined by Commission in its tariff order for respective RE base sources for the RE capacity below threshold limit for participating in the competitive bidding and applicable from time to time.

9.3.5. This shall be adjusted against the total billing amount for consumption of energy by the prosumer from the distribution licensee in billing cycle.

9.3.6. In case the monetary value of energy exported from DRES exceeds the monetary value of energy consumption from the distribution licensee during any billing cycle, such an excess amount shall be carry forward as credit in next billing cycle.

9.3.7. The injection / export of energy from DRES to the grid shall be subject to scheduling as per the GERC (Forecasting, Scheduling, Deviation settlement Mechanism and related matters of Wind and Solar Generating Stations) Regulations, 2019 as amended from time to time and relevant Orders of the Commission on different renewable energy based (Green Energy) projects.

9.4. Group Net Metering

9.4.1. The distribution licensee shall undertake the meter reading of the bidirectional meter of the prosumer where the DRES is located and the consumer meters of all participating connections as per regular billing cycle.

9.4.2. For each billing period, the distribution licensee shall make the following additional information available on its bill to the prosumer and participating consumers:

(a) Quantum of DRES generation recorded in the Generation Meter in the billing period;
(b) Quantum of electricity injected by DRES in the grid in the billing period.
(c) Quantum of electricity consumed by prosumer from DRES directly;
(d) Quantum of electricity adjusted out of total energy injected by the DRES in each participating connection's bill during the billing period .
(e) Quantum of electricity supplied by the distribution licensee in the billing period to the prosumer and each of the participating connections.

(f) Quantum of net billed electricity in prosumer and each participating connection's bill.

(g) Renewable Energy generation units used by the Distribution Licensee for RPO compliance.

9.4.3. The energy exported or injected into the grid from the Distributed Renewable Energy System (DRES) under the Group Net Metering arrangement shall be allocated to the participating consumers in accordance with the allocation ratio specified in the agreement executed with the Distribution Licensee, for the purpose of offsetting their electricity consumption during the relevant billing period.

9.4.4. The energy exported or injected from the DRES during any billing period and made available at the consumption end after accounting for applicable losses shall be adjusted against the energy drawn from the grid by the participating consumers, in accordance with the allocation ratio specified in the agreement with the Distribution Licensee, on a 15-minute time block basis. The difference between the energy injected from the DRES (as available at the consumption point) and the energy consumed by the participating consumers in the corresponding 15-minute time block shall be treated as banked energy.

(a) In case of participating consumers other than in the residential category, credit of such banked energy shall be allowed up to a maximum of thirty percent (30%) of the total energy drawn by the participating consumers from the Distribution Licensee during the relevant billing period, subject to payment of applicable banking charges as specified under the GERC Green Energy Open Access Regulations, as amended from time to time:

Provided that such banked energy shall be adjusted within the same billing cycle and shall not be permitted to be carried forward to subsequent billing cycles:

Provided further that any unutilized banked energy remaining at the end of the billing cycle shall be treated as lapsed energy.

(b) In case of participating consumers in the residential category, the energy exported / injected from the DRES and available at the consumption end, as

per the allocation ratio specified in the agreement with the Distribution Licensee, shall be adjusted against the energy drawn from the grid during the same billing cycle, without levy of banking charges:

Provided that any surplus energy remaining after such adjustment shall be treated as deemed purchase by the concerned Distribution Licensee at the rate of Rs. 2.25 per kWh, or at such rate as may be specified by the Commission from time to time.

9.4.5. In case the participant consumers are in the ambit of ToD tariff,

(i) the banked energy, if any, available during peak period specified in the Tariff Orders of the Commission for respective distribution licensees from time to time shall be allowed to be utilized during the peak period and the off-peak period, subject to 9.4.4 above

(ii) In case of the banked energy available during off-peak period (i.e. period other than the peak period) shall be utilized only during off-peak period, subject to 9.4.4 above

9.4.6. In case of net drawl of electricity by participating consumers from the distribution licensee during any billing period after providing adjustment of exported /injected energy in terms of above, the distribution licensee shall raise a bill as per applicable retail tariff for such net electricity consumption.

9.4.7. Where the service connection of any participating consumer(s) is disconnected due to any reason under any law for the time being in force, the unadjusted units/remaining credits of that consumer shall be treated as lapsed units except the residential category of consumers.

9.4.8. Change in allocation ratio once in a financial year shall be permitted subject to intimation one month prior to commencement of the financial year and will be effective from beginning of the financial year.

9.5. Virtual Net Metering

9.5.1. The Distribution Licensee shall undertake meter reading of energy injected /exported from DRES at the delivery point and consumer meters of all participating Consumers according to the regular billing period concurrently.

9.5.2. For each billing period, the distribution licensee shall make the following information available on its bill to all consumers :

(a) Quantum of electricity exported / injected by DRES in the grid and measured at the delivery point in the billing period,

(b) Quantum of electricity allocated to each participating consumers out of total electricity exported / injected by the DRES in the grid during the billing period as per the allocation ratio specified in the Agreement with distribution Licensee,

(c) Quantum of electricity supplied by the Distribution Licensee in the billing period, to the participating consumers

(d) Quantum of Net billed electricity, for which a payment is to be made by the participating consumers, if any or net surplus injection in the grid during billing period subject to provisions of these Regulations.

(e) Renewable Energy generation units used by the Distribution Licensee for RPO compliance.

9.5.3. The energy exported or injected into the grid from the Distributed Renewable Energy System (DRES) under the Virtual Net Metering arrangement shall be allocated to the participating consumers in accordance with the allocation ratio specified in the agreement executed with the Distribution Licensee, for the purpose of offsetting their electricity consumption during the relevant billing period.

9.5.4. The energy exported or injected from the DRES in the grid during any billing period and made available at the consumption end after accounting for applicable losses shall be adjusted against the energy drawn from the grid by the participating consumers, in accordance with the allocation ratio specified in the agreement with the Distribution Licensee, on a 15-minute time block basis. The difference between the energy injected from the DRES (as available at the consumption point) and the energy consumed by the participating consumers in the corresponding 15-minute time block shall be treated as banked energy.

(a) In case of participating consumers other than in the residential category, credit of such banked energy shall be allowed up to a maximum of thirty percent (30%) of the total energy drawn by the participating consumers from the Distribution Licensee during the relevant billing period, subject to payment of

applicable banking charges as specified under the GERC Green Energy Open Access Regulations, as amended from time to time:

Provided that such banked energy shall be adjusted within the same billing cycle and shall not be permitted to be carried forward to subsequent billing cycles:

Provided further that any unutilized banked energy remaining at the end of the billing cycle shall be treated as lapsed energy.

(b) In case of participating consumers in the residential category, the energy injected from the DRES and available at the consumption end, as per the allocation ratio specified in the agreement with the Distribution Licensee, shall be adjusted against the energy drawn from the grid during the same billing cycle, without levy of banking charges:

Provided that any surplus energy remaining after such adjustment shall be treated as deemed purchase by the concerned Distribution Licensee at the rate of Rs. 2.25 per kWh, or at such rate as may be specified by the Commission from time to time.

9.5.5. In case of net drawl of electricity by participating consumers from the distribution licensee during any billing period after providing adjustment of exported /injected energy in terms of above, the distribution licensee shall raise a bill as per applicable retail tariff for such net electricity consumption.

9.5.6. In case the participant consumers are in the ambit of ToD tariff,

(i) the banked energy, if any, available during peak period period specified in the Tariff Orders of the Commission for respective distribution licensees from time to time shall be allowed to be utilized during the peak period and the off-peak period, subject to 9.5.4 above.

(ii) In case of the banked energy available during off-peak period (i.e. period other than the peak period) shall be utilized only during off-peak period, subject to 9.5.4 above.

9.5.7. The injection of energy from DRES to the grid shall be subject to scheduling as per the GERC (Forecasting, Scheduling, Deviation settlement Mechanism and related matters of Wind and Solar Generating Stations) Regulations, 2019 as amended from time to time and relevant Orders of the Commission on different renewable energy based (Green Energy) projects.

9.5.8. Where the service connection of any participating consumer(s) is disconnected due to any reason under any law for the time being in force, the unadjusted units/remaining credits of that consumer shall be treated as lapsed units except the residential category of consumers.

9.5.9. Change in allocation ratio once in a financial year shall be permitted subject to intimation one month prior to commencement of the financial year and will be effective from beginning of the financial year.

10. Open Access charges

10.1. Net Metering Arrangement

In case a self-owned DRES or owned by RESCO, is installed on prosumer premises under Net Metering arrangement, the banking charges at the rate as decided by the Order / Regulation of the Commission, shall be levied on the quantum of DRES energy exported / injected into the grid, is off-set against the consumption from grid during the billing cycle. Provided that banking charges shall not be levied in case the participating prosumer and service connection under Net metering arrangement belongs to residential (RGP) category of consumer.

Where exemption from CSS and AS is claimed on the ground of captive consumption, the consumer / participating consumers shall fulfil captive generating plant and captive user criteria, the prosumer / consumer have to fulfil the qualification criteria for Captive power plant as specified in Electricity Rules 2005 and GERC (Green Energy Open Access) Regulations 2024 as amended from time to time.

Provided that in case DRES do not qualify criteria for captive plant and captive user, Cross Subsidy Surcharge and Additional Surcharge shall be levied for consumption of

energy from such DRES. In case consumer consuming energy from such DRES does not claim RE attribute of energy and allow DISCOM to avail the same for RPO compliance, such consumer shall be allowed to claim 25% concession in the Cross Subsidy Surcharge and Additional Surcharge or as decided by the Commission in the relevant Tariff Order for different RE sources from time to time.

Provided also that the Cross Subsidy Surcharge and Additional Surcharge shall be exempted for consumption of energy by residential consumers from non-captive DRES, if the DRES capacity set up under RESCO mode is not exceeding 2kW (AC).

10.2. **Net Billing Arrangement**

The prosumer / consumer have to fulfil the qualification criteria for Captive power plant as specified in Electricity Rules 2005 and GERC (Green Energy Open Access) Regulations 2024 as amended from time to time.

Provided that in case DRES do not qualify criteria for captive plant and captive user, Cross Subsidy Surcharge and Additional Surcharge shall be levied for consumption of energy from such DRES. In case consumer consuming energy from such DRES does not claim RE attribute of energy and allow DISCOM to avail the same for RPO compliance, such consumer shall be allowed to claim concession in the Cross Subsidy Surcharge and Additional Surcharge or as decided by the Commission in the relevant Tariff Order for different RE sources from time to time.

Provided also that the Cross Subsidy Surcharge and Additional Surcharge shall be exempted for consumption of energy by residential consumers from non-captive DRES, if the DRES capacity set up under RESCO mode is not exceeding 2kW (AC).

10.3. **Group Net Metering Arrangement**

In case a self owned DRES or owned by RESCO is installed on prosumer premises under Group Net Metering arrangement, the participating connection(s) shall be subjected to the wheeling charges, wheeling losses, and banking charges as per GERC (Green Energy Open Access) Regulations 2024 and the RE technology wise tariff orders (Wind, Solar etc) notified by the Commission from time to time.

The banking charges at the rate as decided by the Order / Regulation of the Commission, shall be levied on the quantum of banked energy off-set against the consumption of participant consumers from grid during the billing cycle. Provided that banking charges shall not be levied in case the participating consumers and service connection under Group Net Metering arrangement belongs to residential (RGP) category of consumer.

The participating connection(s) have to fulfil the qualification criteria for Captive power plant as specified in Electricity Rules 2005 and GERC (Green Energy Open Access) Regulations 2024 as amended from time to time.

Provided that in case DRES do not qualify the criteria for captive plant and captive user, Cross Subsidy Surcharge and Additional Surcharge shall be levied for consumption of energy from such DRES. Incase consumer consuming energy from such DRES does not claim RE attribute of energy and allow DISCOM to avail the same for RPO compliance, such consumer shall be allowed to claim 25% concession in the Cross Subsidy Surcharge and Additional Surcharge or as decided by the Commission in the relevant Tariff Order for different RE sources from time to time.

Provided also that the Cross Subsidy Surcharge and Additional Surcharge shall be exempted for consumption of energy by residential consumers from non-captive DRES, if the DRES capacity set up under RESCO mode is not exceeding aggregate capacity worked out with consideration of upto 2 kW per participant residential consumers and prosumer.

10.4. **Virtual Net Metering Arrangement**

In case a self owned or RESCO owned DRES is installed under Virtual Net Metering arrangement, the participating consumers shall be subjected to the wheeling charges, wheeling losses and banking charges as per GERC (Green Energy Open Access) Regulations 2024 and the RE technology wise tariff orders (Wind, Solar etc) notified by the Commission from time to time

Provided that the banking charges at the rate as decided by the Order / Regulation of the Commission, shall be levied on the quantum of banked energy off-set against the consumption from grid during the billing cycle. Provided that banking charges shall

not be levied in case the participating consumers under Virtual net metering arrangement belongs to residential (RGP) category of consumer.

The participating connection(s) have to fulfil the qualification criteria for Captive power plant as specified in Electricity Rules 2005 and GERC (Green Energy Open Access) Regulations 2024 as amended from time to time.

Provided that in case DRES do not qualify the criteria for captive plant and captive user, Cross Subsidy Surcharge and Additional Surcharge shall be levied for consumption of energy from such DRES. Incase consumer consuming energy from such DRES does not claim RE attribute of energy and allow DISCOM to avail the same for RPO compliance, such consumer shall be allowed to claim 25% concession in the Cross Subsidy Surcharge and Additional Surcharge or as decided by the Commission in the relevant Tariff Order for different RE sources from time to time.

Provided also that the Cross Subsidy Surcharge and Additional Surcharge shall be exempted for consumption of energy by residential consumers from non-captive DRES, if the DRES capacity set up under RESCO mode is not exceeding aggregate capacity worked out with consideration of upto 2 kW per participant residential consumers.

11. Interconnection with the Grid: Standards and Safety

11.1. Consumer intending to install DRES shall apply for connectivity of DRES with the grid in accordance with the Procedure for Grant of Connectivity to Projects based on Renewable Energy Sources to Intra-State Transmission/ Distribution System, as amended from time to time and provisions of these Regulations.

11.2. The Distribution Licensee shall ensure that the inter-connection of the DRES with its Network conforms to the specifications, standards and other provisions specified in the CEA (Technical Standard for Connectivity of the Distributed Generation Resources) Regulations, 2013, the CEA (Measures relating to Safety and Electric Supply), Regulations, 2023, as amended from time to time and Orders/ Regulations of the Commission as amended from time to time.

Provided that a variation in the rated capacity of the system within a range of five percent (5%) shall be allowed;

Provided further that the DRES shall qualify the technical requirements for grid interconnection with the network of the distribution licensee as specified under the applicable CEA Regulations and Regulations / Order notified by the Commission.

11.3. The voltage level for interconnection with the grid shall be governed as per provisions under the GERC (Electricity Supply Code and Related Matters) Regulations, 2015 as amended from time to time.

11.4. In case of DRES set up under Net Metering, Net Billing or Group Net Metering arrangement, where the DRES is installed at the premises of the Prosumer / Consumer and is connected with the distribution system through the consumer service connection / bidirectional meter, the Prosumer / Consumer / DRES Owner shall be responsible for the design, installation, operation, maintenance, safety and rectification of defects of the DRES and all associated equipment up to the prosumer side of the bidirectional meter or such interconnection point as may be specified by the Distribution Licensee in accordance with these Regulations and the approved procedure. Such responsibility shall include, inter alia, the renewable energy generating system, inverter / power conditioning unit, BESS, if any, internal wiring, protection system, isolating device, earthing arrangement, generation meter, check meter, communication facility and all other equipment forming part of the DRES up to the aforesaid point. The Distribution Licensee shall be responsible for safe operation, maintenance and rectification of defects of the distribution system beyond the bidirectional meter / interconnection point, subject to the condition that any damage, disturbance or adverse impact caused to the distribution system due to defective, unsafe or non-compliant operation of the DRES shall be rectified at the cost and responsibility of the Prosumer / Consumer / DRES Owner. In case of Group Net Metering arrangement, the aforesaid responsibility shall apply to the DRES installed at the premises of the Prosumer and connected to the distribution system. The other participating service connection(s) shall continue to be governed by the applicable Supply Code, tariff orders and consumer-level obligations in respect of their respective installations and consumption.

11.5. In case of DRES set up under Gross Metering or Virtual Net Metering arrangement, where the entire energy generated from the DRES is injected into the grid and recorded at the delivery point / interconnection point, the DRES Owner, whether being the Consumer / group of Consumers / RESCO / third-party owner, shall be responsible for the design, installation, operation, maintenance, safety and rectification of defects of the DRES and associated evacuation infrastructure up to the delivery point / interconnection point, as specified by the Distribution Licensee / GETCO / SLDC / competent authority in accordance with these Regulations and the approved connectivity procedure. Such responsibility shall include, inter alia, the generating plant, inverter / power conditioning unit, BESS, if any, transformer, RMU / switchgear, protection system, earthing system, dedicated evacuation line, CT/PT units, meters, check meters, communication facility, RTU / remote monitoring facility, isolating arrangements and all other equipment forming part of the DRES and its evacuation system up to the delivery point / interconnection point. The Distribution Licensee shall be responsible for safe operation, maintenance and rectification of defects of its network beyond the delivery point / interconnection point, subject to the condition that any damage, disturbance or adverse impact caused to such network due to defective, unsafe or non-compliant operation of the DRES or its evacuation system shall be rectified at the cost and responsibility of the DRES Owner.

11.6. The DRES Owner shall be responsible for safe operation, maintenance and rectification of any defect of the DRES up to the delivery point.

11.7. The prosumer / DRES shall be solely responsible for any accident to human being / animals whatsoever (fatal/non- fatal/departmental/non-departmental) that may occur due to back feeding from the DRES when the grid supply is off, based on the issue decided by the Chief Electrical Inspector.

11.8. The distribution licensee reserves the right to disconnect the consumer's installation / DRES at any time in the event of such exigencies to prevent accident or damage to men and materials.

11.9. The tests as per EN 50160 and as per distribution licensee's standards shall be carried to ensure the quality of power generated from the DRES.

11.10. The prosumer / DRES shall be responsible to take adequate safety measures to prevent battery power / diesel generator power / back-up power extending to distribution licensee's grid on failure of distribution licensee's grid supply.

11.11. The distribution licensee shall have the right to disconnect the DRES from its system at any time in the following conditions:

(i) Emergencies or maintenance requirement on the distribution licensee's system,

(ii) Hazardous conditions existing on the distribution licensee's system due to operation of DRES or protective equipment as determined by the Distribution Licensee / Transmission Licensee / SLDC, and

(iii) Adverse electrical effects, such as power quality problems, on the electrical equipment of other consumers of the distribution licensee caused by the DRES as determined by the distribution licensee.

(iv) The distribution licensee shall have the right to disconnect the DRES at any time in the event of threat / damage from such DRES to its distribution system to prevent any accident or damage, without any notice.

11.12. When DRES is disconnected, the distribution licensee shall within 24 hours of such disconnection call upon the prosumer to rectify the defect and immediately on such rectification the licensee restores the connection to the DRES concerned.

11.13. The DRES should be capable of detecting an unintended islanding condition. This system must have anti-islanding protection to prevent any unfavourable conditions including failure of supply. IEC-62116 shall be followed to test islanding prevention measure for grid connected photovoltaic inverters.

11.14. Every DRES shall be equipped with automatic synchronization device.

Provided that DRES using inverter shall not be required to have separate synchronization device, if the same is inherently built into the inverter.

11.15. The DRES operating in parallel with electricity system shall be equipped with the protective functions as specified in the CEA (Technical Standards for Connectivity of the Distributed Generation Resources) Regulations 2013 and amendments thereof to sense abnormal conditions on electricity system and cause the DRES to be

automatically disconnected from the electricity system or to prevent the DRES from being connected inappropriately to the electricity system;

11.16. Every time the DRES of the prosumer is synchronized with the distribution system, it shall not cause voltage fluctuation greater than ±5% at the point of inter connection.

11.17. After considering the maintenance and safety procedures, the distribution licensee may require a DRES to provide a manually operated isolating switch between the DRES and the electricity system, which shall meet following requirements:

(i) Allow visible verification that separation has been accomplished;

(ii) Include indications to clearly show open and closed positions;

(iii) Be capable of being reached quickly and conveniently twenty-four (24) hours a day by licensee's personnel without requiring clearance from the applicant;

(iv) Be capable of being locked in the open position;

(v) May not be rated for load break nor may have feature of over-current protection; and

(vi) Be located at a height of at least 2.44 m above the ground level.

11.18. Prior to synchronization of the DRES for the first time with the distribution system of the licensee the applicant and the licensee shall agree on the protection features and control diagrams.

11.19. The power conditioning unit of DRES shall have the features of filtering out harmonics and other distortions before injecting the energy into the system of the distribution utility. The technical standards, power quality standards and inverter standards shall be as per standards as may be specified by CEA from time to time.

11.20. The commissioning test of the DRES shall be carried out in the presence of representatives of consumer/owner of DRES, GEDA and/or concerned officer of the distribution licensee. The commissioning certificate shall be signed by all the above named parties. Date of commissioning shall be recognised from the date on which successful commissioning test is conducted.

11.21. The commissioning certificate must include, details of rated capacity of DRES equipment, details of manufactures, details of metering system, accuracy of meters, etc., total capacity of DRES system including inverters, BESS, and other concerned auxiliary systems, if any.

11.22. The DRES must comply with the applicable provisions of Central Electricity Authority (Technical Standards for Connectivity of the Distributed Generation Resources) Regulations 2013 and amendments thereof;

12. Metering Infrastructure

12.1. All meters installed at the DRES shall comply with the CEA (Installation and Operation of Meters) Regulations, 2006 and subsequent amendments thereof.

12.2. All meters shall have Advanced Metering Infrastructure (AMI) facility with RS 485 (or higher) communication port or any other advance communication facility.

12.3. In case of Net Metering, Net Billing and Group Net Metering, the interconnection point shall be at the prosumer side of the bidirectional meter. In case of Net Metering, Net Billing and Group Net Metering arrangements, the interconnection point shall be at the prosumer side of the bidirectional meter or at such point as may be specified by the Distribution Licensee in accordance with these Regulations and the approved procedure. In case of Gross Metering and Virtual Net Metering arrangements, the interconnection point shall be the delivery point / point of interconnection with the grid, as specified by the Distribution Licensee in accordance with these Regulations and the approved connectivity procedure.

12.4. The generation and bidirectional meter(s) shall be procured, installed and maintained by the distribution licensee. However, if the prosumer wishes to procure the meter(s), he may procure and present them to the distribution licensee for testing and installation.

12.5. The distribution licensee shall undertake meter testing before installation to ensure accuracy of the meter.

12.6. The meter shall be tested or checked only in the presence of the representatives of the prosumer or the third-party owner, as the case may be, and the distribution licensee and as per the procedure specified in the GERC (Electricity Supply Code and Related

Matters) Regulations, 2015, as amended from time to time. If the consumer chooses not to be present at the site for testing, the distribution licensee will carry out such testing and shall give the copy of the meter test report to the consumer for signing.

12.7. If the eligible consumer is under the ambit of time-of-day tariff, both generation and bi- directional shall be capable of recording time of day consumption/ generation.

13. Energy Accounting during Meter Defect/Failure/Burnt

13.1. In case of defective / failure / burnt condition of any meter, the prosumer / DRES shall report the failure, to the distribution licensee in the specified format of distribution licensee.

13.2. The distribution licensee shall replace the meter as specified in the GERC (Electricity Supply Code and Related Matters) Regulations, 2015, as amended from time to time.

13.3. In case meter is burnt due to distribution licensee's actions, no meter cost shall be recovered from prosumer / DRES.

14. Renewable Power Purchase Obligation

14.1. The quantum of electricity consumed by the Eligible Consumer from the DRES under the Net Metering / Net Billing / Group Net metering / Virtual Net Metering shall qualify towards compliance of DISCOM' RPO, if such prosumer / consumer is either not an Obligated Entity or / and such consumer /prosumer do not wish to use consumption energy from DRES for voluntarily RPO requirement.

14.2. All surplus units of DRES purchased by the Distribution Licensee shall qualify towards meeting RPO of Distribution licensee**.**

14.3. Under the Gross Metering Arrangement, the entire quantum of electricity recorded by the Generation Meter shall qualify towards meeting the RPO of the Distribution Licensee."

15. Restrictions and Other provisions

15.1. No DRES and no service connection shall be simultaneously covered under more than one metering arrangement under these Regulations. However, a consumer may switch from one metering arrangement to another in accordance with these Regulations and the procedure approved by the Commission.

15.2. If the consumer / prosumer / participating consumer has supply arrangement from DRES under VNM, he shall not be eligible for Green Energy Open Access. Similarly, If the consumer / prosumer / participating consumer has arrangement / has been arranging supply under GERC Green Energy Open Access Regulations, he shall not be eligible to set up DRES under VNM.

15.3. The conversion of existing standalone Solar Rooftop Project into to Wind-Solar Hybrid project shall be allowed subject to condition that entire RE capacity (Existing + New) shall be governed by the provisions of these Regulations.

15.4. Installation of any new RE capacity by the prosumer or addition of RE capacity without approval of concerned distribution licensee after commissioning of DRES for which Agreement is signed between the Prosumer and Distribution licensee, shall be qualified as unauthorized connection / use and it shall attract penalty for utilization of generation from such new DRES capacity and /or additional DRES capacity at the twice of the energy charge applicable for a period of 3 months or actual period of installation of such new / additional capacity, whichever is lower.

15.5. The maximum capacity of Wind Turbine Generator as part of DRES installed under Net-Metering / Net Billing / Gross Metering / Group Net Metering arrangement shall not exceed 50 KW.

15.6. In respect of DRES set up under various policies of the Government / Orders / Regulations of the Commission including DRES set up under these Regulations, for the purpose of priority of energy settlement, FIFO (First In First Out) principle shall be followed and credit of energy shall be provided as per the provisions of applicable Order / Regulations of the Commission. If the total energy generated from the DRES(s) cannot be accounted for and adjusted in the aforesaid manner, the surplus energy available has to be treated as per specified in these Regulations.

15.7. The deployment, installation and operation of BESS as part of DRES shall be governed by the applicable Regulations as may be notified by the Commission in subject matter.

15.8. In case of Hybrid DRES installed by the prosumer involving two or more different types of RE sources, integration of energy generated from different sources shall be allowed at AC level only with mandatory provisions for separate metering arrangement to record gross generation of energy from each RE sources.

16. Communication facility

The DRES having capacity above 1 MW shall mandatorily install RTU.

Provided that for DRES having capacity less than 1 MW, at the time of installation of DRES, connectivity of such DRES with grid shall be ensured by installation and integration of SIM based Remote Monitoring System with centralized platform in a secured manner as per the Guideline issued by State/ Central Government or its Agency from time to time, as part of compliance requirement.

17. Peer-to-Peer Transactions

The Commission may allow prosumer to sale surplus power generated by DRES to another consumer through Peer-to-Peer transactions in a secured and reliable way with proper accounting and billing mechanism. The Commission may issue separate Regulations or Guidelines on “Implementation of Peer-to-Peer DRES Transactions.

18. Dispute Resolution

In case of any dispute pertaining to these Regulations and its interpretation, it shall be decided by the Commission by observing the prescribed procedure.

Provided that any dispute in pertaining to billing and / or billing amount, would be settled by the Consumer Grievance Redressal Forum and Electricity Ombudsman.

19. Sharing of Carbon Credit benefits

100% of the gross proceeds on account of Carbon Credit benefits to be retained by the prosumer of DRES.

20. Issue of Orders and Directions

Subject to the provisions of the Electricity Act, 2003 and these Regulations, the Commission may, from time to time, issue Orders and practice directions with regard to the implementation of these Regulations and procedures to be followed.

21. Power to give Directions

The Commission shall have power to issue such directions and orders from time to time as considered appropriate for implementation of these Regulations.

22. Power to Relax

The Commission may by general or special order, for reasons to be recorded in writing, and after giving an opportunity of hearing to the parties likely to be affected, may relax any of the provisions of these Regulations on its own motion or on an application made before it by an interested person.

23. Power to amend:

The Commission shall have power to add, vary, alter, suspend, modify, amend, or repeal any provisions of these Regulations from time to time.

24. Power to remove difficulties:

If any difficulty arises in giving effect to the provisions of these Regulations, the Commission may, by an order, make such provisions, not inconsistent with the provisions of the Electricity Act and these Regulations, as may appear to be necessary for removing the difficulty.

Sd/-

RANJEETH KUMAR J., IAS
Secretary,
Gujarat Electricity Regulatory Commission
Gandhinagar, Gujarat

Place: Gandhinagar

Date: 15/05/2026

Annexure-I

Connectivity charges payable by the DRES owner

System Size	Applicable fees per connection
From 1 kW up to 6 kW	INR 1,500
More than 6 kW up to 100 kW	INR 10,000
More than 100 kW up to 1 MW / 4MW	INR 50,000

The Connectivity Charges for DRES shall be payable to the respective Distribution Licensee

Annexure-II-A

Model Application Form for Net Metering / Net Billing / Gross Metering Connection of DRES

To,
The
_____Gujarat Vij Company Ltd. / Distribution Licensee

Subject: Application for Net Metering / Net Billing / Gross Metering connection of Distributed Renewable Energy System (DRES)

I / We _____ intend to connect a Distributed Renewable Energy System in compliance with the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026 and amendments thereto, under Net Metering / Net Billing / Gross Metering arrangement, as per the details furnished below:

A. Applicant and Existing Service Connection Details

Sr. No.	Particulars	Details / Response
1	Applicant / Consumer full name	
2	Address of applicant / consumer	
3	Service connection / consumer number	
4	Name of Sub-Division / Division / Circle	
5	Email ID in capital letters	
6	Mobile / telephone number	
7	Tariff category	
8	Supply voltage level of existing connection	
9	Sanctioned load / contracted demand as per latest electricity bill	_____ kW / _____ kVA / _____ HP
10	Whether any arrears are pending with the Distribution Licensee	Yes / No
11	If arrears are pending, whether such arrears are under dispute before an appropriate forum and interim relief / stay has been granted	Yes / No / Not Applicable
12	Whether latest electricity bill and no-dues / arrears declaration are enclosed	Yes / No

B. DRES and Metering Arrangement Details

Sr. No.	Particulars	Details / Response
1	Type of renewable energy source proposed	Solar / Wind / Hybrid / Other: _____
2	Location of proposed DRES	Rooftop / terrace / building / infrastructure / open land at _____
3	Whether the premises / land is owned by applicant or in legal possession of applicant	Owned / leased / legal possession / other: _____

4	DRES capacity proposed to be connected	AC capacity: _____ kW; DC capacity: _____ kW
5	Metering arrangement applied for	Net Metering / Net Billing / Gross Metering
6	Voltage level at which DRES is proposed to be connected	LT / 11 kV / 22 kV / 33 kV / Other: _____
7	Whether applied capacity is within permissible limit under the Regulations	Yes / No
8	Whether applied capacity is less than or equal to sanctioned load / contracted demand	Yes / No / Not Applicable
9	Whether DRES capacity exceeds contracted demand / sanctioned load	Yes / No
10	If capacity exceeds contracted demand / sanctioned load, details of excess capacity	Excess capacity: _____ kW
11	Whether BESS is integrated as part of DRES	Yes / No
12	If BESS is integrated, provide BESS capacity and charging / discharging capability	Capacity: _____ kW / _____ kWh; minimum 2 hours cycle: Yes / No
13	Whether DRES has automatic isolation / anti-islanding protection	Yes / No
14	Whether separate generation meter / bidirectional meter / check meter is proposed or installed	Generation meter: Yes / No; Bidirectional meter: Yes / No; Check meter: Yes / No
15	Whether communication facility / AMI / modem / RS-485 or other port is provided	Yes / No; Details: _____
16	Expected date of commissioning	
17	GEDA registration / application details, if available	Letter / Registration No. _____ dated _____
18	CEI approval / SLD approval details, if available	

C. Ownership Details

Sr. No.	**Particulars**	**Details / Response**
1	Ownership / development model of DRES	Self-owned / RESCO-owned
2	Whether captive status is claimed for exemption / treatment under applicable law	Yes / No
3	If captive status is claimed, undertaking to comply with Electricity Rules, 2005 and applicable GERC Regulations is enclosed	Yes / No / Not Applicable
4	If DRES is owned by RESCO / third party, name of RESCO / power producer	
5	Registered office address, CIN / registration number and contact details of RESCO / third party, if applicable	
6	Whether separate RESCO-consumer agreement has been / will be executed, if applicable	Yes / No / Not Applicable
7	Whether consumer claims RE attributes or allows DISCOM to use RE generation for RPO compliance, wherever applicable	Claims RE attribute / Allows DISCOM for RPO / Not applicable

Declaration / Undertaking

- I / We declare that the information furnished in this application and the documents enclosed are true and correct to the best of my / our knowledge and belief.
- I / We undertake to comply with the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, as amended from time to time, and the applicable Orders, Codes, procedures and directions of the Commission, CEA, CEI, SLDC, GETCO, GEDA and the Distribution Licensee.
- I / We undertake that any injection of energy before formal commissioning / synchronisation approval shall be treated as inadvertent / lapsed energy and no monetary compensation, credit or adjustment shall be claimed for such energy.
- I / We agree that energy accounting, banking, wheeling losses, open access charges, CSS, AS, electricity duty, ToD adjustment, treatment of surplus / lapsed energy and all other charges shall be governed by the applicable Regulations / Orders of the Commission and the approved procedure of the Distribution Licensee.
- I / We undertake to obtain and maintain all approvals, permissions, test certificates, CEI approvals, GEDA registration / commissioning certificate and other statutory clearances required for installation, interconnection and operation of the DRES.
- I / We agree that the Distribution Licensee may display application and commissioning related information on its website / portal for transparency and administrative convenience.

Signature
Name: _____
Designation / Capacity: _____
Date: _____
Applicant / Consumer / Lead Consumer, as applicable

Documents to be Enclosed

- Latest electricity bill of the applicant / consumer.
- No-dues declaration or details of disputed arrears with stay / interim relief order, if applicable.
- Proof of ownership / lease / legal possession of premises / rooftop / land.
- GEDA registration / acknowledgement, if available.
- Single Line Diagram and wiring diagram.
- Technical details of modules / turbines / inverter / BESS / transformer / RMU / CT-PT / meters, as applicable.
- Details of RESCO / third-party owner and authorisation, if applicable.

Acknowledgment

Received an application for Net Metering / Net Billing / Gross Metering connection from:

Sr. No.	**Particulars**	**Details / Response**
1	Name of Applicant	
2	Consumer / Service Connection Number(s)	
3	DRES Capacity applied for	_____ kW (AC) / _____ kW (DC)
4	Application Registration Number	
5	Date and Time of Receipt	

Signature
Name: _____
Designation _____
Date: _____
Name and Signature of Receiving Officer / Designation

Annexure-II-B

Model Application Form for Group Net Metering Connection of DRES

To,
The

_____ Gujarat Vij Company Ltd. / Distribution Licensee

Subject: Application for Group Net Metering connection of Distributed Renewable Energy System (DRES)

I / We _____ intend to connect a Distributed Renewable Energy System under Group Net Metering arrangement, in compliance with the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026 and amendments thereto, for adjustment of energy in more than one service connection of the same consumer and same tariff category, as per the details furnished below:

A. Prosumer / Main Consumer Details

Sr. No.	**Particulars**	**Details / Response**
1	Name of prosumer / consumer installing DRES	
2	Address of prosumer / consumer	
3	Main service connection / consumer number where DRES is installed or proposed	
4	Name of Sub-Division / Division / Circle	
5	Email ID in capital letters	
6	Mobile / telephone number	
7	Tariff category of prosumer and participating connections	
8	Supply voltage level	
9	Sanctioned load / contracted demand of prosumer / main connection	_____ kW / _____ kVA / _____ HP
10	Whether all participating service connections are in the same name and same tariff category	Yes / No
11	Whether any arrears are pending in any participating connection	Yes / No
12	If arrears are pending, whether such arrears are under dispute before an appropriate forum and interim relief / stay has been granted	Yes / No / Not Applicable

B. DRES Details

Sr. No.	**Particulars**	**Details / Response**
1	Type of renewable energy source proposed	Solar / Wind / Hybrid / Other: _____

Sr. No.	Particulars	Details / Response
2	Location of proposed DRES	Rooftop / terrace / building / infrastructure / open land at _____
3	Whether DRES premises / land is owned by prosumer or in legal possession of prosumer	Owned / leased / legal possession / other: _____
4	DRES capacity proposed to be connected	AC capacity: _____ kW; DC capacity: _____ kW
5	Whether applied capacity is within permissible limit for Group Net Metering under the Regulations	Yes / No
6	Aggregate contracted demand / sanctioned load of all participating connections	_____ kW / _____ kVA
7	Whether DRES capacity exceeds contracted demand / sanctioned load, wherever applicable	Yes / No
8	If DRES capacity exceeds contracted demand / sanctioned load, details of excess capacity	Excess capacity: _____ kW
9	Whether BESS is integrated as part of DRES	Yes / No
10	If BESS is integrated, provide BESS capacity and charging / discharging capability	Capacity: _____ kW / _____ kWh; minimum 2 hours cycle: Yes / No
11	Voltage level at which DRES is proposed to be connected	LT / 11 kV / 22 kV / 33 kV / Other: _____
12	Whether DRES has automatic isolation / anti-islanding protection	Yes / No
13	Whether generation meter / bidirectional meter / check meter is proposed or installed	Generation meter: Yes / No; Bidirectional meter: Yes / No; Check meter: Yes / No
14	Whether communication facility / AMI / modem / RS-485 or other port is provided	Yes / No; Details: _____
15	Ownership / development model	Self-owned / captive / group captive / RESCO-owned / third-party-owned
16	Whether captive status is claimed	Yes / No
17	Expected date of commissioning	
18	GEDA registration / application details, if available	Letter / Registration No. _____ dated _____
19	CEI approval / SLD / earthing / wiring approval details, if available	

C. Details of Participating Connections for Energy Adjustment

Sr. No.	Service Connection No.	Name of consumer	Address / premises	Tariff category	Name of Sdn/Div/Circle	Sanctioned load / CD	Voltage level	Allocation ratio / share
1								
2								
3								
4								

5								
6								
7								

D. Specific Declaration for Group Net Metering

- I / We declare that the service connections proposed for energy adjustment under Group Net Metering belong to the same consumer and the same tariff category, as required under the Regulations.
- I / We declare that the allocation ratio / share specified above shall be used by the Distribution Licensee for energy accounting and billing adjustment until changed in accordance with the Regulations and approved procedure.
- I / We agree that change in allocation ratio shall be permitted only as per the Regulations / Orders of the Commission and the procedure approved by the Distribution Licensee.

Declaration / Undertaking

- I / We declare that the information furnished in this application and the documents enclosed are true and correct to the best of my / our knowledge and belief.
- I / We undertake to comply with the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, as amended from time to time, and the applicable Orders, Codes, procedures and directions of the Commission, CEA, CEI, SLDC, GETCO, GEDA and the Distribution Licensee.
- I / We undertake that any injection of energy before formal commissioning / synchronisation approval shall be treated as inadvertent / lapsed energy and no monetary compensation, credit or adjustment shall be claimed for such energy.
- I / We agree that energy accounting, banking, wheeling losses, open access charges, CSS, AS, electricity duty, ToD adjustment, treatment of surplus / lapsed energy and all other charges shall be governed by the applicable Regulations / Orders of the Commission and the approved procedure of the Distribution Licensee.
- I / We undertake to obtain and maintain all approvals, permissions, test certificates, CEI approvals, GEDA registration / commissioning certificate and other statutory clearances required for installation, interconnection and operation of the DRES.
- I / We agree that the Distribution Licensee may display application and commissioning related information on its website / portal for transparency and administrative convenience.

Signature	
Name:	_____
Designation	_____
Date:	_____
Applicant / Consumer / Lead Consumer, as applicable	

Documents to be Enclosed

- Latest electricity bills of prosumer and all participating service connections.
- No-dues declaration or details of disputed arrears with stay / interim relief order, if applicable, for all participating connections.
- Proof of ownership / lease / legal possession of DRES premises / rooftop / land.
- GEDA registration / acknowledgement, if available.
- Single Line Diagram and wiring diagram.
- Technical details of modules / turbines / inverter / BESS / transformer / RMU / CT-PT / meters, as applicable.
- Anti-islanding and protection certificate / undertaking.
- Statement of allocation ratio / share signed by the prosumer / consumer.
- RESCO / third-party details and authorisation, if applicable.

Acknowledgment

Received an application for Group Net Metering connection from:

Signature Name:	_____
Designation	_____
Date:	_____
Name and Signature of Receiving Officer / Designation	

Sr. No.	**Particulars**	**Details / Response**
1	Name of Applicant	
2	Consumer / Service Connection Number(s)	
3	DRES Capacity applied for	_____ kW (AC) / _____ kW (DC)
4	Application Registration Number	
5	Date and Time of Receipt	

Annexure-II-C

Model Application Form for Virtual Net Metering Connection of DRES

To,
The

_____ Gujarat Vij Company Ltd. / Distribution Licensee

Subject: Application for Virtual Net Metering connection of Distributed Renewable Energy System (DRES)

I / We _____, being the DRES owner / RESCO / lead consumer authorised by the participating consumers, intend to connect a Distributed Renewable Energy System under Virtual Net Metering arrangement, in compliance with the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026 and amendments thereto, for adjustment of energy in the service connections of participating consumers belonging to the same tariff category and situated within the same Distribution Licensee area of supply, as per the details furnished below:

A. Applicant / Lead or Nodal Consumer / Consumer Group Details

Sr. No.	**Particulars**	**Details / Response**
1	Name of applicant filing application	DRES owner / RESCO / Lead Consumer / Other: _____
2	Administrative name of VNM Consumer Group, if any	For identification only: _____
3	Name of Lead / Nodal Consumer authorised by participating consumers	
4	Consumer number of Lead / Nodal Consumer, if applicable	
5	Address of Lead / Nodal Consumer / Applicant	
6	Email ID in capital letters	
7	Mobile / telephone number	
8	Whether authorisation / consent letter of participating consumers is enclosed	Yes / No
9	Name of Sub-Division / Division / Circle for Lead / Nodal Consumer	

B. Ownership / Development Model and DRES Owner Details

Sr. No.	**Particulars**	**Details / Response**
1	Ownership / development model of DRES	Jointly-owned by consumers or RESCO-owned / third-party-owned
2	Name of DRES owner / RESCO / power producer	
3	Registered office address of DRES owner / RESCO / power producer	

4	CIN / registration number / legal status of DRES owner / RESCO / power producer	
5	Name, designation, mobile number and email ID of authorised signatory	
6	Whether separate RESCO-consumer commercial agreement has been / will be executed, if applicable	Yes / No / Not Applicable
7	Whether captive status is claimed	Yes / No
8	If captive status is claimed, undertaking to comply with Electricity Rules, 2005 and applicable GERC Regulations is enclosed	Yes / No / Not Applicable
9	Whether consumers claim RE attribute or allow DISCOM to use generation for RPO compliance, wherever applicable	Claims RE attribute / Allows DISCOM for RPO / Not applicable

C. DRES Project and Connectivity Details

Sr. No.	**Particulars**	**Details / Response**
1	Type of renewable energy source proposed	Solar / Wind / Hybrid / Other: _____
2	DRES location	Village / Taluka / District / Survey No. / address: _____
3	Whether DRES land / premises is owned / leased / in legal possession of DRES owner	Owned / leased / legal possession / other: _____
4	DRES capacity proposed to be connected	AC capacity: _____ kW; DC capacity: _____ kW
5	Whether applied capacity is within permissible limit for Virtual Net Metering under the Regulations	Yes / No
6	Aggregate contracted demand / sanctioned load of participating consumers	_____ kW / _____ kVA
7	Whether DRES capacity exceeds aggregate contracted demand / sanctioned load, wherever applicable	Yes / No
8	If DRES capacity exceeds aggregate contracted demand / sanctioned load, details of excess capacity	Excess capacity: _____ kW
9	Whether BESS is integrated as part of DRES	Yes / No
10	If BESS is integrated, provide BESS capacity and charging / discharging capability	Capacity: _____ kW / _____ kWh; minimum 2 hours cycle: Yes / No
11	Proposed voltage level for grid connectivity	11 kV / 22 kV / Other as approved: _____
12	Nearest GETCO 66 kV sub-station and proposed delivery point	
13	Dedicated evacuation line details up to delivery point	Voltage: _____ kV; length: _____ km; to be created by DRES owner: Yes / No

Sr. No.	Particulars	Details / Response
14	Name of feeder / sub-station / connectivity point, if available	
15	Whether DRES has automatic isolation / anti-islanding protection	Yes / No
16	Whether Special Energy Meter / ABT meter / generation meter / check meter is proposed or installed	SEM / ABT: Yes / No; Generation meter: Yes / No; Check meter: Yes / No
17	Whether communication facility / RTU / AMI / modem / real-time data transfer is provided	Yes / No; Details: _____
18	Expected date of commissioning	
19	GEDA registration / application details, if available	Letter / Registration No. _____ dated _____
20	CEI approval / SLD approval details, if available	

D. Details of Participating Consumers for Energy Adjustment

Sr.	Name of consumer	Service connection No.	Address / premises	Sub-Division / Division/Circle	Tariff category	Sanctioned load / CD	Voltage level	Allocation ratio / share	Signature / consent
1									
2									
3									
4									
5									
6									
7									
8									
9									

E. Specific Declaration for Virtual Net Metering

- I / We declare that all participating consumers are situated within the area of supply of the same Distribution Licensee and belong to the same tariff category, as required under the Regulations.
- I / We declare that the allocation ratio / share specified above shall be used by the Distribution Licensee for energy accounting and billing adjustment after applying applicable wheeling losses and charges.
- I / We agree that change in allocation ratio shall be permitted only as per the Regulations / Orders of the Commission and the procedure approved by the Distribution Licensee.
- I / We agree that in case of RESCO-owned DRES, the separate RESCO-consumer commercial agreement shall remain between the RESCO and the participating consumers, and the Distribution Licensee shall not be responsible for recovery of RESCO dues or disputes arising out of such mutual commercial arrangement, except to the extent governed by the Regulations / Orders of the Commission.

- I / We undertake that CSS, AS, wheeling charges, wheeling losses, banking charges, electricity duty, open access charges, ToD adjustment and all other charges shall be payable as per the applicable Regulations / Orders of the Commission, subject to exemptions / concessions, if any, specifically provided therein.

Declaration / Undertaking

- I / We declare that the information furnished in this application and the documents enclosed are true and correct to the best of my / our knowledge and belief.
- I / We undertake to comply with the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, as amended from time to time, and the applicable Orders, Codes, procedures and directions of the Commission, CEA, CEI, SLDC, GETCO, GEDA and the Distribution Licensee.
- I / We undertake that any injection of energy before formal commissioning / synchronisation approval shall be treated as inadvertent / lapsed energy and no monetary compensation, credit or adjustment shall be claimed for such energy.
- I / We agree that energy accounting, banking, wheeling losses, open access charges, CSS, AS, electricity duty, ToD adjustment, treatment of surplus / lapsed energy and all other charges shall be governed by the applicable Regulations / Orders of the Commission and the approved procedure of the Distribution Licensee.
- I / We undertake to obtain and maintain all approvals, permissions, test certificates, CEI approvals, GEDA registration / commissioning certificate and other statutory clearances required for installation, interconnection and operation of the DRES.
- I / We agree that the Distribution Licensee may display application and commissioning related information on its website / portal for transparency and administrative convenience.

Signature
Name: _____
Designation _____
Date: _____
Applicant / Consumer / Lead Consumer, as applicable

Documents to be Enclosed

- Latest electricity bills of all participating consumers.
- No-dues declaration or details of disputed arrears with stay / interim relief order, if applicable, for all participating consumers.
- Authorisation / consent letter appointing Lead / Nodal Consumer.
- Statement of allocation ratio / share signed by participating consumers.
- Proof of ownership / lease / legal possession of DRES land / premises.
- GEDA registration / acknowledgement, if available.
- Single Line Diagram and wiring diagram.

- Technical details of modules / turbines / inverter / BESS / transformer / RMU / CT-PT / meters, as applicable.
- Anti-islanding and protection certificate / undertaking.
- Meter and CT-PT testing certificates, if available.
- CEI approval / application acknowledgement, if available.
- Connectivity application / approval details for RE-based project, if available.
- Details of proposed dedicated evacuation line up to delivery point.
- RESCO / third-party owner details, authorisation and undertaking, if applicable.
- Captive / group captive compliance undertaking, if captive benefit is claimed.

Acknowledgment

Received an application for Virtual Net Metering connection from:

Sr. No.	**Particulars**	**Details / Response**
1	Name of Applicant	
2	Consumer / Service Connection Number(s)	
3	DRES Capacity applied for	_____ kW (AC) / _____ kW (DC)
4	Application Registration Number	
5	Date and Time of Receipt	

Signature

Name: _____

Designation _____

Date: _____

Name and Signature of Receiving Officer / Designation

Annexure-III

Model

Inter connection Agreement between Distribution Licensees and prosumer / consumer

(installing DRES under Net-Metering / Net Billing / Group Net-Metering / Gross Metering Arrangement)

This Inter Connection Agreement is made and entered into at _____ on this ____ day of the _____ month of the year _____

Between

Shri / Smt. / M/s. _____, having Consumer No. _____, Contract Demand / Sanctioned Load of _____ kW/kVA/HP, situated at _____, being a consumer of the Distribution Licensee and having installed / proposed to install the DRES described in Appendix-I hereto (hereinafter referred to as the "Consumer" or "Prosumer", which expression shall, unless repugnant to the context or meaning thereof, include its permitted assigns and successors), as the Party of the First Part;

AND

_____ (name of Distribution Licensee), a company registered under the Companies Act, 1956 / 2013 and functioning as a Distribution Licensee under the Electricity Act, 2003, having its registered / corporate office at _____ (hereinafter referred to as the "Distribution Licensee" or "DISCOM", which expression shall, unless repugnant to the context or meaning thereof, include its successors and assigns), as the Party of the Second Part.

The Consumer / Prosumer and the Distribution Licensee are hereinafter individually referred to as a "Party" and collectively as the "Parties".

AND WHEREAS

The Consumer / Prosumer has registered with the Gujarat Energy Development Agency ("GEDA")

/ agency designated by the Government of Gujarat, vide letter No. _____ dated _____ for setting up a Distributed Renewable Energy System ("DRES") of _____ kW (AC), with / without BESS, at _____, on premises owned / legally possessed by the Consumer / Prosumer, as per the details set out in Appendix-I.

AND WHEREAS

The DRES first party is covered by the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026 issued by vide Notification No……., dated…….

AND WHEREAS

in case of Group Net Metering, the service connections proposed for adjustment of energy shall be in the same name and same tariff category and located within the same area of supply of the Distribution Licensee, as specified in Appendix-II.

AND WHEREAS

the present Agreement is being entered into as an interconnection / metering / energy accounting agreement in terms of the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, the GERC (Terms and Conditions for Green Energy Open Access) Regulations, 2024, and other applicable Regulations / Orders / directions of the Commission, as amended from time to time.

AND WHEREAS

the Distribution Licensee agrees to provide grid connectivity / interconnection and to undertake energy accounting and billing adjustment for the DRES, subject to technical feasibility, execution of this Agreement, payment of applicable charges and compliance by the Consumer / Prosumer with the applicable Policy, Rules, Regulations, Codes and directions.

AND WHEREAS

The consumer, the first party under the agreement, hereby acknowledges that the present agreement has been entered into by the both the parties, taking into account the notification of the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026 as amended from time to time and the GERC (Terms & Conditions for Green Energy Open Access) Regulations, 2024 and other applicable Regulations / Order of the GERC,

parties agree to abide by any Regulations/Orders/decision of the GERC and further agrees to incorporate requisite modifications and amendments in the agreement as per the same, if required. The first party does not dispute the applicability of the GERC Regulations/Order/directives and must make necessary modifications in the agreement accordingly.

AND WHEREAS

The Distribution Licensee agrees to provide grid connectivity to the Consumer / Prosumer and injection of the electricity generated from his DRES of capacity **____KW (AC)** into the power system of Distribution Licensee as per conditions of this agreement and in compliance with the applicable Policy / Rules/ Regulations / Codes (as amended from time to time) by the Consumer which includes-

1. Government of Gujarat Renewable Energy Policy -2025
2. Central Electricity Authority (Measures relating to Safety and Electric Supply) Regulations, 2023.
3. Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2013 as amended from time to time
4. Central Electricity Authority (Installation and Operation of Meters) Regulation 2006 as amended from time to time.
5. Gujarat Electricity Regulatory Commission (Electricity Supply Code & Related Matters) Regulations, 2015 as amended from time to time,
6. Gujarat Electricity Regulatory Commission Distribution Code ,2004 and amendments thereto,
7. Instruction, Directions and Circulars issued by Chief Electrical Inspector from time to time.
8. CEA (Technical Standards for connectivity of the Distributed Generations) Regulations, 2013 as amended from time to time.
9. Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026.

10. GERC (Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources) Regulations, 2019

AND WHEREAS

The consumer / prosumer has opted following option under this Agreement for utilization of energy generated from DRES and connected with grid:

(a) Net Metering

(b) Net Billing

(c) Group Net-Metering

(d) Gross Metering

The details of the prosumer / consumer is as under:

Sr. No.	Name of consumer	Location	Consumer No.	Contracted demand	Tariff Category	Voltage level

In case of Group Net-Metering, the details of participant consumers are as under:

Sr. No.	Name of consumer	Location	Consumer No.	Name of Sdn/Div/ Circle	Contracted demand	Tariff Category	Voltage level
1							

Both the parties hereby agree as follows:

1. Eligibility and General Conditions

1.1 The Consumer / Prosumer shall be a consumer of the local Distribution Licensee and shall own the premises or be in legal possession of the premises, including rooftop, terrace,

building, infrastructure, open land or part thereof, where the DRES is installed / proposed to be installed.

1.2 The DRES shall be owned and operated by the Consumer / Prosumer for use under the selected metering arrangement. Where the DRES is owned / operated through a third party / RESCO, the same shall be governed by the applicable provisions of the Regulations and separate agreement / arrangement, wherever required.

1.3 The Consumer / Prosumer shall not have pending arrears with the Distribution Licensee, except where such arrears are in dispute before an appropriate legal forum and interim relief / stay has been granted by such forum.

1.4 The capacity of the DRES shall be within the limits specified in the Regulations and shall be subject to technical feasibility at the point of interconnection.

1.5 For Net Metering and Net Billing arrangement, the minimum size of DRES shall be 1 kW (AC) and the maximum size shall be 1000 kW (AC), or such capacity as may be specified by the Commission from time to time.

1.6 For Group Net Metering arrangement, the minimum size of DRES shall be 6 kW (AC) and the maximum size shall be 1000 kW (AC), subject to the requirement that the participating service connections are in the same name and same tariff category within the same area of supply of the Distribution Licensee.

1.7 For Gross Metering arrangement, the minimum size of DRES shall be 1 kW (AC) and the maximum size shall be 4000 kW (AC), or such capacity as may be specified by the Commission from time to time.

1.8 Where the Consumer / Prosumer having contract demand above 100 kW installs DRES capacity in excess of the Contract Demand / Sanctioned Load under Net Metering, Net Billing or Group Net Metering arrangement, such excess capacity shall be permitted only if the DRES includes BESS having provision for at least two hours of charging / discharging cycles per day for at least 50% of the DRES capacity which is in excess of the Contract Demand / Sanctioned Load.

1.9 The Consumer / Prosumer shall meet all technical, safety, metering, communication, scheduling and energy accounting requirements as specified under the Regulations / Orders of the Commission, CEA Regulations, Grid Code, Distribution Code and directions of the

Distribution Licensee / SLDC / GETCO / CEI.

2. Technical and Interconnection Requirements

2.1 The DRES and metering system shall conform to the technical standards, connectivity requirements and safety requirements specified under the applicable Policy, GERC Regulations, CEA Regulations, Distribution Code and the approved procedures of the Distribution Licensee.

2.2 The Consumer / Prosumer shall install, before interconnection, suitable isolation devices, both automatic and manual, including anti-islanding protection, and shall provide access to the Distribution Licensee for operation of such devices wherever required for repair, maintenance, safety or reliable operation of the distribution system.

2.3 In case of outage on the Distribution Licensee system, the DRES shall automatically disconnect / isolate and shall not inject power into the Distribution Licensee system, unless special transfer and isolating capabilities have been installed and approved in accordance with applicable standards.

2.4 The technical specifications of meters, CT/PT units, communication equipment, protection system, inverter, transformer, cables, breakers and other equipment shall comply with applicable BIS / IEC / IEEE standards, CEA Regulations, DISCOM standards and directions of the Commission / CEI / SLDC / GETCO / DISCOM.

2.5 The Distribution Licensee / GETCO / SLDC, as applicable, shall specify the interface point, interconnection point, delivery point, metering point, metering arrangement, protection requirements and communication requirements as per applicable Regulations and approved procedures.

2.6 The Consumer / Prosumer shall adhere to power quality requirements, including harmonics, voltage, frequency, flicker, reactive power and other operating parameters as specified under applicable standards and directions.

2.7 The Consumer / Prosumer shall provide operational data such as voltage, frequency, generation, injection, breaker / isolator position and any other data as required by the Distribution Licensee / SLDC / GETCO / Commission and shall provide online real-time data transfer facility wherever required.

2.8 Where the DRES capacity is above 1 MW, the Consumer / Prosumer shall install RTU / communication facility and such other interface equipment as may be mandated by the Regulations and directions of SLDC / GETCO / DISCOM.

2.9 The Consumer / Prosumer shall not synchronise the DRES with the distribution system unless all technical, protection, metering, safety and communication requirements are complied with and approval for synchronisation / commissioning has been granted by the competent authority.

3. Approvals, Clearances and Commissioning

3.1 The Consumer / Prosumer shall obtain and maintain all necessary approvals, permissions, permits and clearances relating to land / premises, electrical safety, grid connectivity, metering, communication, commissioning, operation and maintenance of the DRES.

3.2 The Consumer / Prosumer shall obtain approval from the Chief Electrical Inspector, commissioning certificate from GEDA / designated agency, meter / CTPT testing certificate from NABL accredited laboratory, and any other certificate required by the Distribution Licensee or competent authority before commissioning.

3.3 The Consumer / Prosumer shall submit all documents, drawings, single line diagram, earthing diagram, protection scheme, equipment test certificates, connectivity approval, no-dues certificate and other documents as required under the Regulations and approved procedure.

3.4 Energy injected prior to commissioning / synchronisation approval shall be treated as inadvertent / lapsed energy and the Consumer / Prosumer shall not be eligible for any monetary compensation for such energy.

4. Safety

4.1 The Consumer / Prosumer shall comply with the Central Electricity Authority (Measures relating to Safety and Electric Supply) Regulations, 2023, as amended from time to time, and all applicable directions of the Chief Electrical Inspector.

4.2 The design, installation, maintenance and operation of the DRES shall be carried out in a manner conducive to the safety of the DRES, distribution system, grid, operating personnel, consumers and the public at large.

4.3 If the Distribution Licensee / SLDC / GETCO determines that the DRES causes damage or produces adverse effects affecting other consumers, distribution assets, grid security or safety, the Consumer / Prosumer shall immediately disconnect the DRES upon such direction and rectify the defect at its own cost before reconnection.

4.4 Any change, alteration, modification or addition of capacity in the DRES after availing the selected metering arrangement shall be carried out only after obtaining prior written approval of the Distribution Licensee and after submission of necessary test certificates and approvals.

4.5 The Consumer / Prosumer shall be solely responsible for any accident to human beings / animals or damage to property arising due to back-feeding from the DRES when grid supply is off, to the extent determined by the Chief Electrical Inspector or competent authority.

5. Access and Disconnection

5.1 Distribution Licensee shall have access to metering equipment and disconnecting means of the DRES , both automatic and manual, at all times.

5.2 In emergency or outage situation, where there is no access to the disconnecting means, both automatic and manual, such as a switch or breaker, Distribution Licensee may disconnect service to the premises of the Consumer.

5.3 The Distribution Licensee reserves the right to disconnect the DRES at any time in the event of threat / damage from the DRES to its distribution system, personnel or public safety, without prior notice, subject to applicable Regulations / Orders.

5.4 Disconnection under this clause shall not absolve the Consumer / Prosumer from liability to pay applicable charges, nor shall it create any claim against the Distribution Licensee, unless such disconnection is found to be contrary to applicable Regulations / Orders by the competent forum.

6. Metering

6.1 Metering arrangement shall be in accordance with the CEA (Installation and Operation of Meters) Regulations, 2006, GERC Regulations / Orders and the approved procedure of the Distribution Licensee.

6.2 The Consumer / Prosumer shall install generation meter, bidirectional meter, main meter,

check meter, ABT / Special Energy Meter, CT/PT, communication equipment and other metering equipment as may be specified by the Distribution Licensee / GETCO / SLDC / Commission.

6.3 For Net Metering, Net Billing and Group Net Metering, bidirectional meter shall be installed at the point of supply / interconnection, and generation meter shall record total generation of the DRES.

6.4 For Gross Metering, the total generation from the DRES and the total consumption by the Consumer / Prosumer shall be recorded separately through appropriate metering arrangements.

6.5 For Group Net Metering, meter reading of the bidirectional meter where the DRES is located and the meters of all participating service connections shall be undertaken concurrently for the relevant billing period.

6.6 All meters shall have suitable communication facility, AMI / RS-485 or higher communication port or any other advanced communication facility as specified by the Distribution Licensee / Commission.

6.7 The cost of meters, CT/PT, testing, sealing, communication, installation and replacement shall be borne by the Consumer / Prosumer as per applicable Regulations / Orders / estimate of the Distribution Licensee, unless otherwise specified by the Commission.

7. Energy Accounting and commercial settlement

The energy accounting and commercial settlement shall be undertaken in accordance with the GERC (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, the applicable Tariff Orders and other Orders / Regulations of the Commission, as amended from time to time.

The following provisions shall apply depending upon the metering arrangement selected by the Consumer / Prosumer.

7.1 Net Metering

The electricity exported or injected into the grid from the DRES during a billing period shall be adjusted against electricity drawn or imported from the grid during the same billing cycle.

(a) For residential category prosumers, the entire exported / injected energy during a billing cycle shall be eligible for adjustment against import during the same billing cycle without levy of banking charges. Any surplus energy remaining after such adjustment shall be treated as deemed purchase by the Distribution Licensee at Rs. 2.25 per kWh or such rate as may be specified by the Commission from time to time.

(b) For prosumers other than residential category, adjustment shall be allowed up to 30% of the total energy drawn / imported from the Distribution Licensee during the relevant billing period, subject to payment of applicable banking charges. Any exported / injected energy beyond the permissible limit shall be treated as lapsed energy, unless otherwise specified by the Commission.

(c) Where the Consumer / Prosumer is covered under Time-of-Day tariff, exported energy during off-peak hours shall be eligible for adjustment against consumption during off-peak hours only, while exported energy during peak hours shall be eligible for adjustment against consumption during peak as well as off-peak hours, subject to the Regulations.

(d) The exported / injected electricity measured in kWh / kVAh shall be utilised only to offset electricity consumption measured in kWh / kVAh and shall not be utilised to compensate any other fee, fixed / demand charges, Government levy or other charges levied by the Distribution Licensee.

7.2 Net Billing Arrangement

(a) The energy generated by the DRES may be first used for self-consumption and surplus energy injected into the Grid or energy drawn from the Grid shall be billed as per following equation:

Energy Bill of consumer = Fixed Charges + Other applicable charges and levies + (EDL × TRST) - (ERE × TRR) ; Where:

Fixed Charges *mean the Fixed/Demand Charges as applicable to the consumer category as per the applicable retail supply Tariff Order.*

Other applicable charges *and levies mean electricity duty, fuel and power purchase price adjustment surcharge etc.*

EDL *means the energy drawn from the Grid by the prosumer.*

TRST *means the applicable retail supply tariff of the concerned consumer category as per the applicable retail supply Tariff Order of the Commission.*

ERE *means the energy exported / injected by DRES in the grid in the billing period*

TRR *means generic tariff determined by Commission from time to time in its tariff order for respective RE base sources for purchase of energy injected in grid from DRES.*

Provided that the monetary value of the exported energy is credited based on the tariff determined by the Commission as applicable as on date of DRES is commissioned and shall be applicable for whole life of the DRES.

7.3 Group Net Metering Arrangement

(a) The energy exported or injected from the DRES shall be allocated to the participating service connections in accordance with the allocation ratio specified in Appendix-II for the purpose of offsetting their electricity consumption during the relevant billing period.

(b) The energy exported / injected and made available after accounting for applicable losses shall be adjusted against energy drawn from the grid by participating service connections in accordance with the allocation ratio and on 15-minute time block basis, wherever applicable under the Regulations.

(c) The difference between energy injected from the DRES and energy consumed by the participating service connections in the corresponding time block shall be treated as banked energy, and shall be treated as per the Regulations and applicable Orders of the Commission.

(d) For participating service connections other than residential category, credit of banked energy shall be allowed up to 30% of total energy drawn from the Distribution Licensee

during the relevant billing period, subject to payment of applicable banking charges. Such banked energy shall be adjusted within the same billing cycle and shall not be carried forward; unutilised banked energy shall be treated as lapsed energy.

(e) For residential category, energy available at the consumption end as per allocation ratio shall be adjusted against drawal from the grid during the same billing cycle without levy of banking charges. Any surplus energy remaining after such adjustment shall be treated as deemed purchase by the Distribution Licensee at Rs. 2.25 per kWh or such rate as may be specified by the Commission from time to time.

(f) Change in allocation ratio under Group Net Metering shall be permitted once in a financial year, subject to intimation one month before commencement of the financial year or such procedure as may be specified by the Commission / Distribution Licensee.

7.4 Gross Metering Arrangement

Under Gross Metering, the total energy generated from the DRES shall be accounted separately from the total energy consumed by the Consumer / Prosumer.

(a) The total energy generated from the DRES and injected into the distribution grid shall be accounted at the generic tariff determined by the Commission for the respective renewable energy source and applicable from time to time.

(b) The total energy consumed by the Consumer / Prosumer from the grid shall be billed at the applicable retail supply tariff and other applicable charges / levies.

(c) If the monetary value of energy exported / injected from the DRES exceeds the monetary value of energy consumption from the Distribution Licensee during a billing cycle, such excess amount shall be carried forward as credit in the next billing cycle, unless otherwise specified by the Commission.

8. Open Access charges

(a) The Consumer / Prosumer shall pay all applicable charges, including wheeling charges, wheeling losses, banking charges, Cross Subsidy Surcharge, Additional Surcharge,

electricity duty, taxes, fees, Government levies and other charges as specified under the applicable Regulations / Orders of the Commission and laws in force.

(b) Where a self-owned DRES is installed on the Consumer / Prosumer premises under Net Metering, Net Billing or Gross Metering arrangement, wheeling charges and wheeling losses shall be dealt with as provided under the Regulations / Orders of the Commission.

(c) Where energy is wheeled to participating service connections under Group Net Metering, the adjustment shall be after considering applicable wheeling losses and payment of applicable charges as specified by the Commission.

(d) Banking charges, if applicable, shall be levied on the quantum of banked energy offset against consumption from the grid during the billing cycle, in accordance with the GERC Green Energy Open Access Regulations and relevant Orders of the Commission.

(e) The Consumer / Prosumer shall continue to pay fixed / demand charges, minimum charges, Government levies and other charges as applicable, irrespective of the availability of energy export / credit from the DRES.

(f) In case the DRES is claimed as captive, the Consumer / Prosumer shall satisfy the ownership and consumption criteria prescribed under the Electricity Rules, 2005 and applicable Regulations / Orders. If captive status is not maintained, CSS / AS and other charges shall be levied as applicable.

(g) In case DRES do not qualify the criteria for captive plant and captive user, Cross Subsidy Surcharge and Additional Surcharge shall be levied for consumption of energy from such DRES. Incase consumer consuming energy from such DRES does not claim RE attribute of energy and allow DISCOM to avail the same for RPO compliance, such consumer shall be allowed to claim concession in the Cross Subsidy Surcharge and Additional Surcharge as per the applicable Order/Regulation of the Commission. The Cross Subsidy Surcharge and Additional Surcharge shall be exempted for consumption of energy by residential consumers from non-captive DRES, if the DRES capacity set up under RESCO mode is not exceeding aggregate capacity worked out with consideration of 2 kW per participant residential consumers.

9. Scheduling, Forecasting and Deviation Settlement

(a) The injection of energy from the DRES into the grid shall be subject to scheduling, forecasting and deviation settlement requirements under the applicable GERC Regulations / Orders, where applicable.

(b) The Consumer / Prosumer shall comply with instructions of SLDC, GETCO and the Distribution Licensee for scheduling, curtailment, grid security, outage management and safe operation of the system.

10. Renewable Energy Attribute, REC and RPO

(a) Treatment of Renewable Energy Certificate, renewable energy attribute and Renewable Purchase Obligation shall be governed by applicable Regulations / Orders of the Commission and CERC REC Regulations, as amended from time to time.

(b) Where the Consumer / Prosumer does not claim REC or do not voluntarily use the renewable energy attribute for its own RPO / green claim, the Distribution Licensee may consider such generation towards its RPO compliance to the extent permitted under the Regulations / Orders of the Commission.

11. Liabilities and Indemnity

(a) The Consumer / Prosumer shall indemnify and keep indemnified the Distribution Licensee, its officers, employees, directors and agents from all claims, damages, losses, penalties, liabilities and costs arising from design, installation, operation, maintenance, defect, accident, non-compliance, back-feeding or unsafe operation of the DRES, except to the extent attributable to willful default or gross negligence of the Distribution Licensee.

(b) The Distribution Licensee shall not be liable for delivery, grant or realisation of any subsidy, fiscal incentive or other benefit provided by the Central / State Government or any agency.

(c) The Distribution Licensee shall not be liable for any indirect, consequential, incidental, punitive or special damages, including loss of profits, business interruption, loss of contract or loss of goodwill arising out of this Agreement.

(d) The Consumer / Prosumer shall remain responsible for all acts, omissions and defaults of its contractors, vendors, operators, employees and agents engaged for installation, operation or maintenance of the DRES.

12. Electricity Duty

Applicability of Electricity Duty shall be governed as per the Gujarat Electricity Duty Act, 1958 and as amended from time to time.

13. Change in Arrangement, Capacity, Ownership or Consumer Details

Any change in metering arrangement, capacity, technology, BESS configuration, ownership, consumer name, service connection, allocation ratio or any other material detail shall require prior intimation / approval as per the Regulations and procedure specified by the Distribution Licensee / Commission.

Switching between Net Metering, Net Billing and Gross Metering shall be permitted only in the manner and frequency specified under the Regulations / Orders of the Commission.

In case of permanent disconnection, change of ownership, transfer of premises or abandonment of DRES, the Consumer / Prosumer shall intimate the Distribution Licensee and comply with the settlement and disconnection procedure specified by the Distribution Licensee / Commission.

14. Dispute Resolution

All disputes or differences between the Parties arising out of or in connection with this Agreement shall be first tried to be settled through mutual negotiation, promptly, equitably and in good faith. In the event that such differences or disputes between the Parties are not settled through mutual negotiations within sixty (60) days or mutually extended period, after such dispute arises, then for any dispute in billing pertaining to energy injection and billing amount, it would be settled by the Consumer Grievance Redressal Forum and Electricity Ombudsman. Any other issues pertaining to the Regulations and its interpretation; it shall be decided by the Gujarat Electricity

Regulatory Commission in accordance with applicable procedure.

15. Term and Termination

(a) The term of this Agreement shall be 25 years or the useful life of DRES, whichever is earlier, unless terminated earlier in accordance with this clause and the applicable Regulations / Orders.

(b) The prosumer/consumer or the DISCOM may terminate this Agreement by giving 90 days prior written notice to the other Parties, subject to settlement of all dues, disconnection formalities, regulatory compliance and approval / acceptance of the Distribution Licensee wherever required.

(c) Upon termination, the prosumer /consumer shall disconnect the DRES from the Distribution Licensee's system in a timely and safe manner and to the satisfaction of the Distribution Licensee.

(d) Termination of this Agreement shall not affect accrued rights and liabilities of the Parties, including payment of bills, open access charges, banking charges, CSS, AS, electricity duty, penalties, compensation, indemnity and other dues payable up to the date of termination.

16. Communication facility

The DRES having capacity above 1 MW shall mandatorily install RTU.

Provided that for DRES having capacity less than 1 MW, at the time of installation of DRES, connectivity of such DRES with grid shall be ensured by installation and integration of SIM based Remote Monitoring System with centralized platform in a secured manner as per the Guideline issued by State/ Central Government or its Agency from time to time, as part of compliance requirement.

17. Communication

The names of the officials and their addresses, for the purpose of any communication in relation to the matters covered under this Agreement shall be as under:

In respect of the DISCOM	In respect of the prosumer / Consumer (consumer address along with valid email id)

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their authorized officers, and copies delivered to each Party, as of the day and year herein above stated.

FOR AND ON BEHALF OF DISCOM	FOR AND ON BEHALF OF THE PROSUMER / CONSUMER
Authorized Signatory **WITNESSES** 1._____ ( ) 2._____ ( )	_____ Authorized Signatory **WITNESSES** 1._____ ( ) 2._____ ( )

Appendix-I:

Details of DRES and Selected Metering Arrangement

Particular	**Details**
Name of Consumer / Prosumer	
Consumer No.	
Tariff Category	
Contract Demand / Sanctioned Load	
Address/Location of DRES	
Premises owned / legally possessed by	
Renewable Energy Source / Technology	Solar / Wind / Hybrid / Other
DRES Capacity (AC)	
BESS Capacity, if applicable	
Selected Metering Arrangement	Net Metering / Net Billing / Group Net Metering / Gross Metering
GEDA / Designated Agency Registration No. and Date	
Interconnection Voltage Level	
Interconnection / Delivery Point	
Feeder / Transformer / Substation Details	
Commissioning Date	
Meter Details	
Whether REC / RPO attribute claimed by Consumer	Yes / No

Appendix-II:

Details of Participating Service Connections (for Group Net Metering only)

Sr. No.	Name of Consumer	Location / Address	Consumer No.	Name of Sdn/Div/ Circle	Contract Demand / Sanctioned Load	Tariff Category	Voltage Level	Allocation Ratio (%)
1								
2								
3								
4								
5								
6								

Appendix-III:

Technical and Metering Details

Particular	**Details**
Generation Meter Make / No. / Class	
Bidirectional / Main Meter Make / No. / Class	
Check Meter Make / No. / Class	
CT/PT Ratio and Details	
Communication Facility / AMI Details	
Protection System Details	
Isolator / Breaker Details	
Anti-Islanding Protection Details	
RTU / Real-time Data Facility, if applicable	
Meter Testing Certificate Details	
CEI Approval Details	
Other Technical Approvals	

Appendix-IV:

Documents / Approvals to be Submitted

1. Application form and registration certificate from GEDA / designated agency;
2. Proof of ownership / legal possession of premises;
3. No-dues certificate / status of disputed arrears with interim relief, if any;
4. Single Line Diagram and protection scheme;
5. CEI approval / safety clearance;
6. Meter / CTPT testing certificate from NABL accredited laboratory;
7. Equipment compliance certificates / BIS / IEC certificates, as applicable;
8. Connectivity approval / technical feasibility approval;
9. Commissioning certificate from GEDA / designated agency;
10. Authorisation / board resolution / power of attorney, where applicable;
11. Any other document specified by the Distribution Licensee / Commission.

Annexure- IV

Model Agreement for Distributed Renewable Energy System (DRES) Set up under Virtual Net Metering arrangement for Captive Use

THIS AGREEMENT IS MADE AND ENTERED INTO AT _____ ON THE _____ DAY OF THE _____ MONTHS OF _____

Between

1. The consumers whose names, consumer numbers, service connection details, premises details, tariff category, contract demand / sanctioned load and respective allocation share are set out in Appendix-I along with their respective signatures for executing this agreement, being eligible consumers under the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, and having agreed to jointly set up / own / use the Distributed Renewable Energy System under Virtual Net Metering arrangement, shall collectively constitute the Party of the **First Part** to this Agreement. The said consumers are hereinafter collectively referred to as the "**Eligible Consumers**" or "**Participating Consumers**" or, for administrative identification only, as the "**_____ VNM Consumer Group**". The use of name of such group is for administrative purpose only and all rights, obligations, liabilities and responsibilities under this Agreement shall remain with the individual participating consumers jointly and severally, in accordance with these Regulations and this Agreement.

2. _____ (DISCOM), registered under the provisions of the Companies Act, 1956 having its registered and corporate office at _____(hereinafter called "**DISCOM**") as second party to this Agreement.

AND, WHEREAS

The Participating Consumers have, by an authorisation / consent letter annexed as Appendix-II, nominated Shri / Smt. / M/s. _____, Consumer No. _____, as the Lead / Nodal

Consumer for the limited purpose of submitting applications, signing this Agreement, communicating with the Distribution Licensee, receiving notices, coordinating metering, billing and energy accounting matters, coordinating with distribution licensee and participating consumers and doing all acts necessary for implementation of the Virtual Net Metering arrangement on behalf of the Participating Consumers. It is clarified that such nomination shall be for administrative convenience only and shall not absolve any Participating Consumer from its obligations, liabilities or compliance requirements under this Agreement, the Regulations and other applicable laws.

AND, WHEREAS

The Gujarat Energy Development Agency ("GEDA") vide letter No. _____ dated _____ has registered the DRES of **___ kW (AC)** (as per the details set out in Appendix-III) at _____ to be connected with nearest GETCO 66 kV _____ Substation through _____ kV dedicated distribution line within the jurisdiction of _____ (DISCOM) level for own use of eligible consumers.

AND WHEREAS

The present Agreement is being entered into as an interconnection / wheeling / energy accounting agreement for DRES under Virtual Net Metering arrangement, in terms of the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, the GERC (Terms and Conditions for Green Energy Open Access) Regulations, 2024 and other applicable Regulations / Orders / directions of the Commission, as amended from time to time.

AND WHEREAS

The consumer, the first party under the agreement, hereby acknowledges that the present agreement has been entered into by the both the parties, taking into account the notification of the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources)

Regulations, 2026 as amended from time to time and the GERC (Terms & Conditions for Green Energy Open Access) Regulations, 2024 and other applicable Regulations / Order of the GERC, parties agree to abide by any Regulations/Orders/decision of the GERC and further agrees to incorporate requisite modifications and amendments in the agreement as per the same, if required. The first party does not dispute the applicability of the GERC Regulations/Order/directives and must make necessary modifications in the agreement accordingly.

AND WHEREAS

The Distribution Licensee agrees to provide grid connectivity / interconnection and to undertake energy accounting for the DRES and the Participating Consumers, subject to technical feasibility, execution of this Agreement, payment of applicable charges and compliance with the applicable Policy / Rules / Regulations / Codes by the Participating Consumers.

The applicable legal and regulatory framework includes, inter alia:

Government of Gujarat Renewable Energy Policy, 2025, as amended from time to time;

1. Central Electricity Authority (Measures relating to Safety and Electric Supply) Regulations, 2023, as amended from time to time;
2. Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 / 2013, as applicable and as amended from time to time;
3. Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006, as amended from time to time;
4. Gujarat Electricity Regulatory Commission (Electricity Supply Code and Related Matters) Regulations, 2015, as amended from time to time;
5. Gujarat Electricity Regulatory Commission Distribution Code, 2004 and amendments thereto;
6. Instructions, directions and circulars issued by the Chief Electrical Inspector from time to time;
7. GERC (Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources) Regulations, 2019, as amended from time to time;

8. GERC (Terms and Conditions for Green Energy Open Access) Regulations, 2024, as amended from time to time;
9. GERC (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, as amended from time to time; and
10. Any other applicable Regulations / Orders / directions of the Commission, CEA, SLDC, GETCO, DISCOM, GEDA and other competent authorities.

It is hereby agreed between the parties as follows:

1. Eligibility and General Conditions

1.1 The eligible consumers shall own, install, operate and maintain the DRES for supply / allocation of renewable energy to the Participating Consumers under Virtual Net Metering arrangement, subject to the provisions of the Regulations and this Agreement.

1.2 Each Participating Consumer shall be a consumer of the local Distribution Licensee, situated within the same area of supply of the Distribution Licensee, and shall belong to the same tariff category as required under the Regulations.

1.3 The Participating Consumers and their service connections shall not have pending arrears with the Distribution Licensee, except where such arrears are in dispute before an appropriate legal forum and interim relief / stay has been granted by such forum.

1.4 The minimum size of DRES in aggregate under Virtual Net Metering arrangement shall be 100 kW (AC), while the maximum size in aggregate shall not exceed 4000 kW (AC), subject to technical feasibility and the applicable Regulations / Orders of the Commission.

1.5 Except in case of residential category consumers, where the DRES capacity is in excess of the aggregate contract demand / sanctioned load of all Participating Consumers, such excess capacity shall be allowed only if the DRES includes BESS having provision for at least two hours of charging / discharging cycles per day for at least 50% of the DRES capacity which is in excess of such aggregate contract demand / sanctioned load.

1.6 The DRES shall be connected with the distribution licensee network at 11 kV / 22 kV voltage level, as applicable, with delivery point at the 66 kV sub-station of GETCO through a dedicated evacuation line to be created by the DRES Owner at its own cost.

1.7 The Participating Consumers confirm that they are aware of the technical standards, safety conditions, metering requirements, scheduling requirements, open access charges, banking charges, CSS, AS, electricity duty and other conditions applicable to the DRES and the Virtual Net Metering arrangement.

1.8 The allocation ratio / share of energy from the DRES among the Participating Consumers shall be as specified in Appendix-I and shall be used by the Distribution Licensee for energy accounting and billing adjustment, subject to applicable wheeling loss and other charges.

1.9 The RESCO / Power Producer and the Participating Consumers shall not claim any right contrary to the Regulations / Orders of the Commission merely on the basis of this Agreement. In case of any inconsistency, the Regulations / Orders of the Commission shall prevail.

2. Technical and Interconnection Requirements

2.1 The DRES shall have installed / ensured for installation of suitable isolation devices, both automatic and manual, prior to connection of the DRES with the distribution system and shall permit access to the DISCOM for operation of such devices, wherever required for repair, maintenance, safety or reliable operation of the distribution system.

2.2 In case of power outage on the Distribution Licensee's system, the DRES shall automatically shut down unless special transfer and isolating capabilities have been installed and approved in accordance with applicable standards and directions of the Distribution Licensee / CEI / Commission.

2.3 The technical specifications of meters, CT/PT units, communication equipment, protection system, inverter, transformer, cables, breakers and other equipment shall be in compliance with the applicable CEA Regulations, DISCOM standards, Grid Code, Distribution Code and directions of the Commission / CEI / SLDC / GETCO / DISCOM.

2.4 All equipment connected to the distribution system shall comply with relevant Indian Standards / BIS / IEC / IEEE standards and all electrical installations shall comply with applicable safety regulations and technical standards.

2.5 The Distribution Licensee / GETCO/ SLDC shall specify the interconnection point, delivery point, metering point, metering arrangement, protection requirements and

communication requirements as per the applicable Regulations / Orders of the Commission and the approved procedure for grant of connectivity.

2.6 The DRES shall adhere to power quality requirements, including harmonics, voltage, frequency, flicker and other parameters as specified under applicable standards and directions of the Commission / CEA / DISCOM.

2.7 The Participating consumers shall furnish operational data such as voltage, frequency, breaker / isolator position, generation, injection and any other data as may be required by the DISCOM / SLDC / GETCO / Commission and shall provide facilities for online transfer of real-time operational data wherever required.

2.8 The Participating consumers shall obtain all requisite approvals, including CEI approval, connectivity approval, commissioning certificate, metering approval, safety clearance and other statutory approvals before commissioning / synchronisation of the DRES and shall furnish copies of such approvals to the Distribution Licensee / SLDC / GETCO.

2.9 The Participating Consumers agree that the Distribution Licensee may host information relating to application, registration, connectivity, commissioning and allocation of the DRES on its website / web portal for transparency and administrative convenience.

2.10 The Participating Consumers shall be responsible for safe operation, maintenance and rectification of defects of the DRES up to the delivery point / interconnection point, as applicable, and the Distribution Licensee shall be responsible beyond such point to the extent provided under the Regulations.

2.11 Where the DRES capacity is above 1 MW, the RESCO / Power Producer shall install RTU / communication facility as mandated under the Regulations and directions of the SLDC / GETCO / DISCOM.

3. Safety:

3.1 Eligible Consumers shall comply with the Central Electricity Authority (Measures Relating to Safety and Electricity Supply) Regulations 2023 as amended from time to time and all applicable directions of the Chief Electrical Inspector.

3.2 The design, installation, maintenance and operation of the DRES shall be carried out in a manner conducive to the safety of the DRES, the distribution system, the grid, operating personnel, consumers and the public at large.

3.3 If the Distribution Licensee /SLDC/ GETCO/ determines that the DRES causes damage or produces adverse effects affecting other consumers, distribution assets, grid security or safety, DRES shall be disconnected immediately upon such direction and rectify the defect at its own cost before reconnection.

3.4 Any change, alteration, modification or addition of capacity in the DRES after availing Virtual Net Metering facility shall be carried out only after obtaining prior written permission from the Distribution Licensee and after submission of necessary test certificates and approvals as may be required.

3.5 The participating consumers shall be solely responsible for any accident to human beings / animals or damage to property arising due to back-feeding from the DRES when grid supply is off, to the extent decided by the Chief Electrical Inspector or competent authority.

4. Clearances and Approvals:

The Eligible Consumers shall obtain and maintain all necessary approvals, permissions, permits and clearances relating to land / premises, environment, electrical safety, grid connectivity, metering, communication, commissioning, operation and maintenance of the DRES. The Participating Consumers shall provide necessary consumer-level documents, no-dues certificates, consent letters and authorisations as may be required for implementation of the Virtual Net Metering arrangement.

5. Access and Disconnection:

5.1 DISCOM shall have access to metering equipment and disconnecting means of DRES, both automatic and manual, at all times.

5.2 In emergency or outage situation, where there is no access to any disconnecting means, both automatic and manual, such as a switch or breaker, DISCOM may disconnect service to the premise and in such scenario, the eligible consumer shall not have any right to object or to claim any sum from DISCOM citing such immediate disconnection.

5.3 The Distribution Licensee reserves the right to disconnect the DRES at any time in the event of threat / damage from the DRES to its distribution system, personnel or public safety, without prior notice, subject to applicable Regulations / Orders.

6. Liabilities and Indemnity

6.1 The participating consumers shall indemnify and keep indemnified the DISCOM, its officers, employees, directors and agents from all claims, damages, losses, penalties, liabilities and costs arising from the design, installation, operation, maintenance, defect, accident, non-compliance, back-feeding or unsafe operation of the DRES, except to the extent attributable to willful default or gross negligence of the DISCOM.

6.2 The Participating Consumers shall indemnify the DISCOM against claims, liabilities, penalties and costs arising from consumer-level non-compliance, misrepresentation, unauthorised use, non-payment of lawful charges, incorrect consumer information, or breach of this Agreement attributable to them.

6.3 The DISCOM shall not be liable to the Participating Consumers for any indirect, consequential, incidental, punitive or special damages, including loss of profits, business interruption, loss of contract or loss of goodwill, arising out of this Agreement.

6.4 The Participating Consumers shall remain jointly and severally responsible for compliance with this Agreement to the extent of their respective obligations, without prejudice to the separate commercial arrangement between them.

7. Metering:

7.1 Metering arrangement shall be as per the Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006, as amended from time to time, the GERC Regulations / Orders and the approved procedure of the Distribution Licensee.

7.2 The DRES shall have installed Special Energy Meter / ABT compliant meter capable of recording energy injection into the grid on 15-minute time block basis under the Virtual Net Metering mechanism, along with generation meter, check meter and communication facility wherever required.

7.3 Meters shall be installed at the generation point and at the delivery / interconnection point, as specified by the Distribution Licensee. The consumer meters of the Participating Consumers shall be read concurrently with the energy injected / exported from the DRES for the purpose of energy accounting and billing adjustment.

7.4 The Participating Consumers shall bear metering, CT/PT, testing, sealing, communication

and related costs as per the applicable Regulations / Orders / estimate of the DISCOM, unless otherwise specified by the Commission.

8. Energy Accounting and commercial settlement mechanism

The Distribution Licensee shall undertake meter reading of energy injected /exported from DRES at the delivery point and consumer meters of all participating Consumers according to the regular billing period concurrently.

8.1 The energy exported or injected into the grid from the DRES under Virtual Net Metering arrangement shall be allocated to the Participating Consumers in accordance with the allocation ratio specified in Appendix-I for offsetting their electricity consumption during the relevant billing period.

8.2 The energy exported or injected from the DRES in the grid during any billing period and made available at the consumption end after accounting for applicable losses shall be adjusted against the energy drawn from the grid by the participating consumers, in accordance with the allocation ratio specified in the agreement with the Distribution Licensee, on a 15-minute time block basis. The difference between the energy injected from the DRES (as available at the consumption point) and the energy consumed by the participating consumers in the corresponding 15-minute time block shall be treated as banked energy.

8.3 In case of participating consumers other than the residential category, credit of such banked energy shall be allowed up to a maximum of thirty percent (30%) of the total energy drawn by the participating consumers from the Distribution Licensee during the relevant billing period, subject to payment of applicable banking charges as specified under the GERC Green Energy Open Access Regulations and applicable Orders / Regulations of the Commission, as amended from time to time:

Such banked energy shall be adjusted within the same billing cycle and shall not be permitted to be carried forward to subsequent billing cycles: Any unutilized banked energy remaining at the end of the billing cycle shall be treated as lapsed energy.

8.4 In case of participating consumers in the residential category, the energy injected from the

DRES and available at the consumption end, as per the allocation ratio specified in the agreement with the Distribution Licensee, shall be adjusted against the energy drawn from the grid during the same billing cycle, without levy of banking charges. Any surplus energy remaining after such adjustment shall be treated as deemed purchase by the concerned Distribution Licensee at the rate of Rs. 2.25 per kWh, or at such rate as may be specified by the Commission from time to time.

8.5 In case of net drawl of electricity by participating consumers from the distribution licensee during any billing period after providing adjustment of exported /injected energy in terms of above, the distribution licensee shall raise a bill as per applicable retail tariff for such net electricity consumption.

8.6 Where the Participating Consumers are under Time-of-Day tariff, banked energy available during peak period shall be allowed to be utilised during peak as well as off-peak period, whereas banked energy available during off-peak period shall be utilised only during off-peak period, subject to the applicable Regulations / Orders of the Commission.

8.7 The injection of energy from DRES to the grid shall be subject to scheduling as per the GERC (Forecasting, Scheduling, Deviation settlement Mechanism and related matters of Wind and Solar Generating Stations) Regulations, 2019 as amended from time to time and relevant Orders of the Commission.

8.8 Energy injected prior to commissioning of the DRES shall be treated as inadvertent / lapsed energy and the Participating Consumers shall not be eligible to receive any monetary compensation for such inadvertent power.

9. Open Access charges

9.1 The Participating Consumers shall be subjected to wheeling charges, wheeling losses, banking charges, Cross Subsidy Surcharge (“CSS”), Additional Surcharge (“AS”) and other applicable charges as specified under the GERC (Green Energy Open Access) Regulations, 2024, the GERC (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, RE technology-wise tariff orders and other applicable Orders / Regulations of the Commission, as amended from time to time subject to the Regulations.

9.2 The banking charges at the rate as decided by the Order / Regulation of the Commission,

shall be levied on the quantum of banked energy off-set against the consumption from grid during the billing cycle. Provided that banking charges shall not be levied in case the participating consumers under Virtual metering arrangement belongs to residential (RGP) category of consumer.

9.3 The participating connection(s) have to fulfil the qualification criteria for Captive power plant as specified in Electricity Rules 2005 and GERC (Green Energy Open Access) Regulations 2024 as amended from time to time.

9.4 In case DRES do not qualify the criteria for captive plant and captive user, Cross Subsidy Surcharge and Additional Surcharge shall be levied for consumption of energy from such DRES. Incase consumer consuming energy from such DRES does not claim RE attribute of energy and allow DISCOM to avail the same for RPO compliance, such consumer shall be allowed to claim concession in the Cross Subsidy Surcharge and Additional Surcharge as per the applicable Order/Regulation of the Commission. The Cross Subsidy Surcharge and Additional Surcharge shall be exempted for consumption of energy by residential consumers from non-captive DRES, if the DRES capacity set up under RESCO mode is not exceeding aggregate capacity worked out with consideration of 2 kW per participant residential consumers.

10. Electricity Duty:

Applicability of electricity duty, tax, cess, fee and other Government levies shall be governed by the Gujarat Electricity Duty Act, 1958, other applicable laws and amendments thereto. The Participating Consumers / RESCO / Power Producer shall be responsible for payment of such duty / levy as applicable under law.

11. Renewable Energy Attribute and RPO

11.1 The renewable energy attribute of the electricity consumed by the Participating Consumers from the DRES shall be treated in accordance with the applicable Regulations / Orders of the Commission.

11.2 Where the Participating Consumers are not Obligated Entities and / or do not wish to use consumption of energy from the DRES for voluntary RPO requirement, the quantum of

electricity consumed from the DRES may qualify towards compliance of the Distribution Licensee's RPO, subject to applicable Regulations / Orders.

11.3 Any concession in CSS / AS on account of non-claim of renewable energy attribute by the Participating Consumers and use of such attribute by the Distribution Licensee for RPO compliance shall be governed by the applicable Regulations / Orders of the Commission.

12. Connection Costs and Evacuation Infrastructure

12.1 The required evacuation infrastructure up to the delivery point, including dedicated line, metering, CT/PT, protection, communication, isolators and related equipment, shall be created by the DRES Owner at its own cost, unless otherwise specified by the Commission.

12.2 The Participating Consumers shall bear all costs relating to setting up, interconnection, evacuation, metering, system strengthening, testing and commissioning of the DRES as per the applicable Regulations / Orders / estimate of the DISCOM.

12.3 Any modification, upgradation or strengthening required in the distribution system for connecting the DRES shall be undertaken and charged in accordance with the applicable Regulations / Orders of the Commission and the approved procedure of the Distribution Licensee.

13. Change in Allocation Ratio / Participating Consumers

13.1 Change in allocation ratio shall be permitted only once in a financial year, subject to intimation to the Distribution Licensee at least one month prior to commencement of the financial year and shall be effective from the beginning of such financial year, subject to approval / acceptance by the Distribution Licensee and applicable Regulations.

14. Lead / Nodal Consumer

14.1 The Participating Consumers shall appoint / nominate one of the Participating Consumers as the Lead / Nodal Consumer for administrative purposes only.

14.2 All communications issued by the Distribution Licensee may be addressed to the Lead / Nodal Consumer and such communication shall be deemed to have been served upon all

Participating Consumers. It shall be the responsibility of the Lead / Nodal Consumer to communicate the same to other Participating Consumers.

14.3 The Lead / Nodal Consumer shall not be treated as the owner of the DRES merely by reason of such nomination and such nomination shall not affect the obligations of other Participating Consumers under this Agreement.

15. Dispute Resolution:

15.1 All disputes or differences between the Parties arising out of or in connection with this Agreement shall be first tried to be settled through mutual negotiation, promptly, equitably and in good faith

15.2 In the event that such differences or disputes between the Parties are not settled through mutual negotiations within sixty (60) days or mutually extended period, after such dispute arises, then for

(a) any dispute in billing pertaining to energy injection and billing amount, it would be settled by the Consumer Grievance Redressal Forum and Electricity Ombudsman.

(b) any other issues pertaining to the Regulations and its interpretation; it shall be decided by the Gujarat Electricity Regulatory Commission in accordance with applicable procedure.

16. Term and Termination:

16.1 The term of this Agreement shall be 25 years or the useful life of DRES, whichever is earlier, unless terminated earlier in accordance with this clause and the applicable Regulations / Orders.

16.2 The Participating Consumers acting through the Lead / Nodal Consumer, or the DISCOM may terminate this Agreement by giving 90 days prior written notice to the other Parties, subject to settlement of all dues, disconnection formalities, regulatory compliance and approval / acceptance of the Distribution Licensee wherever required.

16.3 Upon termination, the participating consumers shall disconnect the DRES from the Distribution Licensee's system in a timely and safe manner and to the satisfaction of the Distribution Licensee.

16.4 Termination of this Agreement shall not affect accrued rights and liabilities of the Parties, including payment of bills, open access charges, banking charges, CSS, AS, electricity duty, penalties, compensation, indemnity and other dues payable up to the date of termination.

17. Governing Law and Jurisdiction:

This Agreement shall be governed by the Electricity Act, 2003, the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, the GERC (Terms and Conditions for Green Energy Open Access) Regulations, 2024, the GERC Supply Code, Distribution Code, applicable CEA Regulations and all other applicable Regulations / Orders / directions, as amended from time to time.

18. Communication facility

The DRES having capacity above 1 MW shall mandatorily install RTU.
Provided that for DRES having capacity less than 1 MW, at the time of installation of DRES, connectivity of such DRES with grid shall be ensured by installation and integration of SIM based Remote Monitoring System with centralized platform in a secured manner as per the Guideline issued by State/ Central Government or its Agency from time to time, as part of compliance requirement.

19. Communication:

The names of the officials and their addresses, for the purpose of any communication in relation to the matters covered under this Agreement shall be as under:

In respect of the DISCOM	Lead / Nodal Consumer and Participating Consumers (with consumer address along with valid email id)

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their authorized officers, and copies delivered to each Party, as of the day and year herein above stated.

FOR AND ON BEHALF OF DISCOM	FOR AND ON BEHALF OF THE CONSUMER
Authorized Signatory	_____ Authorized Signatory
WITNESSES	**WITNESSES**
1._____ ( )	1._____ ( )
2._____ ( )	2._____ ( )

Appendix-I- List of Participant Consumers:

Sr. No.	Name of Consumer	Consumer No.	Premises / Address	Name of Sdn/Div/Circle	Tariff Category	Contract Demand / Sanctioned Load	Voltage Level	Allocation Share / Allocated Capacity	Signature
1									
2									

Name and signature of witness

Name and Signature of Lead Consumer

Name and Signature of DISCOM Nodal Officer (Along with Stamp)

Appendix-II

Authorisation / Consent for Lead / Nodal Consumer

We, the Participating Consumers listed in Appendix-I, hereby nominate Shri / Smt. / M/s. _____, Consumer No. _____, as Lead / Nodal Consumer for the limited purpose of coordination with the DISCOM for implementation of the Virtual Net Metering arrangement. The nomination is for administrative convenience only and shall not absolve any Participating Consumer of its obligations under the Agreement, applicable Regulations and other laws.

1				
2				
3				
4				

Appendix-III

Details of DRES

Name of lead consumer	
Registered Office / Address	
DRES Location/Address	
RE Technology / Source	
DRES Capacity in kW (AC)	
BESS Capacity, if applicable	
GEDA Registration No. and Date	
Voltage Level / Interconnection Point / Delivery Point	
Nearest GETCO 66 kV Sub-station and Dedicated Line Details	

Appendix-IV

Documents / Technical Details to be submitted

1. GEDA registration certificate / certificate from agency designated by Government of Gujarat;
2. Connectivity approval / in-principle consent / final connectivity approval;
3. CEI approval, single line diagram,
4. Meter / CTPT testing certificate from NABL accredited laboratory;
5. Protection scheme, relay details, anti-islanding certificate and synchronisation details;
6. Technical certificates / IEC / BIS compliance documents for major equipment;
7. No-dues certificates / consumer consent letters / lead consumer authorisation;
8. Details of dedicated evacuation line, interconnection point and delivery point;
9. BESS details, if applicable;
10. Any other document required by DISCOM / GETCO / SLDC / GEDA / CEI / Commission time to time, as part of compliance requirement.

Annexure- V

Model Agreement for Distributed Renewable Energy System (DRES)

Set up under Virtual Net Metering arrangement under RESCO / Third Party Ownership Model

THIS AGREEMENT IS MADE AND ENTERED INTO AT _____ ON THE _____ DAY OF THE _____ MONTH OF _____, 20____

Between

1. M/s. _____, a Renewable Energy Service Company / Power Producer / Third Part RE Generator, registered under the provisions of the Companies Act, 2013 / applicable law, having its registered office at _____, and being the owner / developer / operator of the Distributed Renewable Energy System described in Appendix-I hereto (hereinafter referred to as the "RESCO", "Power Producer" or "DRES Owner", which expression shall, unless repugnant to the context or meaning thereof, include its successors and permitted assigns), as the Party of the First Part;

AND

2. The consumers whose names, consumer numbers, service connection details, premises details, tariff category, contract demand / sanctioned load and respective allocation share are set out in Appendix-II hereto, being eligible consumers under the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, and having agreed to receive allocation / adjustment of renewable energy from the DRES under Virtual Net Metering arrangement, shall collectively constitute the Party of the Second Part to this Agreement. The said consumers are hereinafter collectively referred to as the "Eligible Consumers" or "Participating Consumers" or, for administrative identification only, as the "_____ VNM Consumer Group". The use of such group name shall be for administrative and identification purposes only and shall not create any separate legal entity, partnership, association of persons, company, society or body corporate. The rights, obligations, liabilities and responsibilities of the Participating Consumers under this Agreement shall remain with the individual Participating Consumers, jointly and severally to the extent applicable under this Agreement, the Regulations and other applicable laws;

AND

3. _____ (DISCOM), registered under the provisions of the Companies Act, 1956 / 2013, having its registered and corporate office at

_____ (hereinafter referred to as the "Distribution Licensee" or "DISCOM", which expression shall, unless repugnant to the context or meaning thereof, include its successors and assigns), as the Party of the Third Part.

The RESCO / Power Producer, the Participating Consumers and the DISCOM are hereinafter individually referred to as a "Party" and collectively as the "Parties".

AND WHEREAS

The RESCO / Power Producer has set up / proposes to set up a Distributed Renewable Energy System ("DRES") of _____ kW (AC), with / without BESS, at _____, the details whereof are set out in Appendix-I, for injection of renewable energy into the distribution network under Virtual Net Metering arrangement for benefit of the eligible consumers/ participating consumers.

AND WHEREAS

The Participating Consumers have entered into / propose to enter into a separate mutual agreement with the RESCO / Power Producer for supply, payment and other commercial terms relating to consumption of energy from the DRES owned by the RESCO. It is clarified that such mutual agreement between the RESCO and the Participating Consumers shall not form part of this Agreement for adjudication by the DISCOM, and the DISCOM shall not be a party to any dispute arising out of such mutual commercial arrangement, except to the extent of metering, wheeling, energy accounting, billing and charges governed by the Regulations / Orders of the Commission.

AND WHEREAS

The Participating Consumers have, by an authorisation / consent letter annexed as Appendix-III, nominated Shri / Smt. / M/s. _____, Consumer No. _____, as the Lead / Nodal Consumer for the limited purpose of submitting applications, signing this Agreement, communicating with the Distribution Licensee, receiving notices, coordinating metering, billing and energy accounting matters, coordinating with distribution licensee and participating consumers and doing all acts necessary for implementation of the Virtual Net Metering arrangement on behalf of the Participating Consumers. It is clarified that such nomination shall be for administrative convenience only and shall not absolve any

Participating Consumer from its obligations, liabilities or compliance requirements under this Agreement, the Regulations and other applicable laws.

AND WHEREAS

The Gujarat Energy Development Agency ("GEDA") / agency designated by the Government of Gujarat vide letter No. _____ dated _____ has registered the DRES of _____ kW (AC), as per the details set out in Appendix-I, to be connected with the nearest GETCO 66 kV _____ Sub-station through _____ kV dedicated distribution line within the jurisdiction of _____ DISCOM.

AND WHEREAS

The present Agreement is being entered into as an interconnection / wheeling / energy accounting agreement for a RESCO-owned DRES under Virtual Net Metering arrangement, in terms of the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, the GERC (Terms and Conditions for Green Energy Open Access) Regulations, 2024 and other applicable Regulations / Orders / directions of the Commission, as amended from time to time.

AND WHEREAS

The Parties acknowledge that this Agreement is subject to the Electricity Act, 2003, the applicable Rules, Regulations, Codes, Orders and directions of the Commission / CEA / Government authorities, as amended from time to time, and agree to incorporate such modifications in this Agreement as may be required due to any subsequent Regulations / Orders / decisions of the Commission or other competent authority.

AND WHEREAS

The Distribution Licensee agrees to provide grid connectivity / interconnection and to undertake energy accounting for the DRES and the Participating Consumers, subject to technical feasibility, execution of this Agreement, payment of applicable charges and compliance with the applicable Policy / Rules / Regulations / Codes by the RESCO / Power Producer and the Participating Consumers.

The applicable legal and regulatory framework includes, inter alia:

1. Government of Gujarat Renewable Energy Policy, 2025, as amended from time to time;
2. Central Electricity Authority (Measures relating to Safety and Electric Supply) Regulations, 2023, as amended from time to time;
3. Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 / 2013, as applicable and as amended from time to time;
4. Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006, as amended from time to time;
5. Gujarat Electricity Regulatory Commission (Electricity Supply Code and Related Matters) Regulations, 2015, as amended from time to time;
6. Gujarat Electricity Regulatory Commission Distribution Code, 2004 and amendments thereto;
7. Instructions, directions and circulars issued by the Chief Electrical Inspector from time to time;
8. GERC (Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources) Regulations, 2019, as amended from time to time;
9. GERC (Terms and Conditions for Green Energy Open Access) Regulations, 2024, as amended from time to time;
10. GERC (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, as amended from time to time; and
11. Any other applicable Regulations / Orders / directions of the Commission, CEA, SLDC, GETCO, DISCOM, GEDA and other competent authorities.

It is hereby agreed between the Parties as follows:

1. Eligibility and General Conditions

1.1 The RESCO / Power Producer shall own, install, operate and maintain the DRES under the RESCO / third party ownership model for supply / allocation of renewable energy to the Participating Consumers under Virtual Net Metering arrangement, subject to the provisions of the Regulations and this Agreement.

1.2 Each Participating Consumer shall be a consumer of the local Distribution Licensee, situated within the same area of supply of the Distribution Licensee, and shall belong to the same tariff category as required under the Regulations.

1.3 The Participating Consumers and their service connections shall not have pending arrears with the Distribution Licensee, except where such arrears are in dispute before an appropriate legal forum and interim relief / stay has been granted by such forum.

1.4 The minimum size of DRES in aggregate under Virtual Net Metering arrangement shall be 100 kW (AC), while the maximum size in aggregate shall not exceed 4000 kW (AC), subject to technical feasibility and the applicable Regulations / Orders of the Commission.

1.5 Except in case of residential category consumers, where the DRES capacity is in excess of the aggregate contract demand / sanctioned load of all Participating Consumers, such excess capacity shall be allowed only if the DRES includes BESS having provision for at least two hours of charging / discharging cycles per day for at least 50% of the DRES capacity which is in excess of such aggregate contract demand / sanctioned load.

1.6 The DRES shall be connected with the distribution licensee network at 11 kV / 22 kV voltage level, as applicable, with delivery point at the 66 kV sub-station of GETCO through a dedicated evacuation line to be created by the DRES Owner / RESCO at its own cost.

1.7 The RESCO / Power Producer and the Participating Consumers confirm that they are aware of the technical standards, safety conditions, metering requirements, scheduling requirements, open access charges, banking charges, CSS, AS, electricity duty and other conditions applicable to the DRES and the Virtual Net Metering arrangement.

1.8 The allocation ratio / share of energy from the DRES among the Participating Consumers shall be as specified in Appendix-II and shall be used by the Distribution Licensee for energy accounting and billing adjustment, subject to applicable wheeling loss and other charges.

1.9 The RESCO / Power Producer and the Participating Consumers shall not claim any right contrary to the Regulations / Orders of the Commission merely on the basis of this Agreement. In case of any inconsistency, the Regulations / Orders of the Commission shall prevail.

2. Separate RESCO-Consumer Commercial Arrangement

2.1 The tariff and other terms and conditions for supply / allocation of energy to the Participating Consumers by the RESCO / Power Producer from the DRES shall be governed by a separate

bilateral / mutual agreement between the RESCO / Power Producer and the Participating Consumers.

2.2 The Distribution Licensee shall not be responsible for recovery of dues of the RESCO / Power Producer from the Participating Consumers and shall not disconnect any Participating Consumer on the ground of any dispute or default arising under the separate mutual agreement between the RESCO / Power Producer and the Participating Consumers.

2.3 Any dispute between the RESCO / Power Producer and the Participating Consumers arising out of the separate mutual commercial agreement shall be resolved mutually or under the dispute resolution mechanism provided in such agreement and shall not be adjudicated by the Commission or the Distribution Licensee, except where such dispute directly involves interpretation or implementation of the Regulations / Orders of the Commission.

2.4 The execution or termination of the separate mutual agreement between the RESCO / Power Producer and any Participating Consumer shall not affect the obligation of such Participating Consumer to pay the lawful electricity bill, open access charges, banking charges, CSS, AS, electricity duty and other charges payable to the Distribution Licensee under applicable laws.

3. Technical and Interconnection Requirements

3.1 The RESCO / Power Producer shall install / ensure installation of suitable isolation devices, both automatic and manual, prior to connection of the DRES with the distribution system and shall permit access to the DISCOM for operation of such devices, wherever required for repair, maintenance, safety or reliable operation of the distribution system.

3.2 In case of power outage on the Distribution Licensee's system, the DRES shall automatically shut down unless special transfer and isolating capabilities have been installed and approved in accordance with applicable standards and directions of the Distribution Licensee / CEI / Commission.

3.3 The technical specifications of meters, CT/PT units, communication equipment, protection system, inverter, transformer, RMU, cables, breakers and other equipment shall be in compliance with the applicable CEA Regulations, DISCOM standards, Grid Code, Distribution Code and directions of the Commission / CEI / SLDC / GETCO / DISCOM.

3.4 All equipment connected to the distribution system shall comply with relevant Indian Standards / BIS / IEC / IEEE standards and all electrical installations shall comply with applicable safety regulations and technical standards.

3.5 The Distribution Licensee /GETCO /SLDC shall specify the interconnection point, delivery point, metering point, metering arrangement, protection requirements and communication requirements as per the applicable Regulations / Orders of the Commission and the approved procedure for grant of connectivity.

3.6 The RESCO / Power Producer shall adhere to power quality requirements, including harmonics, voltage, frequency, flicker and other parameters as specified under applicable standards and directions of the Commission / CEA / DISCOM.

3.7 The RESCO / Power Producer shall furnish operational data such as voltage, frequency, breaker / isolator position, generation, injection and any other data as may be required by the DISCOM / SLDC / GETCO / Commission and shall provide facilities for online transfer of real-time operational data wherever required.

3.8 The RESCO / Power Producer shall obtain all requisite approvals, including CEI approval, connectivity approval, commissioning certificate, metering approval, safety clearance and other statutory approvals before commissioning / synchronisation of the DRES and shall furnish copies of such approvals to the Distribution Licensee / SLDC / GETCO.

3.9 The RESCO / Power Producer and the Participating Consumers agree that the Distribution Licensee may host information relating to application, registration, connectivity, commissioning and allocation of the DRES on its website / web portal for transparency and administrative convenience.

3.10 The RESCO / Power Producer shall be responsible for safe operation, maintenance and rectification of defects of the DRES up to the delivery point / interconnection point, as applicable, and the Distribution Licensee shall be responsible beyond such point to the extent provided under the Regulations.

3.11 Where the DRES capacity is above 1 MW, the RESCO / Power Producer shall install RTU / communication facility as mandated under the Regulations and directions of the SLDC / GETCO / DISCOM.

4. Safety

4.1 The RESCO / Power Producer shall comply with the Central Electricity Authority (Measures relating to Safety and Electric Supply) Regulations, 2023, as amended from time to time, and all applicable directions of the Chief Electrical Inspector.

4.2 The design, installation, maintenance and operation of the DRES shall be carried out in a manner conducive to the safety of the DRES, the distribution system, the grid, operating personnel, consumers and the public at large.

4.3 If the Distribution Licensee /SLDC/ GETCO/ determines that the DRES causes damage or produces adverse effects affecting other consumers, distribution assets, grid security or safety, the RESCO / Power Producer shall disconnect the DRES immediately upon such direction and rectify the defect at its own cost before reconnection.

4.4 Any change, alteration, modification or addition of capacity in the DRES after availing Virtual Net Metering facility shall be carried out only after obtaining prior written permission from the Distribution Licensee and after submission of necessary test certificates and approvals as may be required.

4.5 The RESCO / Power Producer shall be solely responsible for any accident to human beings / animals or damage to property arising due to back-feeding from the DRES when grid supply is off, to the extent decided by the Chief Electrical Inspector or competent authority.

5. Clearances and Approvals

5.1 The RESCO / Power Producer shall obtain and maintain all necessary approvals, permissions, permits and clearances relating to land / premises, environment, electrical safety, grid connectivity, metering, communication, commissioning, operation and maintenance of the DRES. The Participating Consumers shall provide necessary consumer-level documents, no-dues certificates, consent letters and authorisations as may be required for implementation of the Virtual Net Metering arrangement.

6. Access and Disconnection

6.1 The Distribution Licensee shall have access to metering equipment, communication equipment, protection equipment and disconnecting means of the DRES, both automatic and manual, at all times.

6.2 In emergency or outage situation, where there is no access to any disconnecting means, both automatic and manual, such as a switch or breaker, DISCOM may disconnect service to the premise and in such scenario, the eligible consumer shall not have any right to object or to claim any sum from DISCOM citing such immediate disconnection.

6.3 The Distribution Licensee reserves the right to disconnect the DRES at any time in the event of threat / damage from the DRES to its distribution system, personnel or public safety, without prior notice, subject to applicable Regulations / Orders.

7. Liabilities and Indemnity

7.1 The RESCO / Power Producer shall indemnify and keep indemnified the DISCOM, its officers, employees, directors and agents from all claims, damages, losses, penalties, liabilities and costs arising from the design, installation, operation, maintenance, defect, accident, non-compliance, back-feeding or unsafe operation of the DRES, except to the extent attributable to wilful default or gross negligence of the DISCOM.

7.2 The Participating Consumers shall indemnify the DISCOM against claims, liabilities, penalties and costs arising from consumer-level non-compliance, misrepresentation, unauthorised use, non-payment of lawful charges, incorrect consumer information, or breach of this Agreement attributable to them.

7.3 The DISCOM shall not be liable to the RESCO / Power Producer or the Participating Consumers for any indirect, consequential, incidental, punitive or special damages, including loss of profits, business interruption, loss of contract or loss of goodwill, arising out of this Agreement.

7.4 The RESCO / Power Producer and the Participating Consumers shall remain jointly and severally responsible for compliance with this Agreement to the extent of their respective obligations, without prejudice to the separate commercial arrangement between them.

8. Metering

8.1 Metering arrangement shall be as per the Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006, as amended from time to time, the GERC Regulations / Orders and the approved procedure of the Distribution Licensee.

8.2 The RESCO / Power Producer shall install Special Energy Meter / ABT compliant meter capable of recording energy injection into the grid on 15-minute time block basis under the Virtual Net

Metering mechanism, along with generation meter, check meter and communication facility wherever required.

8.3 Meters shall be installed at the generation point and at the delivery / interconnection point, as specified by the Distribution Licensee. The consumer meters of the Participating Consumers shall be read concurrently with the energy injected / exported from the DRES for the purpose of energy accounting and billing adjustment.

8.4 The RESCO / Power Producer and the Participating Consumers shall bear metering, CT/PT, testing, sealing, communication and related costs as per the applicable Regulations / Orders / estimate of the DISCOM, unless otherwise specified by the Commission.

9. Energy Accounting and Commercial Settlement with DISCOM

9.1 The Distribution Licensee shall undertake meter reading of energy injected / exported from the DRES at the delivery point and of the consumer meters of all Participating Consumers according to the regular billing period concurrently.

9.2 The energy exported or injected into the grid from the DRES under Virtual Net Metering arrangement shall be allocated to the Participating Consumers in accordance with the allocation ratio specified in Appendix-II for offsetting their electricity consumption during the relevant billing period.

9.3 The energy exported or injected from the DRES into the grid during any billing period and made available at the consumption end after accounting for applicable losses shall be adjusted against the energy drawn from the grid by the Participating Consumers, in accordance with the allocation ratio specified in Appendix-II, on a 15-minute time block basis. The difference between the energy injected from the DRES, as available at the consumption point, and the energy consumed by the Participating Consumers in the corresponding 15-minute time block shall be treated as banked energy.

9.4 In case of Participating Consumers other than residential category, credit of such banked energy shall be allowed up to a maximum of thirty percent (30%) of the total energy drawn by the Participating Consumers from the Distribution Licensee during the relevant billing period, subject to payment of applicable banking charges as specified under the GERC Green Energy Open Access Regulations and applicable Orders / Regulations of the Commission.

Such banked energy shall be adjusted within the same billing cycle and shall not be permitted to be carried forward to subsequent billing cycles. Any unutilised banked energy remaining at the end of the billing cycle shall be treated as lapsed energy, except where the Regulations provide otherwise.

9.5 In case of Participating Consumers in the residential category, the energy injected from the DRES and available at the consumption end, as per the allocation ratio specified in Appendix-II, shall be adjusted against the energy drawn from the grid during the same billing cycle without levy of banking charges. Any surplus energy remaining after such adjustment shall be treated as deemed purchase by the concerned Distribution Licensee at Rs. 2.25 per kWh or such other rate as may be specified by the Commission from time to time.

9.6 In case of net drawal of electricity by Participating Consumers from the Distribution Licensee during any billing period after adjustment of exported / injected energy in terms of this Agreement, the Distribution Licensee shall raise bills as per the applicable retail tariff.

9.7 Where the Participating Consumers are under Time-of-Day tariff, banked energy available during peak period shall be allowed to be utilised during peak as well as off-peak period, whereas banked energy available during off-peak period shall be utilised only during off-peak period, subject to the applicable Regulations / Orders of the Commission.

9.8 The injection of energy from the DRES into the grid shall be subject to scheduling, forecasting and deviation settlement requirements as per the GERC (Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources) Regulations, 2019, as amended from time to time, and relevant Orders of the Commission.

9.9 Energy injected prior to commissioning of the DRES shall be treated as inadvertent / lapsed energy and the RESCO / Power Producer / Participating Consumers shall not be eligible to receive any monetary compensation for such inadvertent power.

10. Open Access Charges, Banking Charges, CSS and AS

10.1 The Participating Consumers shall be subjected to wheeling charges, wheeling losses, banking charges, Cross Subsidy Surcharge (“CSS”), Additional Surcharge (“AS”) and other applicable charges as specified under the GERC (Green Energy Open Access) Regulations, 2024, the GERC (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, RE technology-

wise tariff orders and other applicable Orders / Regulations of the Commission, as amended from time to time.

10.2 Banking charges, at the rate decided by the Commission through Regulations / Orders, shall be levied on the quantum of banked energy offset against consumption from the grid during the billing cycle, wherever applicable. Banking charges shall not be levied in case the Participating Consumers under Virtual Net Metering arrangement belong to the residential (RGP) category, subject to the Regulations.

10.3 Since the DRES is owned by a RESCO / third party, CSS and AS shall be payable by the Participating Consumers for consumption of energy from such DRES, unless exempted or reduced under the applicable Regulations / Orders of the Commission.

10.4 Where the Participating Consumers consuming energy from such DRES do not claim the renewable energy attribute and allow the Distribution Licensee to avail the same for RPO compliance, such consumers shall be allowed to claim concession in CSS and AS to the extent specified under applicable Regulations / Orders of the Commission.

10.5 CSS and AS shall be exempted for consumption of energy by residential consumers from non-captive / RESCO-owned DRES if the DRES capacity allocated to such residential consumers does not exceed the aggregate capacity worked out considering 2 kW per participating residential consumer, subject to the Regulations / Orders of the Commission.

10.6 All charges payable to the Distribution Licensee shall be paid by the Participating Consumers / RESCO / Power Producer, as applicable, in accordance with the bill / demand raised by the Distribution Licensee and the applicable Regulations / Orders. The inter se recovery or allocation of such charges between RESCO and Participating Consumers shall be governed by their separate mutual agreement and shall not affect the right of the DISCOM to recover lawful charges.

11. Electricity Duty and Government Levies

11.1 Applicability of electricity duty, tax, cess, fee and other Government levies shall be governed by the Gujarat Electricity Duty Act, 1958, other applicable laws and amendments thereto. The Participating Consumers / RESCO / Power Producer shall be responsible for payment of such duty / levy as applicable under law.

12. Renewable Energy Attribute and RPO

12.1 The renewable energy attribute of the electricity consumed by the Participating Consumers from the DRES shall be treated in accordance with the applicable Regulations / Orders of the Commission.

12.2 Where the Participating Consumers are not Obligated Entities and / or do not wish to use consumption of energy from the DRES for voluntary RPO requirement, the quantum of electricity consumed from the DRES may qualify towards compliance of the Distribution Licensee's RPO, subject to applicable Regulations / Orders.

12.3 Any concession in CSS / AS on account of non-claim of renewable energy attribute by the Participating Consumers and use of such attribute by the Distribution Licensee for RPO compliance shall be governed by the applicable Regulations / Orders of the Commission.

13. Connection Costs and Evacuation Infrastructure

13.1 The required evacuation infrastructure up to the delivery point, including dedicated line, metering, CT/PT, protection, communication, isolators and related equipment, shall be created by the DRES Owner / RESCO at its own cost, unless otherwise specified by the Commission.

13.2 The RESCO / Power Producer and / or the Participating Consumers shall bear all costs relating to setting up, interconnection, evacuation, metering, system strengthening, testing and commissioning of the DRES as per the applicable Regulations / Orders / estimate of the DISCOM.

13.3 Any modification, upgradation or strengthening required in the distribution system for connecting the DRES shall be undertaken and charged in accordance with the applicable Regulations / Orders of the Commission and the approved procedure of the Distribution Licensee.

14. Change in Allocation Ratio / Participating Consumers

14.1 Change in allocation ratio shall be permitted only once in a financial year, subject to intimation to the Distribution Licensee at least one month prior to commencement of the financial year and shall be effective from the beginning of such financial year, subject to approval / acceptance by the Distribution Licensee and applicable Regulations.

15. Lead / Nodal Consumer

15.1 The Participating Consumers shall appoint / nominate one of the Participating Consumers as the Lead / Nodal Consumer for administrative purposes only.

15.2 All communications issued by the Distribution Licensee may be addressed to the Lead / Nodal Consumer and such communication shall be deemed to have been served upon all Participating Consumers. It shall be the responsibility of the Lead / Nodal Consumer to communicate the same to other Participating Consumers.

15.3 The Lead / Nodal Consumer shall not be treated as the owner of the DRES merely by reason of such nomination and such nomination shall not affect the obligations of the RESCO / Power Producer as DRES Owner or the obligations of the Participating Consumers under this Agreement.

16. Dispute Resolution

16.1 All disputes or differences between the Parties arising out of or in connection with this Agreement shall first be attempted to be settled through mutual negotiation promptly, equitably and in good faith.

16.2 Any dispute relating to billing of electricity supplied by the Distribution Licensee and bill amount or consumer grievance against the Distribution Licensee shall be governed by the Consumer Grievance Redressal Forum and Electricity Ombudsman mechanism, wherever applicable.

16.3 Any other issue relating to Regulations and its interpretation shall be decided by the Gujarat Electricity Regulatory Commission in accordance with the applicable procedure.

16.4 Any dispute between the RESCO / Power Producer and the Participating Consumers arising purely out of their separate commercial agreement, including tariff / payment / performance obligations inter se, shall be settled in terms of such agreement and shall not be adjudicated by the DISCOM or the Commission, except to the extent the dispute involves implementation of Regulations / Orders of the Commission.

17. Term and Termination

17.1 The term of this Agreement shall be 25 years or the useful life of the DRES, whichever is earlier, unless terminated earlier in accordance with this clause and the applicable Regulations / Orders.

17.2 The RESCO / Power Producer, the Participating Consumers acting through the Lead / Nodal Consumer, or the DISCOM may terminate this Agreement by giving 90 days prior written notice to the other Parties, subject to settlement of all dues, disconnection formalities, regulatory compliance and approval / acceptance of the Distribution Licensee wherever required.

17.3 Upon termination, the RESCO / Power Producer shall disconnect the DRES from the Distribution Licensee's system in a timely and safe manner and to the satisfaction of the Distribution Licensee.

17.4 Termination of this Agreement shall not affect accrued rights and liabilities of the Parties, including payment of bills, open access charges, banking charges, CSS, AS, electricity duty, penalties, compensation, indemnity and other dues payable up to the date of termination.

18. Governing Law and Jurisdiction

18.1 This Agreement shall be governed by the Electricity Act, 2003, the Gujarat Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 2026, the GERC (Terms and Conditions for Green Energy Open Access) Regulations, 2024, the GERC Supply Code, Distribution Code, applicable CEA Regulations and all other applicable Regulations / Orders / directions, as amended from time to time.

19. Communication facility

The DRES having capacity above 1 MW shall mandatorily install RTU.

Provided that for DRES having capacity less than 1 MW, at the time of installation of DRES, connectivity of such DRES with grid shall be ensured by installation and integration of SIM based Remote Monitoring System with centralized platform in a secured manner as per the Guideline issued by State/ Central Government or its Agency from time to time, as part of compliance requirement.

20. Communication

The names of the officials and their addresses, for the purpose of any communication in relation to the matters covered under this Agreement, shall be as under:

In respect of DISCOM	In respect of RESCO / Power Producer

In respect of the Lead / Nodal Consumer and Participating Consumers: _____

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed by their authorised representatives on the day, month and year first above written.

FOR AND ON BEHALF OF DISCOM	**FOR AND ON BEHALF OF RESCO / POWER PRODUCER**	**FOR AND ON BEHALF OF PARTICIPATING CONSUMERS**
Authorized Signatory Name: Designation: Date: Stamp:	Authorized Signatory Name: Designation: Date: Stamp:	Authorized Signatory Name: Designation: Date: Stamp:
Witnesses: 1. _____ 2. _____	Witnesses: 1. _____ 2. _____	Witnesses: 1. _____ 2. _____

Appendix-I

Details of DRES / RESCO / Power Producer

Name of RESCO / Power Producer / DRES Owner	
Registered Office / Address	
DRES Location/Address	
RE Technology / Source	
DRES Capacity in kW (AC)	
BESS Capacity, if applicable	
GEDA Registration No. and Date	
Voltage Level / Interconnection Point / Delivery Point	
Nearest GETCO 66 kV Sub-station and Dedicated Line Details	

Appendix-II

List of Participating Consumers and Allocation Ratio

Sr. No.	Name of Consumer	Consumer No.	Premises / Address	Name of Sdn/Div/ Circle	Tariff Category	Contract Demand / Sanctioned Load	Voltage Level	Allocation Share / Allocated Capacity	Signature
1									
2									
3									
4									

Appendix-III

Authorisation / Consent for Lead / Nodal Consumer

We, the Participating Consumers listed in Appendix-II, hereby nominate Shri / Smt. / M/s. _____, Consumer No. _____, as Lead / Nodal Consumer for the limited purpose of coordination with the DISCOM and RESCO / Power Producer for implementation of the Virtual Net Metering arrangement. The nomination is for administrative convenience only and shall not absolve any Participating Consumer of its obligations under the Agreement, applicable Regulations and other laws.

Sr. No.	**Name of Consumer**	**Consumer No.**	**Signature**	**Date**
1				
2				
3				
4				

Appendix-IV

Declaration regarding Separate RESCO-Consumer Commercial Arrangement

The RESCO / Power Producer and the Participating Consumers declare that they have entered into / shall enter into a separate mutual agreement covering tariff / payment / commercial terms for supply / consumption of energy from the DRES owned by the RESCO / Power Producer. The DISCOM shall not be responsible for enforcement of such commercial arrangement and shall not be a party to disputes arising therefrom, except to the limited extent of implementation of the Regulations, metering, wheeling, energy accounting and recovery of lawful charges payable to the DISCOM.

Appendix-V

Documents / Technical Details to be submitted

1. GEDA registration certificate / certificate from agency designated by Government of Gujarat;
2. Connectivity approval / in-principle consent / final connectivity approval;
3. CEI approval, single line diagram;
4. Meter / CTPT testing certificate from NABL accredited laboratory;
5. Protection scheme, relay details, anti-islanding certificate and synchronisation details;
6. Technical certificates / IEC / BIS compliance documents for major equipment;
7. No-dues certificates / consumer consent letters / lead consumer authorisation;
8. Details of dedicated evacuation line, interconnection point and delivery point;
9. BESS details, if applicable;
10. Any other document required by DISCOM / GETCO / SLDC / GEDA / CEI / Commission time to time, as part of compliance requirement.

DRAFT GUJARAT ELECTRICITY GRID CODE, 2026

GUJARAT ELECTRICITY REGULATORY COMMISSION

PREAMBLE

The Gujarat Electricity Grid Code (GEGC) are Regulations made by the Gujarat Electricity Regulatory Commission in exercise of powers conferred under Sections 181, 39, 40, 42 and 86(1-h) of the Electricity Act, 2003 (Act 36 of 2003) and under Section 42 (b) of the Gujarat Electricity Industry (Reorganizations and Regulation) Act, 2003 (Gujarat Act 24 of 2003) and all powers enabling it in that behalf. The GEGC also lays down the rules, guidelines and standards to be followed by various persons and participants in the system to plan, develop, maintain and operate the power system, in the most secure, reliable, economic and efficient manner, while facilitating healthy competition in the Generation, Transmission and supply of electricity.

NOTIFICATION

In exercise of the powers conferred under Section 86(h) of the Electricity Act, 2003 (Act 36 of 2003) and under Section 42 (b) of the Gujarat Electricity Industry (Reorganizations and Regulation) Act, 2003 (Gujarat Act 24 of 2003), and all powers enabling it in that behalf, the Gujarat Electricity Regulatory Commission hereby notifies this "GUJARAT ELECTRICITY GRID CODE-2026" hereafter called the Grid Code. This Grid Code is applicable for the Gujarat State power grid only. For the inter-State transmission network, the Indian Electricity Grid Code notified by the Central Electricity Regulatory Commission, as amended from time to time, shall be applicable.

Short title, extent and commencement

(1) These Regulations shall be called the Gujarat Electricity Regulatory Commission (Gujarat Electricity Grid Code) Regulations, 2026;

(2) These Regulations shall come into force from date of their publication in the Official Gazette;

(3) These Regulations shall supersede the Gujarat Electricity Grid Code, 2013, dated 16th July 2013.

ABBREVIATIONS

A	
A	Ampere
ABCB	Air Brake Circuit Breaker
ABT	Availability Based Tariff
AC	Alternating Current
ACE	Area Control Error
ALDC	Area Load Despatch Centre
ATC	Available Transfer Capability
AUFLS	Automatic Under Frequency Load Shedding
AVR	Automatic Voltage Regulator
B	
BESS	Battery Energy Storage System
BIS	Bureau of Indian Standards
C	
CBIP	Central Board of Irrigation and Power
CCGT	Combined Cycle Gas Turbine
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CERT	Computer Emergency Response Team
CGP	Central Generation Plant
COD	Commercial Operation Date
CPP	Captive Power Plant
CT	Current Transformer
CTU	Central Transmission Utility
CVT	Capacitive Voltage Transformer
D	
DAS	Data Acquisition System
D/C	Double Circuit
DGVCL	Dakshin Gujarat Vij Company Limited
DISCOMs	Distribution Companies
DSM	Demand Side Management
E	
EFR	Earth Fault Relay
EHT	Extra High Tension
EHV	Extra High Voltage equal to and greater than 66 kV

EMT	Electro Magnetic Transient
EPS	Electric Power Survey
F	
FACTS	Flexible AC Transmission System
FOR	Forum of Regulators
FSC	Fixed Series Capacitor
G	
GEDA	Gujarat Energy Development Agency (GEDA) is the nodal agency for Development of renewable energy sources in Gujarat
GEGC	Gujarat Electricity Grid Code
GERC	Gujarat Electricity Regulatory Commission
GETCO	Gujarat Energy Transmission Corporation Limited
GoG	Government of Gujarat
GPS	Global Positioning System
GSECL	Gujarat State Electricity Corporation Limited
GUVNL	Gujarat Urja Vikas Nigam Limited
H	
HV	High Voltage
HVDC	High Voltage Direct Current
HVRT	High Voltage Ride through
Hz	Hertz
I	
ICT	Inter Connecting Transformer
ID	Induced Draft
IDMT	Inverse Definite Minimum Time
IEC	International Electro-Technical Commission
IEC Standard	Standard approved by International Electro-technical Commission
IEEE	Institution of Electrical and Electronic Engineers Inc. USA
IEGC	Indian Electricity Grid Code
IEM	Interface Energy Meters
IPP	Independent Power Producer
IS	Indian Standards
ISGS	Inter State Generating Station
ISTS	Inter State Transmission System
K	
KHPS	Kadana Hydro Power Station
kV	Kilo Volt

kVA	Kilo Volt Ampere
kVAh	Kilo Volt Ampere Hour
kVAr	Kilo Volt Ampere Reactive
kVArh	Kilo Volt Ampere Reactive Hour
kWh	Kilo Watt Hour
L	
LBB	Local Breaker Backup
LCP	Line Clear Permit
LCR	Line Clear Requisition
LILO	Loop in Loop out
LPS	Late Payment Surcharge
LTOA	Long-Term Open Access
LVRT	Low Voltage Ride through
M	
MCR	Maximum Continuous Rating
MGVCL	Madhya Gujarat Vij Company Limited
MNRE	Ministry of New and Renewable Energy Sources
MOCB	Minimum Oil Circuit Breaker
MPP	Mega Power Project
MTOA	Medium Term Open Access
MU	Million Unit
MVA	Mega Volt Ampere
MVAh	Mega Volt Ampere Hour
MVAr	Mega Volt Ampere Reactive
MVArh	Mega Volt Ampere Reactive Hour
MW	Mega Watt
MWH	Mega Watt Hour
N	
NLDC	National Load Despatch Centre
NPCL	Nuclear Power Corporation Limited
NPC	Nuclear Power Corporation
NTPC	National Thermal Power Corporation
O	
OA	Open Access
OCR	Over Current Relay
OEM	Original Equipment Manufacturer
OLTC	On Load Tap Changer

O&M	Operation and Maintenance
P	
PCC	Protection Coordination Committee
PDC	Phasor Data Concentrator
PGCIL	Power Grid Corporation of India Limited
PGVCL	Paschim Gujarat Vij Company Limited
PLCC	Power Line Carrier Communication
PLF	Plant Load Factor
P_{max}	Maximum Active Power
PMU	Phasor Measurement Unit
PMGS-NMP	Prime Minister Gati Shakti National Master Plan
PPA	Power Purchase Agreement
POD	Power Oscillation Damping
PRAS	Primary Reserve Ancillary Service
PRM	Planning Reserve Margin
PSSs	Power System Stabilizers
PTCC	Power and Telecommunication Co-ordination
R	
RE	Renewable Energy
REA	Regional Energy Account
REGS	Renewable Energy Generating Station
RLDC	Regional Load Despatch Centre
RLNG	Regasified Liquefied Natural Gas
RPC	Regional Power Committee
RTU	Remote Terminal Unit
S	
S/C	Single Circuit
SCADA	Supervisory Control and Data Acquisition
SCED	Security Constrained Economic Despatch
SCUC	Security Constrained Unit Commitment
SEA	State Energy Account
SEZ	Special Economic Zone
SF6	Sulphur Hexa Fluoride
SGS	State Generating Station
SLD	Single Line Diagram
SLDC	State Load Despatch Centre
SOCC	State Operation Coordination Committee

SPS	System Protection Schemes
SRAS	Secondary Reserve Ancillary Service
SSP	Sardar Sarovar Project
SSR	Sub-Synchronous Resonance
STOA	Short-Term Open Access
STU	State Transmission Utility
SVC	Static VAr Compensator
T	
TCSC	Thyristor Controlled Series Capacitor
TOV	Temporary Over Voltage
TPL-A	Torrent Power Limited-Ahmedabad
TPL-S	Torrent Power Limited-Surat
TRAS	Tertiary Reserve Ancillary Service
TRM	Transmission Reliability Margin
TSA	Transmission Service Agreement
TTC	Total Transfer Capability
U	
UGVCL	Uttar Gujarat Vij Company Limited
UHPS	Ukai Hydro Power Station
UI	Unscheduled Interchange
UMPP	Ultra Mega Power Project
USD	unit shut down
V	
VSC	Voltage source convertor
VT	Voltage Transformer
W	
WAMS	Wide Area Measurement System
WRLDC	Western Regional Load Despatch Centre
WRPC	Western Regional Power Committee

1 Introduction

1.1. Overview

The Gujarat Government, in exercise of powers conferred by sub-section (1) of Section (39) of the Electricity Act, 2003 notified the Gujarat Energy Transmission Corporation Ltd. as the State Transmission Utility (STU) with effect from 1st June 2004 as per GoG NotificationNo. GHU-2004-31-GEB-1104-2946-K dated 29th May 2004. Accordingly, Gujarat Energy Transmission Corporation Limited (GETCO) undertakes transmission activities and business as STU. As per sub-Section (2) of Section 39 of the Electricity Act, 2003, following are the functions of the State Transmission Utility:

(a) To undertake transmission of energy through the intra-State transmission system

(b) To discharge all functions of planning and coordination relating to intra-State transmission system with

(i) Central Transmission Utility

(ii) State Governments

(iii) Generating Companies

(iv) Regional Power Committee

(v) Authority

(vi) Licensees

(vii) Any other person notified by the State Government in this behalf.

(c) To ensure development of an efficient, coordinated and economical system of intra- State transmission lines for smooth flow of electricity from a generating station to load centres;

(d) To provide non-discriminatory open access to its transmission system for use by-

(i) any licensee or generating company on payment of the transmission charges; Or

(ii) any consumer as and when such open access is provided by the Commission under sub-section (2) of section 42, on payment of the transmission charges and a surcharge thereon, as may be specified by the Commission.

As per sub-Section (2) of Section 31 of the Electricity Act, 2003, the State Load Despatch Centre (SLDC) shall be operated by a Government Company/ any authority or the State Government may notify corporation established or constituted by or under any State Act. Until the State Government notifies a Government Company or any authority or corporation, the State Transmission Utility shall operate the State Load Despatch Centre. As per sub-Section (2) of Section 32 of the Electricity Act, 2003, the following are the functions of State Load Despatch Centre:

(a) Be responsible for optimum scheduling and despatch of electricity within the State, in accordance with the contracts entered into with the licensees or the generating companies operating in the State;

(b) Monitor the grid operations;

(c) Keep accounts of the quantity of electricity transmitted through the State grid;

(d) Exercise supervision and control over the intra-State transmission system;

(e) be responsible for carrying out real time operations for grid control and despatch of electricity within the State through secure and economic operation of the State grid in accordance with the grid standards and the State Grid Code.

(f) Further, the SLDC and licensees shall comply and ensure compliance of directions that the Regional Load Despatch Centre may give from time to time in connection with the integrated grid operation of the power system or otherwise in regard to matter which affect the operation of the Inter-State Transmission System.

(g) The hydroelectric generating stations of GSECL (KHPS and UHPS) shall be treated in a very special manner for scheduling and despatch (as these plants are operated in coordination with the irrigational requirements).

In order to perform the above task as well as the requirements as stipulated in Clause (h) of Sub-Section (1) of Section 86 of the Electricity Act, 2003 and Clause (m) of Section 17 of Gujarat Act No. 24 of 2003; viz. Gujarat Electricity Industry (Reorganization and Regulation) Act 2003, the Gujarat Electricity Regulatory Commission has formulated the GUJARAT ELECTRICITY GRID CODE; hereinafter referred as the Grid Code applicable for the Gujarat Power System.

1.2. Scope and Extent of Application

1. These Regulations shall apply to all Users of Gujarat Power System including SLDC, State Transmission Utility, Transmission licensees, Distribution licensees and Qualified Coordinating Agencies to the extent applicable.

2. The Grid Code is designed to facilitate the development, operation and maintenance of an efficient, coordinated and economical Gujarat power grid by specifying to STU / transmission licensees and all the Users connected to that system for their technical and procedural obligations. It seeks to be non-discriminatory and ensure that interfaces are not areas of weakness in the supply chain.

1.3. Objectives:

1. To clearly define the roles, responsibilities and functions of all key institutions involved in grid operation and management in Gujarat.
2. To ensure coordinated planning and operation of the intra-State transmission system among all stakeholders.
3. To establish a framework for integrated resource planning encompassing demand forecasting, generation adequacy, and transmission planning for facilitating secure grid operations.
4. To ensure safe, reliable and secure operation of the Gujarat Grid through compliance with prescribed technical and design standards for connectivity.
5. To ensure non-discriminatory treatment of all Users seeking connection to the Gujarat Grid.
6. To ensure that new or modified connections neither suffer nor impose unacceptable effects on the grid or any other connected user.
7. To establish a transparent and standardized procedure for connectivity so that prospective users are aware of the requirements in advance.

8. To mandate fulfilment of technical, protection, metering, communication and cyber security requirements prior to energization of any new or modified power system element.
9. To facilitate seamless integration of renewable energy sources including Wind, Solar, Hybrid and Battery Energy Storage Systems into the grid.
10. To define the minimum protection requirements for any equipment connected to the State Transmission System and thereby minimize the disruption due to faults.
11. To ensure safe and reliable integration of new generating stations and transmission elements into the Gujarat Grid prior to declaration of Commercial Operation Date (COD);
12. To lay down uniform procedures for drawal of start-up power and injection of infirm power during the commissioning period, ensuring grid security is not compromised at any stage;
13. To prescribe standardised trial run requirements for all categories of generating stations, viz., thermal, hydro, solar, wind, energy storage, pumped storage, and hybrid systems, so that all Users are treated in a non-discriminatory and transparent manner;
14. To specify the technical documents, OEM certificates, and performance tests that must be successfully completed and submitted to SLDC before a Certificate of Commercial Operation is granted to any generating company or transmission licensee;
15. To ensure that any generating unit or transmission element, when commissioned, neither suffers unacceptable technical deficiencies nor imposes adverse effects on the operation of the Gujarat Grid or on any other connected User;
16. To ensure safe, reliable and integrated operation of the Gujarat Grid by defining clear roles and responsibilities of SLDC, STU, generating stations, distribution licensees, QCAs, ESS and all other connected entities in coordinating grid operations at all times;
17. To define control hierarchy for frequency management, thereby ensuring grid frequency is maintained within the allowable band at all times;
18. To prescribe procedures for demand management, over-drawal management and load crash situations, so as to protect grid security under stressed conditions;

19. To lay down system security protocols covering isolation of grid elements, voltage and reactive power management, system protection schemes and real-time classification of the power system into Normal, Alert, Emergency, Extreme Emergency and Restorative states;
20. To specify procedures for system restoration following partial or total blackout, including black start operations, mock drills, islanding schemes and post-disturbance analysis for the fastest possible grid recovery;
21. To prescribe continuous monitoring of generation output and scheduled drawal, metering, data communication, SCADA, WAMS, event reporting and periodic testing of power system elements, thereby ensuring transparency, grid discipline and accountability among all Users.
22. To establish a framework for flexible operation of coal/lignite-based thermal generating units to enable reliable, secure and economical grid operation by allowing operation at lower technical minimum levels and enhanced ramping capabilities, while ensuring proper scheduling, compensation, and operational safeguards.
23. To establish a structured framework for optimum scheduling and despatch of electricity for all intra-State entities generators, DISCOMs, ESS, open access consumers and captive generators on a 15-minute time block basis, covering long-term, medium-term, short-term and real-time transactions;
24. To define the control area jurisdiction of SLDC, and lay down the roles and responsibilities of SLDC, generating stations, QCAs, ALDCs and DISCOMs in the declaration of capacity, submission of requisitions and preparation of day-ahead and intra-day despatch and drawal schedules;
25. To prescribe procedures for Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Despatch (SCED), ensuring optimal utilisation of generation resources, maintenance of adequate reserves and minimisation of Area Control Error within the State control area;
26. To specify ramping rates, minimum turndown levels, hydro energy optimisation, margins for primary response and provisions for Unit Reserved Shutdown, so as to ensure technically feasible and grid-secure scheduling at all times;

27. To lay down the procedure for revision of schedules on account of forced outages, grid disturbances, transmission constraints and real-time market transactions, including scheduling from alternate sources of power to honour supply obligations to beneficiaries;
28. To prescribe the framework for energy metering, interface energy accounting, State Energy Account, and deviation settlement mechanism, along with reactive power and VAr charge accounting, ensuring transparent and timely commercial settlement among all pool members.
29. To specify the principles of safety as prescribed in the prescribed in the Central Electricity Authority (Measures Relating to Safety and Electric Supply) Regulations, 2023, when working across a control boundary between the STU/ Transmission Licensee and the Users.
30. To ensure safety to the working personnel of STU/ Transmission Licensee and users and maintenance of proper records for the issue of Line Clear Permits for allowing working personnel to carry out the works.
31. To define the minimum acceptable communication and data acquisition requirements to enable STU/ Transmission Licensee to manage the Transmission System in a safe and economic manner, consistent with the requirements of his license.
32. To define the incident to be reported, the reporting route to be followed and the information to be exchanged between Users to ensure a consistent approach to the reporting of incidents and accidents on the Transmission System.

1.4. Structure of the Grid Code

The structure of the Grid Code is as follows:

1. **Introduction:** This Chapter outlines the broad features of the Grid Code.

2. **Definitions:** The various terms used in the Grid Code are defined under this Chapter.

3. **Management of Grid Code and role of various organizations:** The Grid Code is a live document and has to be periodically reviewed, as and when required, in the light of experience gained. This Chapter formulates the procedures for the same.

4. **Resource planning Code:** This Chapter specifies the technical and design criteria and the procedures to be applied by the State Transmission Utility and other Users for planning and development of the power system.

5. **Connection Code**: This Chapter specifies the technical criteria and standards to be complied with by STU, transmission licensees, the generating companies, distribution licensees and other Users connected or seeking connection to the transmission system.

6. **Protection Code:** This Chapter specifies the protection protocol, protection settings and protection audit plan of electrical systems complied with by STU, transmission licensees, the generating companies, distribution licensees and other Users connected or seeking connection to the transmission system**.**

7. **Commissioning and Commercial Operation Code:** This Chapter covers aspects related to (i) drawal of startup power from and injection of infirm power into the grid, (ii) trial run operation (iii) documents and tests required to be furnished before declaration of COD, (iv) requirements for declaration of COD.

8. **System Operation Code:** This Chapter covers aspects related to operational planning for secure and reliable grid operation of the State grid. This Chapter specifies operating philosophy of the grid, system security, frequency controls and reserves, operational planning, outage planning. Operational planning study, system restoration, real-time operation, demand and load management, post-dispatch analysis, reactive power management and periodic testing of power system elements.

9. **Flexible operation of coal based thermal power generating units:** This Chapter covers aspects of Minimum power level capabilities of coal based thermal power generating units for flexible operation and Ramp rates capabilities of coal based thermal power generating units for flexible operation.

10. **Scheduling and Despatch Code:** This Chapter deals with the procedure for scheduling injection and drawal of power by the intra-State entities for intra-State transactions and the modalities for exchange of information, including scheduling for intra-State entities transacting power through the Inter-State Transmission System through collective and bilateral

transaction. It also covers provisions with respect to control area jurisdiction.

11. **Safety**

Cross Boundary Safety: This Chapter specifies the requirements for safe working practices for maintenance of equipment associated with cross-boundary operations and also the procedure to be followed when the work is carried out on electrical equipment connected to another user's system**.**

Safety and Line Clear Permits: This Chapter sets out the procedure for recording of Line Clear Permits and guidelines for ensuring safety from electrical hazards to the consumers, general public and working personnel.

12. **Communication and Data Acquisition:** This Chapter specifies the minimum requirements of communication and data acquisition facilities to be provided by each user at connection points/ interface points and cross-boundary circuits.

13. **Operational Event and Incident/Accident Reporting:** This Chapter specifies the details of minimum requirement for the exchange of information relating to operations and/or events in the total system, including the Western Grid, which may have an operational effect on:

    a. The Gujarat power grid in case of an operation and/or event occurring on a usersystem,

    b. A user system in the case of an operation and/or event occurring in the TransmissionSystem.

    The procedure for issue of warnings in the event of a risk of serious and widespread disturbance on the whole or part of the Gujarat State power grid is set out in this Chapter.

14. **Monitoring and Compliance Code** This Chapter deals with (a) monitoring of compliance of these Regulations by various entities in the grid by STU, SLDC, SOCC or any other person, (b) manner of reporting the instances of violations of these Regulations and (c) taking remedial steps or initiating appropriate action.

15. **Miscellaneous.** This chapter deals with the miscellaneous aspects such as the power to relax, the power to remove difficulties etc., and other miscellaneous provisions.

1.5. Implementation and Operation of the Grid Code

1. The State Transmission Utility / Transmission Licensees / SLDC shall be responsible for implementation of the Grid Code. All Users shall comply with the Grid Code and assist the State Transmission Utility / SLDC / Transmission Licensees in this regard. The Users must provide all the required information and reasonable rights of access, service and facilities, necessary for implementation of the Grid Code.

2. If any User has any difficulty in complying with any of the provisions of the Grid Code, he shall immediately, without delay, inform the same to the State Transmission Utility as well as the Transmission Licensee concerned, if any, and shall remedy his non-compliance promptly.

3. Consistent failure in compliance with the Grid Code may lead to disconnection of theUser's plant or apparatus. The responsibility for the consequences of disconnection including payment of damages and compensation to consumers rests with the User who consistently violates the Grid Code.

4. Notwithstanding anything contained in these Regulations, the Commission may also Suo-motu or complaint filed by any person, take actions, in case of non-compliance of any provisions of the Grid Code.

1.6. Limitations of the Grid Code

The Grid Code contains procedures for the management of day-to-day technical situations in the power grid, taking into account a wide range of operational conditions likely to be encountered under both, normal and abnormal conditions. The Grid Code cannot foresee all the possible operating conditions. Users must therefore, understand and accept that the SLDC / STU / Transmission Licensees, in such unforeseen circumstances, may be required to act decisively to discharge his obligations, as well as maintain the security of the system. Users shall provide such reasonable cooperation and assistance as the STU/Transmission Licensees may require in such circumstances. The STU/Transmission Licensees / SLDC shall however, refer all such cases for ratification to the Commission.

1.7. Confidentiality

Under the terms of the Grid Code, the STU/ Transmission Licensees/ SLDC will receive information from Users relating to their intentions in respect of their generation or supply businesses. The STU/ Transmission Licensees / SLDC shall not, other than as required by the Grid Code, disclose such information to any other person without the prior written consent of such informant, unless required by Central/State Government departments or any authority.

1.8. Procedures to settle disputes

In the event of any dispute regarding interpretation between any user and STU / Transmission Licensees / SLDC, the matter shall be referred to the Gujarat Electricity Regulatory Commission (Commission). In the event of any conflict between the parties regarding any provision of the Grid Code, the Gujarat Electricity Regulatory Commission will proceed to settle the issue.

1.9. Communication between STU/Transmission Licensee/SLDC and Users

All communications between STU/ Transmission Licensee/ SLDC and Users shall be in accordance with the provision of the Grid Code. Unless otherwise specifically required by the Grid Code, all communication shall be in writing, except where operation time scales require oral communication, in which case, these communications shall be confirmed in writing, as soon as practicable. All the Users shall establish and maintain a reliable communication infrastructure and network for this purpose.

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2 Definitions

Sr. No.	Particulars	Definitions
1.	'Act'	Refers to the Electricity Act, 2003
2.	**'**Active Energy'	Refers to the electrical energy produced, flowing or supplied by an electric circuit during a time interval, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof; i.e., 1000 Wh=1 kWh; 1000 kWh = 1 MWh; 1000 MWh = 1 GWh; 1000 GWh = 1 TWh.
3.	'Active Power'	Refers to the product of voltage and the in-phase component of alternating current measured in units of watts and standard multiples thereof; i.e., 1000 Watts = 1 kW; 1000 kW = 1 MW; 1000 MW = 1 GW; 1000 GW = 1 TW.
4.	'Apparatus'	Refers to all the electrical apparatus like machines, fittings, accessories and appliances, in which electrical conductors are used
5.	'Apparent Power'	Refers to the product of voltage and alternating current measured in units of volt-amperes and standard multiples thereof; i.e., 1000 VA = 1 kVA; 1000 kVA = 1 MVA.
6.	'ALDC'	Refers to the Area Load Management Centre of the Distribution Licensee concerned.
7.	'Alert State'	Means the state in which the operational parameters of the power system are within their respective operational limits, but a single n-1 contingency leads to violation of system security.
8.	'Ancillary Services'	in relation to power system operation, means the services necessary to support the grid operation in maintaining power quality, reliability and security of the grid and includes Primary Reserve Ancillary Service, Secondary Reserve Ancillary Service, Tertiary Reserve Ancillary Service, active power support for load following, reactive power support, black start and such other services as defined in these Regulations.
9.	'Ancillary Services Regulations' or 'AS Regulations'	Means the Central Electricity Regulatory Commission (Ancillary Services) Regulations, 2022, as amended from

		time to time, or the Regulations as may be notified by the Commission for similar purpose.
10.	'Area Control Error' or 'ACE'	Shall be as specified under clause (11) of Regulation 30 of Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2023, as amended from time to time.
11.	'Area of Supply'	Refers to area within which a Distribution Licensee is authorised by his licence to supply electricity.
12.	'Associated Transmission System' or 'ATS'	Augmentation requirement for the existing Intra-State Transmission System which includes transmission system which has been awarded for implementation: Provided further that if any additional transmission system gets awarded for implementation before completion of interconnection study, such additional transmission system shall also be considered as existing InSTS.
13.	'Automatic Generation Control' or 'AGC'	Means a mechanism that automatically adjusts the generation of a control area to maintain its interchange schedule plus its share of frequency response.
14.	'Automatic Voltage Regulator' (AVR)	Means a continuously acting automatic excitation control system to control the voltage of a generating unit measured at the generator terminals.
15.	'Auxiliaries'	Refers to all the plant and machinery required for the generating unit's functional operations that do not form part of the generating unit.
16.	'Auxiliary Energy Consumption'	Auxiliary Energy Consumption' or 'AUX' in relation to a generating station means the quantum of energy consumed by auxiliary equipment of the generating station, such as the equipment being used for the purpose of operating plant and machinery including switchyard of the generating station and the transformer losses within the generating station, expressed as a percentage of the sum of gross energy generated at the generator terminals of all the units of the generating station: Provided that auxiliary energy consumption shall not include energy consumed for the supply of power to the housing colony and other facilities at the generating

		station and the power consumed for construction works at the generating station and integrated mine(s): Provided further that auxiliary energy consumption for compliance with revised emission standards, sewage treatment plant and external coal handling plant (jetty and associated infrastructure) shall be considered separately.
17.	'Availability'	refers to the availability in relation to (i) a thermal generating station/unit and (ii) to a transmission system shall be as mentioned in GERC MYT Regulations, as amended from time to time
18.	'Available Capacity'	Shall have the same meaning as defined in the DSM Regulations of CERC / Orders issued by the Commission as case may be.
19.	'Available Transfer Capability' or 'ATC'	refers to the transfer capability of the inter- control area transmission system available for scheduling commercial transactions (through long term access, medium-term open access and short-term open access) in a specific direction, taking into account the network security. Mathematically, ATC is the Total Transfer Capability less Transmission Reliability Margin
20.	'Backing Down'	Refers to reduction of generation on instructions from SLDC/WRLDC/NLDC by a generating unit under abnormal conditions.
21.	'Beneficiary'	Refers to a person who has a share in an ISGS/SGS or any generating stations.
22.	'Bilateral Transaction'	Means a transaction, other than collective transaction, for exchange of power between a specified buyer and a specified seller directly or through a trading licensee or at a Power Exchange.
23.	'Black Start'	Refers to the procedure necessary for recovery from a total shutdown or partial shutdown without the availability of electricity from external sources.
24.	'Black Start Capability'	refers to an ability in respect of a Black Start Station, for at least one of its generating units or CCGT units to start-up from shutdown and to energise a part of the system and be synchronized to the system upon instruction from the State Load Despatch Centre immediately, without any external supply.

25.	'Black Start Stations'	Refers to generating stations having Black Start Capability.
26.	'Blackout State'	Means a condition at a specific time where a part or all the operations of the power system have got suspended.
27.	'Bulk Consumer'	Means a consumer who avails supply at voltage of 33 kV or above.
28.	'Buyer'	Means a person purchasing electricity through a transaction scheduled with use of Intra-State transmission / distribution system in accordance with applicable Regulations / Orders of the Commission.
29.	'Capacitor'	Refers to an electrical facility provided for generation of reactive power
30.	'Captive Power Plant' (CPP)	Shall have same meaning as defined in the Act.
31.	'CEA Grid Standards'	Means the Central Electricity Authority (Grid Standards) Regulations, 2010, as amended from time to time
32.	'CEA Technical Standards for Communication'	Means the Central Electricity Authority (Technical Standards for Communication System in Power System Operation) Regulations, 2020, as amended from time to time.
33.	'CEA Technical Standards for Connectivity'	Means the Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007, as amended from time to time.
34.	'CEA Technical Standards for Construction'	Means the Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010, as amended from time to time.
35.	'Central Generating Station'	Refers to the generating stations owned by the Companies owned or controlled by the Central Government.
36.	'Central Transmission Utility' or 'CTU'	Means any Government Company, which the Central Government may notify under sub-section (1) of Section 38 of the Act.
37.	'Cold Start'	In relation to steam turbine means start up after a shutdown period exceeding 72 hours (turbine metal temperatures below approximately 40% of their full load values).
38.	'Collective Transaction'	Refers to a set of transactions discovered in Power Exchange through anonymous, simultaneous competitive bidding by buyers and sellers.
39.	'Commission'	Refers to the Gujarat Electricity Regulatory Commission.

40.	'Committee for Intra-State Transmission Planning'	Refers to a committee constituted by the State Government to discuss, review and finalise the proposals for expansion or modification in the Intra-State Transmission System in coordination with CTU.
41.	'Communication System'	means a collection of individual communication networks, communication media, relaying stations, tributary stations, terminal equipment usually capable of inter-connection and inter-operation to form an integrated communication backbone for power sector. It also includes existing communication system of Intra-State Transmission System, Satellite and Radio Communication System and their auxiliary power supply system, etc. used for regulation of inter-State and intra-State transmission of electricity.
42.	'Congestion'	Means a situation where the demand for transmission capacity or power flow on any transmission corridor exceeds its Available Transfer Capability.
43.	'Connection'	Refers to the electric power lines and electrical equipment used to effect a connection of a user's system to the transmission system.
44.	'Connection Conditions'	Refers to those conditions mentioned in Clause 6 of the CEA Grid Connectivity Regulations, which have to be fulfilled before the User's system is connected to the grid.
45.	'Connection Point/ Interface Point'	Refers to an electrical point of connection between the transmission system and the user's system.
46.	'Connectivity'	Refers to the state of getting connected to the inter-State transmission system / intra-State transmission system by a generating station, including a captive generating plant, a bulk consumer or an intra-State transmission licensee / distribution licensee in terms of prevailing applicable Regulations of Commission.
47.	'Connectivity Agreement'	Means an agreement between STU/Distribution licensee and any other person(s) setting out the terms and conditions relating to connection to and/or use of the Intra- State Transmission / Distribution System in terms of prevailing applicable Regulations of the Commission.
48.	'Consumer'	refers to any person who is supplied with electricity for his own use by a licensee or the government or by any other person engaged in the business of supplying electricity to public under the Electricity Act 2003, or any other law for the time being in force and includes any

		person whose premises are for the time being, connected for the purpose of receiving electricity with the works of a licensee, the government or such other person, as the case may be.
49.	'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 in Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2023 as amended from time to time and under these Regulations
50.	'Control Centre'	Includes NLDC or RLDC or REMC or SLDC or Area LDC or Sub-LDC or DISCOM LDC including main and backup Centres, as applicable.
51.	'Control Person'	Refers to a person identified as having technical capability and responsibility for cross boundary safety under Chapter 7, Cross-Boundary Safety of the Grid Code.
52.	'Data Acquisition System' or 'DAS'	Means a system for recording the sequence of operation in time, of the relays or equipment as well as the measurement of pre-selected system parameters.
53.	'Date of Commercial Operation' or 'COD'	Shall have the same meaning as specified under the MYT Regulations as amended from time to time.
54.	'Declared Capacity' or 'DC'	In relation to a generating station means, the capability to deliver ex-bus electricity in MW declared by such generating station in relation to any time-block of the day as defined in these Regulations or whole of the day, duly taking into account the availability of fuel or water and subject to further qualification as per provisions in the relevant regulations.
55.	'Demand'	Refers to the demand for an active power in MW and reactive power in MVAr of electricity, unless otherwise specified.
56.	'Demand Control'	refers to any of the following methods of achieving a Load reduction: (a) Consumer Load Management initiated by Users (b) Consumer Load Reduction by disconnection initiated by Users (other than following an instruction from Load Despatch Centre)

		(c) Consumer Load Reduction instructed by the Load Despatch Centre (d) Automatic Under-frequency Load Disconnection (e) Emergency Manual Load Disconnection
57.	'Demand Response'	Means variation in electricity usage by the end consumers or by a control area manually or automatically, on standalone or aggregated basis, in response to the system requirements as identified by the concerned Load Despatch Centre.
58.	'Despatch Schedule'	Means the ex-power plant net MW and MWh output of a generating station, for a time block, scheduled to be injected to the Grid from time to time.
59.	'Disconnection'	Refers to the physical separation of Users from the Power System.
60.	'Discrimination'	Refers to the quality where a relay or protective system is enabled to pick out and cause to be disconnected only the faulty apparatus.
61.	'Distribution Licensee'	Refers to a Licensee authorised to operate and maintain a distribution system for supplying electricity to the consumer in his area of supply.
62.	'Distribution System'	Refers to the system of wires and associated facilities between the delivery points on the transmission lines or the generating station connection and the point of connection to the installation of the consumers.
63.	'Disturbance Recorder' or 'DR'	Means a device for recording the behaviour of the pre-selected digital and analog values of the system parameters during an event.
64.	'Drawal'	Refers to the import/export of electrical energy from/to the grid.
65.	'Drawal Schedule'	Means the summation of the station-wise ex- power plant drawal schedules from all ISGS/SGS and other stations and drawal from or injection to regional grid under prevailing applicable Regulations.
66.	'Deviation Settlement Mechanism'	Refers to any Deviation Settlement Mechanism and related matters approved by the Commission from time to time.
67.	'Earthing'	Refers to connecting the conducting parts of an equipment or machinery with the general mass of earth, in such a manner ensuring at all times an immediate

		discharge of energy without danger, by maintaining the same efficiency at earth's potential.
68.	'Electricity'	Refers to electrical energy (a) Generated, transmitted, supplied or traded for any purpose: or (b) Used for any purpose except the transmission of a message.
69.	'Electric Line'	Refers to any line which is used for carrying electricity for any purpose and includes, a) any support for any such line, that is to say, any structure, tower, pole or other thing in, on, by or from which any such line is, or may be, supported, carried or suspended; and b) any apparatus connected to any such line for the purpose of carrying electricity;
70.	'Electrical Plant'	Refers to any plant, equipment, apparatus or appliance or any part thereof used for, or connected with, the generation, transmission, distribution or supply of electricity but does not include- (a) an electric line; or (b) a meter used for ascertaining the quantity of electricity supplied to any premises; or (c) an electrical equipment, apparatus or appliance under the control of a consumer;
71.	'Emergency State'	Means the state in which one or more operational parameters are outside their operating limit or many of the equipment connected to the grid are operating above their respective loading limit.
72.	'Energy Charge'	Means the energy charge for the generating stations whose tariffs are determined by the Commission under Section 62 or discovered and adopted by the Commission under Section 63 of the Act.
73.	'Energy Storage System' or 'ESS'	in relation to the electricity system, means a facility where electrical energy is converted into any form of energy which can be stored, and subsequently reconverted into electrical energy and injected back into the grid.
74.	'Entitlement'	Refers to a share of a beneficiary (in MW / MWh) in the installed capacity/output capability of an ISGS / SGS.

75.	'Entity'	Refers to such persons who are in the control area of SLDC / ALDC / LMU and whose metering and energy accounting is done at the State level.
76.	'Event'	Means an unscheduled or unplanned occurrence in the grid including faults, incidents and breakdowns.
77.	'Event Logging Facilities'	Means a device for recording the chronological sequence of operations, of the relays and other equipment.
78.	'Exciter'	Refers to the source of electrical power providing the field current of a synchronous machine.
79.	'Ex-Power Plant'	Means net MW or MWh output of a generating station, after deducting auxiliary consumption and transformation losses.
80.	'Fault Locator' or 'FL'	Means a device installed at the end of a transmission line to measure or indicate the distance at which a line fault may have occurred.
81.	'Flat Frequency Control'	Means a mechanism for correcting ACE by factoring in only the frequency deviation and ignoring the deviation of net actual interchange from net scheduled interchange.
82.	'Flat tie-line control'	Means a mechanism for correcting ACE by factoring in only the deviation of net actual interchange from net scheduled interchange ignoring frequency deviation.
83.	'Flexible Alternating Current Transmission System' or 'FACTS'	means a power electronics-based system and other static equipment that provide control of one or more AC transmission system parameters to improve power system stability, enhance controllability and increase power transfer capability of transmission systems.
84.	'Flexible Operation'	means the ability of coal based thermal power generating units to generate power at specified levels mentioned in these regulations, as per the requirement of the grid.
85.	'Flow-gate'	Means a group of parallel transmission line (s), outage of which may lead to cascade tripping or separation of systems or loss of generation complex or loss of load centre.
86.	'Forced Outage'	Means an outage of a generating unit or a transmission facility due to a fault or any other reasons which have not been planned.

87.	'Free Governor Mode of Operation' or 'FGMO'	Means the mode of operation of governor where machines are loaded or unloaded directly in response to grid frequency, i.e., machine unloads when grid frequency is more than 50 Hz and loads when grid frequency is less than 50 Hz. The amount of loading or unloading is proportional to the governor droop.
88.	'Frequency Response Characteristics' or 'FRC'	Means automatic, sustained change in the power consumption by load or output of the generators that occurs immediately after a change in the load-generation balance of a control area and which is in a direction to oppose any change in frequency. Mathematically it is equivalent to FRC = Change in Power (ΔP) / Change in Frequency (Δf)
89.	'Frequency Response Obligation' or 'FRO'	Means the minimum frequency response a control area has to provide in the event of any frequency deviation.
90.	'Frequency Response Performance' or 'FRP'	Means the ratio of actual frequency response with frequency response obligation.
91.	'Frequency Stability'	Means the ability of the transmission system to maintain stable frequency in the normal state and after being subjected to a disturbance.
92.	'Gate Closure'	Means the time at which the bidding for a specific delivery period closes at the power exchange and no further bidding or modification of already placed bids can take place for the said delivery period.
93.	'Generating Company'	Refers to any company or body corporate or association or body of individuals, whether incorporated or not, or artificial juridical person, which owns or operates or maintains a generating station.
94.	'Generating Station'	refers to any station for generating electricity, including any building and plant with step-up transformer, switchyard, switch gear, cables or other appurtenant equipment, if any used for that purpose and the site thereof, a site intended to be used for a generating station, and any building used for housing the operating staff of a generating station, and where electricity is generated by water – power, includes penstocks, head and tail works, main and regulatory reservoirs, dams and other hydraulic works, but does not in any case include any substation.

95.	'Generating Unit'	a) an unit of a generating station (other than those covered in sub-clauses (b) and (c) of this Regulation) having electrical generator coupled to a prime mover within a power station together with all plant and apparatus at the power station which relate exclusively to operation of that turbo-generator, b) an inverter along with associated photovoltaic modules and other equipment in respect of generating station based on solar photo voltaic technology. c) a wind turbine generator with associated equipment, in respect of generating station based on wind energy; d) in respect of RHGS, combination of hydro generator under sub-clause (a); or solar generator under sub-clause (b) or wind generator under sub-clause (c) of this Regulation
96.	'Generation Schedule'	Refers to the despatch schedule of a generating station.
97.	'Generator Capability Curve'	Refers to a diagram, which shows the MW and MVAr capability limits within which a generating unit will be expected to operate under steady state conditions.
98.	'GNA Grantee'	Means a person who has been granted GNA or is deemed to have been granted GNA under GNA Regulations of CERC.
99.	'Governor Droop'	In relation to the operation of the governor of a generating unit means the percentage drop in system frequency, which would cause the generating unit under governor action to change its output from no load to full load.
100.	'Grid'	Refers to high voltage backbone system of inter-connected transmission lines, substations and generating stations.
101.	'Grid Security'	Means the power system's capability to retain a normal state or to return to a normal state as soon as possible, and which is characterized by operational security limits.
102.	'Grid Standards'	Refers to the Standards specified by the Authority under sub section (d) of the Section 73 of the Act.

103.	'Hot Start'	In relation to steam turbine, means the start up after a shutdown period of less than 10 hours (turbine metal temperatures below approximately 80% of their full load values).
104.	'Indian Standards' (IS)	Refers to those standards and specifications approved by the Bureau of Indian Standards.
105.	'Inertia'	Means the contribution to the capability of the power system to resist changes in frequency by means of an inertial response from a generating unit, network element or other equipment that is coupled with the power system and synchronized to the frequency of the power system.
106.	'Infirm Power'	Means the electricity injected into the grid prior to the date of commercial operation of a unit of the generating station.
107.	'Inter tripping'	Refers to the tripping of circuit breaker by commands initiated from Protection at a remote location independent of the state of local Protection; or operational inter tripping.
108.	'Interconnecting Transformer' (ICT)	Refers to a transformer connecting EHV lines of different voltage systems.
109.	'Intermediary Procurer'	Shall have the same meaning as defined in Electricity (Amendment) Rules, 2022, as amended from time to time.
110.	'Inter-State Generating Station' (ISGS)	Means a central generating station or any other generating station having a scheme for generation and sale of electricity in more than one State.
111.	'Inter-State Transmission System' or 'ISTS'	Refers to Inter-state Transmission System, which includes: Any system for the conveyance of electricity by a main Transmission Line from the territory of one State to another. The conveyance of electricity across the territory of an intervening State as well as conveyance within a State, which is incidental to such inter-State transmission of electricity. The transmission of electricity within the territory of a State; built, owned, operated, maintained or controlled by the Central Transmission Utility.
112.	'Intra-state Transmission System'	Refers to any system for transmission of electricity other than an Inter-State Transmission System.

113.	'Isolation'	Refers to the disconnection of EHV/ HV apparatus from the remainder of the system in which that EHV/ HV Apparatus is situated.
114.	'Licence'	Refers to licence granted under provisions of the Act.
115.	'Licensee'	Refers to a person who has been granted a licence under provisions of the Act.
116.	'Load'	means the active, reactive or apparent power consumed by a utility/installation of consumer
117.	'Load Factor'	Refers to the ratio of the average power to the maximum demand. The load factor depends on the interval of time of the maximum demand and the period over which the average is taken. $\text{Load Factor} = \frac{\text{Units consumed in a given period}}{\text{Maximum Demand x No. of hours in the period}}$
118.	'Long–term Open Access'	Refers to the right to use the intra-State transmission system for a period exceeding 12 years but not exceeding 25 years as specified in prevailing appropriate Regulations of the Commission.
119.	'Main Protection'	Refers to protection equipment or system expected to have priority in initiating either a fault clearance or an action to terminate an abnormal condition in the power system.
120.	'Maximum Continuous Rating' or 'MCR'	Means the maximum continuous output in MW at the generator terminals guaranteed by the manufacturer at rated parameters.
121.	'Medium-term Open Access'	Refers to the right to use the intra-State transmission system for a period exceeding three months but not exceeding three years as specified in prevailing appropriate Regulations of the Commission.
122.	'Merit Order'	Means the order of ranking of available electricity generation in ascending order from least energy charge to highest energy charge to be used for deciding despatch instructions to minimize the overall cost of generation.
123.	'Minimum Turndown Level'	Means the minimum output power expressed in percentage of maximum continuous power rating that the generating unit can sustain continuously; to be on bar and includes minimum power level as defined in CEA (Flexible Operation of Coal based Thermal Power

		Generating Units) Regulations, 2023 as amended from time to time.
124.	'Nadir Frequency'	Means minimum frequency after a contingency in case of generation loss and maximum frequency after a contingency in case of load loss.
125.	'National Load Despatch Centre' or 'NLDC'	Means the Load Despatch Centre established under sub-section (1) of Section 26 of the Act.
126.	'Near Miss Event'	means an incident of multiple failures that has the potential to cause a grid disturbance, power failure or partial collapse but does not result in a grid disturbance.
127.	'Net Drawal Schedule'	Means the drawal schedule of an Intra-State entity, which is the algebraic sum of all its transactions through the Inter / Intra=State transmission system after deducting the transmission losses.
128.	'Normal State'	Means the state in which the operational parameters of the power system are within their respective operational limits and equipment are within their respective loading limits.
129.	'Off-Bar Declared Capability'	Means the difference between Declared Capacity and On-Bar Declared Capacity in MW.
130.	'On-Bar Declared Capacity'	In relation to a generating station means the capability to deliver ex-bus electricity in MW from the units on-bar declared by such generating station in relation to any time block of the day or whole of the day, duly taking into account the availability of fuel and water and subject to further qualification in the relevant Regulations.
131.	'Operating Range'	Refers to the operating range of frequency and voltage as specified under the operating code.
132.	'Operation'	Refers to a scheduled or planned action, relating to the operation of a system.
133.	'Operational Parameters'	Means the parameters for system security as specified by the system operator-damping frequency, voltage at station-bus, angular separation, damping ratio, short circuit level, inertia.
134.	'Out of Synchronism'	Refers to the condition where a system or generating unit cannot meet the requirements to enable it to be synchronized.

135.	'Outage'	Refers to a total or partial reduction in availability due to repair and maintenance of the transmission or distribution or generation facility or defect in the Auxiliary System.
136.	'Overhead line'	means any electric line which is placed above the ground and in the open air, but does not include live rails of traction system;
137.	'Part Load'	Refers to the condition of a generating station, which is loaded, but is not running at its declared availability.
138.	'Partial Shutdown'	Refers to a shutdown of part of the system, resulting in failure of power supply, either from external connections or from the healthy part of the system.
139.	'Person'	Shall include any company or body corporate or association or body of individuals, whether incorporated or not, or artificial juridical person.
140.	'Phasor Measurement Unit'' (PMU)	Means a device which provides phasor information (both magnitude and phase angle) for one or more phases of AC voltage or current waveforms in real time
141.	'Planned Outage'	Refers to an outage of generating plant or part of the transmission system, or part of a user's system coordinated by SLDC.
142.	'Pool Account'	Means Pool Accounts referred to in the prevailing applicable Regulations of the Commission including accounting of following transactions: i. Deviations settlement accounts Ii Ancillary services iii. Reactive energy exchanges iv. congestion charges v. Transmission deviation account
143.	'Pooling Station'	Means the Intra-State grid sub-station where pooling of generation of connected individual generating stations is done for interfacing with the next higher voltage level.
144.	'Power Exchange'	Refers to the power exchange, which has been granted registration in accordance with CERC (Power Market Regulations), 2010, as amended from time to time.
145.	'Power Factor'	Refers to the ratio of Active Power (kW) to Apparent Power (kVA)

146.	'Power System'	"power system" means all aspects of generation, transmission, distribution and supply of electricity and includes one or more of the following, namely :— (a) generating stations (b) transmission or main transmission lines (c) sub-stations (d) tie-lines (e) load despatch activities (f) mains or distribution mains (g) electric supply-lines (h) overhead lines (i) service lines (j) works
147.	'Primary Reserve'	Means the maximum quantum of power, which will immediately come into service through governor action of the generator or frequency controller or through any other resource in the event of sudden change in frequency as, specified in these Regulations or any other applicable Regulations / Orders of the Commission / procedure approved by the Commission.
148.	'Protection'	Refers to the schemes and apparatus for detecting abnormal conditions on a system and initiating fault clearance or actuating signals or indications.
149.	'Qualified Coordinating Agency' or 'QCA'	Means the mutually agreed agency registered with SLDC, to act as a coordinating agency on behalf of wind/solar generators connected to a pooling station / substation and may be one of the generators for scheduling, forecasting, operational coordination and deviation settlement as provided under the Forecasting, Scheduling and Deviation Regulations 2019 of the Commission.
150.	'Ramp Rate'	Means rate of change of a generating station output expressed in % MW per minute.
151.	'Rate of Change of Frequency' or '*df/dt*'	Means the time derivative of the power system frequency, which negates short-term transients and therefore reflects the actual change in synchronous network frequency.
152.	'Rated MW'	Refers to the rating plate MW output of a generating unit, being that output up to which the generating unit is designed to operate.

153.	'Reactor'	Refers to an electrical facility specifically designed to absorb Reactive Power.
154.	'Reactive Power'	Refers to the product of voltage and current and the sine of the phase angle between them, measured in units of volt-amperes reactive and standard multiples thereof; i.e. 1000 Var = 1kVAr, 1000 kVAr = 1 MVAr.
155.	'Reference contingency'	Means the maximum positive power deviation occurring instantaneously between generation and demand and considered for estimation of reserves.
156.	'Regional Energy Account' or 'REA'	means account of energy and other parameters issued by the respective RPC for the purpose of billing and settlement of charges of ISGS and other Users of the concerned region.
157.	'Regional Entity'	Means the entity which is in the RLDC control area and whose metering and energy accounting is done at the regional level.
158.	'Regional Grid'	Means the high voltage backbone system of inter-connected transmission lines, sub-stations and generating plants in a region.
159.	'Regional Load Despatch Centre' or 'RLDC'	Means the Centre established under sub-section (1) of Section 27 of the Act.
160.	'Regional Power Committee' or 'RPC'	"Regional Power Committee" means a committee established by resolution by the Central Government for a specified region for facilitating the integrated operation of the power systems in that region.
161.	'Remote Terminal Unit' or 'RTU'	Means a device suitable for measuring, recording and storing the consumption of electricity or any other quantity related with electrical system and status of the equipment in real time basis and exchanging such information with the data acquisition system for display and control and shall include, wherever applicable, other equipment such as transducers, relays with necessary wiring and accessories
162.	'Renewable Energy Generating Station' or 'REGS'	Means a generating station based on a renewable source of energy with or without Energy Storage System and shall include Renewable Hybrid Generating Station.
163.	'Renewable Hybrid Generating Station' or 'RHGS'	Means a generating station based on hybrid of two or more renewable source(s) of energy with or without Energy Storage System, connected at the same inter-connection point.

164.	'Resilience'	Means the ability to withstand and reduce the magnitude or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, or rapidly recover from such an event.
165.	'Restorative State'	Means a condition in which control action is being taken to reconnect the system elements and to restore system load.
166.	'Re-synchronization'	Refers to the bringing of parts of the system which have gone out of synchronism with each other, back into synchronism.
167.	'Supervisory Control and Data Acquisition' (SCADA)	Refers to the communication links and data processing systems, which provide information to enable implementation of requisite supervisory and control actions.
168.	'Switching over-voltages'	These are over-voltages generated during switching of lines, transformers and reactors etc. having wave fronts of 250/2500 micro sec.
169.	'Secondary Reserve'	Means the maximum quantum of power which can be activated through secondary control signal by which injection or drawal or consumption of an SRAS provider is adjusted in accordance with prevailing applicable Order / Regulations of the Commission / procedure approved by the Commission.
170.	'Secondary Reserve Ancillary Service' or 'SRAS'	Means the Ancillary Service comprising SRAS-Up and SRAS-Down, which is activated and deployed through secondary control signals.
171.	'Secondary Reserve Ancillary Service Provider' or 'SRAS Provider'	Means an entity which provides SRAS-Up or SRAS-Down service in accordance with prevailing applicable Order / Regulations of the Commission / procedure approved by the Commission.
172.	'Security Constrained Economic Despatch' or 'SCED'	Means optimised despatch of generating units subject to operational and technical limits of generation and transmission facilities as specified in these Regulations and procedure approved by the Commission.
173.	'Security Constrained Unit Commitment' or 'SCUC'	Means committing generating units while respecting limitations of the transmission system and unit operating characteristics as specified in these Regulations and procedure approved by the Commission.

174.	'Seller'	Means a person, including a generating station, supplying electricity through a transaction scheduled in accordance with these Regulations.
175.	'Share'	Means percentage or MW entitlement of a beneficiary in an ISGS/SGS either notified by Government of India or agreed between the generating company and beneficiary through contracts and implemented through GNA, TGNA / LTA, MTOA or STOA, as the case may be.
176.	'Short-term Open Access'	Refers to open access for a period up to one month at a time, but not exceeding a period of six months in a calendar year.
177.	'Start-up'	Refers to the action of bringing a generating unit from shut-down to synchronous speed.
178.	'State Energy Account' (SEA)	Refers to a state energy account prepared on monthly basis by the SLDC for the billing and settlement of Capacity Charge and Energy Charge.
179.	'State Load Despatch Centre' or 'SLDC'	Means the Centre established under sub-section (1) of Section 31 of the Act.
180.	'State Transmission Utility' or 'STU'	Means the board or the government company specified as such by the concerned State Government under sub-section (1) of section 39 of the Act;
181.	'Static VAR Compensator' (SVC)	Refers to an electrical facility designed for the purpose of generating or absorbing Reactive Power.
182.	'Station Transformer'	Refers to a transformer supplying electrical power to the auxiliaries of a generating station, which is not directly connected to a generating unit terminal.
183.	'Sub- SLDC'	Refers to one of the three stations in Gujarat State being established under Western Region System Unified Load Despatch Scheme, having as main functions, data acquisition and transfer to SLDC; and supervisory control of load centre in their respective area.
184.	'Substation'	Refers to the station for transforming or converting electricity for the transmission or distribution thereof and includes transformers, converters, switchgears, capacitors, synchronous condensers, structures, cable and other appurtenant equipment and any buildings used for that purpose and the site thereof.
185.	'Supply'	In relation to electricity, means the sale of electricity to a licensee or consumer;

186.	'Synchronized'	Refers to those conditions where an incoming generating unit or system is connected to the busbars of another system so that the frequencies and phase relationships of that generating unit or system as the case may be, and the system to which it is connected are identical.
187.	'System Constraint'	Means a situation in which there is a need to prepare and activate a remedial action in order to respect operational security limits.
188.	'System State'	Means the operational state of the power system in relation to the operational security limits which can be normal state, alert state, emergency state, extreme emergency state and restorative state.
189.	'Tariff Regulations' or 'MYT Regulations'	Means the Tariff Regulations notified by the Commission from time to time under the provisions of the Act.
190.	'Tertiary Reserve'	Means the quantum of power which can be activated in order to take care of contingencies and to cater to the need for replacing secondary reserves.
191.	'Temporary Over-voltages'	These are power frequency over-voltages produced in a power system due to sudden load rejection, single phase to ground faults, etc.
192.	'Tie-line bias control'	Means a mechanism of correcting Area Control Error (ACE) by factoring in deviation of net actual interchange from net scheduled interchange as well as frequency deviation.
193.	'Time Block'	Means block of duration as specified by the Commission for which energy meters record values of specified electrical parameters with first time block starting at 00.00 Hours, presently of fifteen/five (15/5) minutes duration.
194.	'Total Transfer Capability' (TTC)	Refers to the amount of electric power that can be transferred reliably over the inter-control area transmission system under a given set of operating conditions considering the effect of occurrence of the worst credible contingency.
195.	'Transmission Licensee'	Refers to a licensee authorised to establish and operate transmission lines. (A license granted under Section 14 of the Act to transmit electricity).

196.	'Transmission Lines'	Refers to all high pressure cables and overhead lines (not being an essential part of the distribution system of a licensee) transmitting electricity from a generating station to another generating station or a substation, together with any step- up and step-down transformers, switch-gear and other works necessary to and used for the control of such cables or overhead lines, and such buildings or part thereof as may be required to accommodate such transformers, switch-gear and other works.
197.	'Transmission Planning Criteria'	Means the criteria issued by CEA for transmission system planning time to time.
198.	'Transmission Reliability Margin' (TRM)	Refers to the amount of margin kept in the total transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.
199.	'Transmission System'	Refers to the system consisting of high-pressure cables and overhead lines of the Transmission Licensee for transmission of electrical power from the generating station up to Connection Point/ Interface Point with the distribution system. This shall not include any part of the distribution system.
200.	'Trial Operation' or 'Trial Run'	Shall have the same meaning as specified under these Regulations, as applicable.
201.	'Under Frequency Relay'	Refers to an electrical measuring relay intended to operate when its characteristic quantity reaches the relay settings by decrease in frequency.
202.	'User'	Means and includes generating company, captive generating plant, energy storage system, transmission licensee including deemed transmission licensee, distribution licensee, deemed distribution licensee, RE project / park developer, ESS or bulk consumer which is or whose electrical plant is connected to the State grid.
203.	'Voltage Stability'	Means the ability of a transmission system to maintain steady acceptable voltages at all nodes in the transmission system in the normal situation and after being subjected to a disturbance.
204.	'WAMS'	Refers to a system, comprising of phasor measurement unit (PMUs) and the integrated data communication system for collecting various power system including the amplitude, phase angle of the various power system

		parameters like voltage, power flow, frequency from multiple locations on the power system and extract the dynamics characteristics of the system from the data easily and with high degree of accuracy.
205.	'Wheeling'	"Wheeling" means the operation whereby the distribution system and associated facilities of a transmission Licensee or distribution Licensee, as the case may be, are used by another person for the conveyance of electricity on payment of charges to be determined under section 62 of the Electricity Act 2003;
206.	'Warm Start'	Means the start up after a shutdown period between 10 hours and 72 hours (turbine metal temperatures between approximately 40% to 80% of their full load values) in relation to steam turbine.
207.	'Works'	Includes electric line, and any building, plant, machinery, apparatus and any other thing of whatever description required to transmit, distribute or supply electricity to the public and to carry into effect the objects of a license or sanction granted under this Act or any other law for the time being in force.
208.	'WS Seller'	shall have the same meaning as prescribed in IEGC.

Words and expressions used and not defined in these Regulations but defined in the Acts shall have the meanings assigned to them in the said Acts. Expressions used herein, but not specifically defined in these Regulations or in the said Acts but defined under any law passed by a competent legislature and applicable to the electricity industry in the state shall have the meaning assigned to them in such law. Subject to the above, expressions used herein but not specifically defined in these Regulations or in the Acts or any law passed by a competent legislature shall have the meaning as is generally assigned in the electricity industry.

Interpretation

In the interpretation of these Regulations, unless the context otherwise requires:

- Words in the singular or plural term, as the case may be, shall also be deemed to include the plural or singular term, respectively;
- the terms include or including shall be deemed to be followed by without limitation or but not limited to regardless of whether such terms are followed by such phrases or words like "import";

- References herein to the code shall be construed as a reference to these Regulations, as amended or modified by the GERC, from time to time, in accordance with the applicable laws in force;
- The headings are inserted for convenience and may not be taken into account for the purpose of interpretation of these Regulations;
- References to any statutes, Regulations or guidelines shall be construed as including all statutory provisions consolidating, amending or replacing such statutes, Regulations or guidelines, as the case may be, referred to.

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3 Role of Various Organizations

3.1 Role of STU

1. Section 39 of the Electricity Act, 2003, stipulates that the functions of the State Transmission Utility (STU) shall be:

   (a) To undertake transmission of electricity through the intra-State transmission system;

   (b) To discharge all functions of planning and coordination relating to intra-Statetransmission system with

      i) Central Transmission Utility

      ii) State Government

      iii) Generating companies

      iv) Regional Power Committees

      v) Authority

      vi) Licensees

      vii) Any other person notified by the state in this behalf;

   (c) To ensure development of an efficient, coordinated and economical system of intra-State transmission lines for smooth flow of electricity from a generating station to the load centres;

   (d) To provide non-discriminatory open access to its transmission system for use by:

      (i) Any licensee or generating company on payment of the transmission charges; or

      (ii) Any consumer as and when such open access is provided by the State Commission under sub-section (2) of section 42 of the Act, on payment of the transmission charges and a surcharge thereon, as may be specified by the State Commission.

2. Until a government company or any authority or corporation is notified by the State Government, the State Transmission Utility shall operate the State Load Despatch Centre.

3.2 Role of SLDC

In accordance with Section 32 of the Act, the State Load Despatch Centre (SLDC) shall have following functions:

(1) The State Load Despatch Centre shall be the apex body to ensure integrated operation of the power system in the State.

(2) The State Load Despatch Centre shall -

(a) be responsible for optimum scheduling and despatch of electricity within the State, in accordance with the contracts entered into with the licensees or generating companies operating in the State;

(b) Monitor grid operations;

(c) Keep accounts of the quantity of electricity transmitted through the State grid;

(d) Exercise supervision and control over the intra-State transmission system;

(e) Be responsible for carrying out real time operations for grid control and despatch of electricity within the State through secure and economic operation of the State grid in accordance with the grid standards and the State Grid Code.

(3) The following are contemplated as exclusive functions of SLDC:

(a) System operation and control of the State grid covering contingency analysis and operational planning on real time basis;

(b) Scheduling / re-scheduling of generation;

(c) System restoration following grid disturbances;

(d) Metering and data collection;

(e) Compiling and furnishing data pertaining to system operation;

(f) Operation of State UI pool account, State Reactive Energy account and other functions as directed by the Commission.

(4) In accordance with Section 33 of the Act, the State Load Despatch Centre in a State may give such directions and exercise such supervision and control as may be required for ensuring the integrated grid operations and for achieving the maximum economy and efficiency in the operation of power system in that State. Every licensee, generating company, generating station, substation and any other person connected with the operation of the power system shall comply with the directions issued by the State Load Despatch Centre under subsection (1) of Section 33 of the Act. The State Load Despatch Centre shall comply with the directions of the Regional Load Despatch Centre.

(5) In case of inter-State bilateral and collective short-term open access transactions having a State utility or an intra-State entity as a buyer or seller, SLDC shall accord concurrence or no objection or a prior standing clearance, as the case may be, in accordance with the applicable CERC and GERC Regulations.

3.3 Role of Sub-SLDC

Three Sub-SLDCs at Gandhinagar, Jambuva and Jetpur in Gujarat State have been established having main functions of data acquisition and transfer to SLDC, supervisory control of load centre in their respective area, as well as the following functions:

(1) The Sub-SLDC shall assist SLDC to ensure integrated operation of the power systemin the State;

(2) The Sub-SLDC shall assist SLDC for monitoring grid operations;

(3) The Sub-SLDC shall assist SLDC for supervision and control over the intra-Statetransmission system within their area.

(4) The Sub-SLDC shall assist SLDC for integration and Monitoring of RTU and PMU data in their respective control area.

3.4 Role of Distribution System Operator (DSO)

1. Plan and coordinate resources in real time to manage the distribution system. Providing real-time information of consumption to customers. Integrating of distributed renewable energies.

2. Enabling demand response mechanisms: DSOs send data about their network and consumption or generation at connected sites to RTE.

3. Providing incentives for distributed energy generation: DSOs can create a market for wholesale-distributed generation.

4. Coordinating local constraint prices: DSOs coordinate local constraint prices with those of the TSO.

5. Coordinated planning of Communication Infrastructure

6. RE forecasting, scheduling and deviation settlement,

7. Congestion management in distribution network

8. Providing appropriate signals to the LDCs on the technical needs of the distribution system.

9. Separation of Wire business & supply business

10. Creating platform for existing and new players, Prosumers, iDSOs (independent DSOs), Data Management Operators, (DMOs), Distribution Network Operators (DNO) etc., Aggregators, Demand Response service providers, EV charging units etc.

11. Scheduling coordinator for distribution grid.

3.5 Role and Responsibility of State Operation Coordination Committee (SOCC)

1. Objective:

Day by day, the grid operation is becoming more and more challenging as the complexity of the grid is increasing enormously, coupled with a rapidly increasing generation from renewable sources, portfolio of high-capacity generator units, wide variation in demand, planning of outages for generating units and transmission elements, real time incorporation of voluminous revisions from generators and Distribution Licensees.

For secure, smooth, reliable and economical grid operation of the State, formation of a State Operation Coordination Committee is essential for carrying out operation analysis for improving grid performance.

2. Formation:

The Chairperson of the State Operation Coordination Committee shall be Chief Engineer of the SLDC. The State Operation Coordination Committee shall consist of following members:

(a) One representative at senior executive level from each Distribution Licensee, viz., DGVCL, MGVCL,UGVCL, PGVCL, TPL-Ahmedabad and TPL-Surat and any other Distribution Licensee as may be decided by the Commission from time to time.

(b) One representative at senior executive level from each DSO.

(c) One representative at senior executive level from each power station and CorporateOffice of Gujarat State Electricity Corporation Limited (GSECL).

(d) One representative at senior executive level from each IPP.

(e) One representative at senior executive level from STU.

(f) One representative at senior executive level from Transmission Licensees.

(g) One representative at senior executive level from SSP.

(h) One representative at senior executive level from UMPP / MPP connected to Gujaratnetwork with Gujarat as control area.

(i) One representative at senior executive level from SLDC as Member Secretary.

(j) One representative of Renewable Energy generators connected to Intra-State transmission system (wind, solar, wind-solar hybrid, battery storage) having capacity of above 200 MW and on nomination basis.

In addition to the above, the following shall be invitees to the above forum:

(i) One representative at senior executive level from GUVNL

(ii) One representative at senior executive level from NTPC / NPC power stations connected to Gujarat network.

(iii) One representative at senior executive level from UMPP / MPP connected to Gujaratnetwork with control area outside Gujarat.

3. Function:

The Committee will coordinate planning of maintenance of generating units of various generating companies and review the maintenance programme on a quarterly basis. The Committee will discuss and attain consensus on all issues relating to economy and efficiency in the operation of power system in the State. In addition, the Committee will endeavour for a dispute-free and unbiased operation of power system in the State.

3.6 Constitution of PCC

1. The Chairperson of the PCC shall be the headed by Chief Engineer of the SLDC and the Member Secretary of the PCC shall also be a senior executive from the STU.
2. One senior executive from each Intra-State Transmission Licensee shall be member of PCC.
3. One senior executive from each Intra-State State Conventional Generator shall be member of PCC.
4. Two senior executives from Intra-State State RE Generators (having connectivity at 220 kV and above level) shall be member of PCC on rotational basis.

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4 Resource Planning Code

4.1 Integrated Resource Planning:

The integrated resource planning shall include:

i. Demand forecasting as detailed in Regulation 4.2;

ii. Generation resource adequacy planning to meet the projected demand as detailed inRegulation 4.3; and

iii. Transmission resource planning as detailed in Regulation 4.4.

4.2 Demand Forecasting:

1. Each distribution licensee shall estimate the demand in its licence area including the demand of open access consumers and factoring in captive generating plants, energy efficiency measures, distributed generation, demand response, in different time horizons, namely long-term, medium term and short-term. The demand estimation shall be done using trend method, time series, econometric methods or any state-of-the-art methods and shall include daily load curve (hourly basis) for a typical day of each month.

2. Distribution licensees may consider the guideline, if any, developed by Forum of Regulators for demand estimation for achieving consistency and statistical accuracy by taking into consideration the factors such as economic parameters, historical data and sensitivity and probability analysis.

3. STU or such other agency as may be designated by the Commission, based on the demand estimates of the distribution licensees as per Regulation 4.2(i) and in co-ordination with all the distribution licensees, shall estimate the demand for the entire State duly considering the diversity of the State in different time horizons, namely long-term, medium term and short- term.

4.3 Generation Resource Adequacy Planning:

1. After the demand estimation as per Regulation 4.2 of these Regulations, each distribution licensee shall:

i. assess the existing generation resources and identify the additional

generation resource requirement to meet the estimated demand in different time horizons, and

ii. Prepare generation resource procurement plan.

2. Assessment of the existing generation resources shall be done with due regard to their capacity contribution to meet the peak demand of the distribution licensee and the State.

3. Generation resource procurement planning (specifying procurement from resources under State control area and regional control area) shall be undertaken in different time horizons, namely long-term, medium term and short-term to ensure:

   i. adequacy of generation resources and

   ii. Planning Reserve Margin (PRM) taking into account loss of load probability and energy not served as specified by CEA.

4. After considering the demand forecasting and the generation resource procurement planning carried out based on the principles specified under these Regulations, each distribution licensee should ensure demonstrable generation resource adequacy for such period as specified by the Commission. Failure of a distribution licensee to meet the generation resource adequacy target approved by the Commission shall render the concerned distribution licensee liable for payment of resource adequacy non-compliance charge as may be determined by the Commission.

5. For the sake of uniformity in approach and in the interest of optimality in generation resource adequacy in the State, the model Regulation of FOR may be used, containing inter-alia the methodology for generation resource adequacy assessment, generation resource procurement planning and compliance of resource adequacy target by the distribution licensees.

4.4 Transmission resource adequacy assessment

1. STU shall undertake assessment and planning of the intra-State transmission system as per the provisions of the Act and shall inter-alia take into account:

   i. Import and export capability across ISTS and STU interface; and

ii. Adequate power transfer capability across the Intra-State Transmission system.

2. The STU shall be responsible for overall planning of STS and shall prepare a perspective rolling transmission system plan for next 10 years:

Provided that the transmission system plans shall be updated every year to accommodate the revisions in the load projections and generation capacity additions:

Provided further that the STU shall publish on its website the perspective rolling transmission system plan for next 10 years by 30th September for each year:

Provided also that the STU shall publish its ongoing transmission plan on its website.

4.5 Planning Data Requirement:

To enable STU to discharge its responsibilities by conducting system studies and preparation of the perspective plans, all Users shall furnish all the data to STU from time to time and categorised as Planning Data Requirement from the generating and the distribution company, vide **Annexure-1**. The data pertaining to the generating stations including CPPs and generating units owned by Distribution Licensee working in parallel with grid and Distribution Licensees, shall be updated upon any addition of generating unit/ modification of the distribution system.

4.6 System planning:

1. These Regulations formulates the standards and procedures for the system planning to enable STU in consultation with the Users, to evolve an efficient, coordinated, secure and economical intra-State transmission system in order to satisfy the requirements of demand and generation.

2. System Planning specifies the technical and design criteria and procedures to be adopted by STU for the planning and development of the Transmission System. The Users shall take it into account for planning and development of their own system.

3. In accordance with Section 39(2)(b) of the Act, STU shall discharge all functions of planning and coordination relating to intra-State transmission system with SLDC, Central Transmission Utility, State Governments, Generating Companies,

Regional Power Committees, Central Electricity Authority (CEA), Licensees and any other person notified by the State Government in this behalf.

4. Reinforcements and extensions to the system arise due to many reasons of which, a few are mentioned below:

   (a) Development on a user's system already connected to the Transmission System as a user development;

   (b) Introduction of a new Connection Point/ Interface Point between a user's system and the Transmission System;

   (c) Evacuation system for Generating Stations within or outside the State;

   (d) Reactive Compensation;

   (e) Need to increase the system capacity, removal of operational constraints, maintenance of security standards and meeting general increases in demand;

   (f) Steady state and transient stability considerations;

   (g) Cumulative effect of any of the above.

5. The work of such reinforcement and extension to the Transmission System may also involve work at a Connection Point / Interface Point of a generating company/Distribution Licensee to the Transmission System.

6. The development of the Transmission System must be planned, duly allowing sufficient lead-time, considering the following:

   (a) Time required for detailed engineering, design and construction work to be carried out. This system planning therefore, enforces the time scale for exchange of information between the STU and user(s). All the concerned parties, wherever appropriate, shall have due regard to the confidentiality of such information;

   (b) Time required for obtaining all the necessary statutory approvals like notification in government gazette and leading newspapers, Power and Telecommunication Co- ordination Committee (PTCC) clearance, forest clearance, railway clearance, clearance from aviation authorities, national highways, state highways, etc., and the right-of-way permissions wherever required.

4.6.1 Perspective Plan

(a) The load forecasting shall be the primary responsibility of the Distribution Licensee within its area of supply. The Distribution Licensees shall determine the peak load and energy forecasts of their areas for each of the succeeding 10 years and submit the same annually, by 31st January to STU. These shall include the details of demand forecasts, data methodology and assumptions on which the forecasts are based. The peak load and energy forecasts shall be made for the overall area of supply.

(b) The annual peak load forecast shall also be made for each Connection Point / Interface Point with the Transmission System. The peak load requirement at each Connection Point / Interface Point will essentially ensure that the STU may determine the corrective measures to be taken to maintain the capacity adequacy in the Transmission System up to the Connection Point / Interface Point. This will facilitate the Transmission Licensee to develop thecompatible Transmission System. However, if the Distribution Licensee receives power at a number of Connection Points / Interface Points in a compact area, which are interconnected in a ring, then such a Distribution Licensee shall forward the overall long-term demand forecast for the overall Area of Supply as well as at each Connection Point /Interface Point with the variation or tolerance, as mutually discussed and agreed upon with the STU. These forecasts shall be updated annually and also whenever major changes are made in the existing system. Wherever these forecasts take into considerationdemands for power exceeding 5 MW by a single consumer, the Distribution Licensee shall satisfy itself regarding the materialization of such a demand.

(c) The STU shall also review the methodology and assumptions used by the Distribution Licensees in making the load forecasts, in consultation with them. The resulting overall forecast will form the basis of planning for expansion of Transmission System, whichwill be carried out by STU. To maintain the reliability of the interconnected power systems, all participants must comply with the planning criteria / guidelines of CEA as updated from time to time.

(d) STU shall be responsible to prepare and submit a long-term plan to the Commission for the compatible intra-State transmission system expansion to meet the future demand. The planning shall be in conformity with the

national perspective for Power Generation and Transmission plan prepared by the CEA. This compatible intra-State transmission plan shall also include provision for reactive compensation needed for the Transmission System.

(e) The STU shall be responsible for integrating the load forecasts submitted by each of the Distribution Licensees and determining the five-year load forecast on long-term perspective basis load forecasts for the State. For determining the requirements for the entire State, an appropriate diversity factor from the data available for the previous years shall have to be chosen.

(f) The STU shall extend full support to CTU to finalize the annual planning corresponding to a five-year forward term for identification of a major inter-State Transmission System including inter-regional schemes, which shall fit in with the long-term plan developed byCEA.

(g) The STU shall furnish the requisite planning data to CTU, to enable CTU to formulate and finalize the plan, for the next five years.

(h) The system plan shall be formulated keeping in mind the CEA Manual on Transmission Planning Criteria 2023, as well as transmission system planning and security standard as specify in these Regulations.

4.6.2 Planning Philosophy

4.6.3 General guidelines

1. The STU shall carry out the planning process from time to time, as per the requirement for identification of the intra-State transmission system, including the transmission system associated with generation projects and system strengthening schemes, which shall fit in with the perspective plan developed by CEA. While planning schemes, the following shall be considered in addition to the data of authenticated nature collected from and in consultation with Users by STU:

   (i) Perspective plan formulated by CEA

   (ii) Electric Power Survey of India, published by the CEA

   (iii) Transmission Planning criteria and guidelines, issued by the CEA

   (iv) Operational feedback from SLDC

(v) Central Electricity Regulatory Commission (Grant of Connectivity, long-term access and medium-term open access in inter-state transmission and related matters) Regulations, 2009, Gujarat Electricity Regulation Commission (Terms and Conditions of Intra- state Open Access) Regulations, 2011 as amended from time to time

(vi) Renewable Capacity Addition Plan issued by the Ministry of New and Renewable Energy Sources (MNRES), Govt of India, Gujarat Energy Development Association (GEDA), Govt of Gujarat.

2. In addition to the intra-State transmission system, the STU shall plan, from time to time, system-strengthening schemes, the need of which may arise to overcome the constraints in power transfer and to improve the overall performance of the grid. The transmission system is generally augmented to cater to the power transfer requirements posed by eligible entities, for example, for increase in power demand, generation capacity addition including renewable energy (RE) sources, etc. Further, system may also be augmented considering the feedback regarding operational constraints and feedback from drawing entities, transmission licensees and SLDC.

3. The principle for planning of Intra-State system shall be to ensure that it is available as per the requirements of the State Entities and the generators including renewable energy (RE) sources. As far as possible, the transmission system shall be planned and developed matching with growth of generation and load and care shall be taken that there is no wasteful investment.

4. All Users will supply to the STU, the desired planning data (i.e., load growth, generation capacity addition, constraints in existing system, etc.) from time to time to enable to formulate and finalise its plan.

5. The transmission customers as well as utilities shall give their network access requirement well in advance considering time required for implementation of the transmission assets. The transmission customers are also required to provide a reasonable basis for their transmission requirement such as size and completion schedule of their generation facility, demand and their commitment to bear transmission service charges.

6. Planning of transmission system for evacuation of power from hydro projects shall be done river basin-wise considering the identified generation projects and their power potential.

7. In case of highly constrained areas like congested urban / semi-urban area, dense industrial pockets, Special Investment Regions, RE potential pockets, very difficult terrain (including hilly terrain) etc., the transmission corridor may be planned by considering long-term perspective of optimizing the right-of-way and cost. This may be done by adopting higher voltage levels for final system and operating one level below voltage level in the initial stage, or by using multi-circuit towers for stringing circuits in the future, or using new technology.

8. Routing of the transmission line may be planned in accordance with Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022 and its amendments or re-enactment thereof, to minimise Right of Way (Row), technical options and line configurations.

9. The PM Gati Shakti National Master Plan (PMGS-NMP) was launched on 13th October 2021 for providing multimodal connectivity infrastructure to various economic zones. It provides a digital platform for integrated planning and coordinated implementation of infrastructure connectivity projects. The information available on this platform is to be used while planning of transmission system. For planning of any new transmission lines or substations, the portal of PMGS-NMP is to be used to identify preliminary feasibility of the same.

10. In line with Section 39 of the Act, STU shall act as the nodal agency for InSTS planning in coordination with distribution licensees and intra-State generators connected / to be connected in the STU grid. The STU shall be the single point contact for the purpose of Intra-State Transmission planning and shall be responsible on behalf of all the intra-State entities, for evacuation of power from the State generating stations, meeting requirements of DISCOMs, and exchange of power with ISTS commensurate with the ISTS plan with due consideration to the margins available in existing system.

11. Normally, the various intra-State entities shall be supplied power through the intra-State network. Only under exceptional circumstances, the load serving intra-State entity may be allowed direct inter-connection with ISTS on recommendation of STU provided that such an entity would continue as intra-State entity for the purpose of all jurisdictional matters including energy accounting. Under such situation, this direct interconnection may also be used

by other intra-State entity(ies). Further, STU shall coordinate with urban planning agencies, Special Economic Zone (SEZ) developers, industrial developers, etc., to keep adequate provision for transmission corridor and land for new substations for their power transfer requirements.

12. The system parameters and loading of system elements shall remain within permissible limits. The adequacy of the transmission system should be tested for different probable load-generation scenarios as detailed in Chapter-3 of Manual on Transmission Planning Criteria issued by the CEA.

13. As voltage management plays an important role in transmission of energy, special attention shall be accorded by STU for planning of capacitors, reactors, SVC and Flexible Alternating Current Transmission Systems (FACTS), etc., to optimise the utilization of the integrated transmission network.

14. Based on plans prepared by the CTU, STU shall have to plan its system to further evacuate power from the ISTS and to optimise the use of the integrated transmission network.

15. The system shall be planned to operate within permissible limits both under normal as well as after probable credible contingency(ies) as detailed in the CEA manual on transmission Planning criteria, 2023. However, the system may experience extreme contingencies which are rare, and the system may not be planned for such rare contingencies. To ensure security of the grid, the extreme/rare but credible contingencies should be identified from time to time and suitable defence mechanism, such as - load shedding, generation rescheduling, islanding, system protection schemes, Automatic Under Frequency Load Shedding (AUFLS) schemes (AUF Relay and df/dt), etc. may be worked out to mitigate their adverse impact.

16. For strengthening of the transmission network, cost, reliability, right-of way requirements, transmission losses, down time (in case of up-gradation and re-conductoring options), etc., need to be studied. If need arises, addition of new transmission lines/ substations to avoid overloading of existing system including adoption of next higher voltage may be explored.

17. Critical loads such as - railways, metro rail, airports, refineries, underground mines, steel plants, smelter plants, etc., shall plan their interconnection with the grid, with 100% redundancy and as far as possible from two different sources of supply.

18. Communication system for new transmission system shall be planned and implemented in accordance with Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022 and its amendments or re-enactment thereof, Central Electricity Authority (Technical Standards for Communication System in Power System Operations) Regulations, 2020 and its amendments or re-enactment thereof and CEA Manual of Communication Planning in Power System Operation 2022 and its amendments, such that the communication system is available at the time of commissioning of the transmission system.

4.6.3.1 TRANSMISSION PLANNING

a) Power system data for transmission planning modelling

1. For InSTS planning, the transmission network may be modelled down to 66 kV level and lumping of generating units and loads may be considered accordingly. The STU may consider modelling of smaller generating units if required.

2. For modelling of various elements, actual system data wherever available shall be used. In case where data is not available, standard data given in CEA Manual on Transmission Planning Criteria, 2023 may be used.

b) Time Horizons for transmission planning

Concept to commissioning of transmission elements generally takes about three to five years; about two to three years for augmentation of capacitors, reactors, transformers, etc., and about four to five years for new transmission lines or substations. Therefore, system studies for firming up the transmission plans may be carried out with 3-5 year time horizon on rolling basis every year.

c) Load - generation scenarios

The load-generation scenarios shall be worked out in a pragmatic manner so as to reflect the typical daily and seasonal variations in load demand and generation availability. Typical load generation scenario may include high/low Wind, high / nil Solar, high/low Hydro generation, high demand, low demand and combinations thereof.

d) Loads

1. Active power (MW)

The system peak demand shall be based on the latest Electric Power Survey (EPS) report of CEA. However, the same may be moderated based on actual load growth of past five (5) years.

i. The load demands at other periods (seasonal variations and minimum loads) shall be derived based on the annual peak demand and past pattern of load variations.

ii. While doing the simulation, if the peak load figures are more than the peaking availability of generation, the loads may be suitably adjusted substation-wise to match with the availability. Similarly, if the peaking availability is more than the peak load, the generation dispatches may be suitably reduced to the extent possible, considering merit order dispatch.

(I) From practical considerations, the load variations over the year shall be considered as under:

- Annual Peak Load
- Seasonal variation in Peak Loads for Winter, Summer and Monsoon
- Seasonal Light Load
- Variation of peak load in region and time of day.

(II) Actual demand data, wherever available, should be used. In cases where data is not available, the load may be calculated using load factors given in CEA Manual on Transmission Planning Criteria, 2023.

2. Reactive power (MVAr)

i. Reactive power plays an important role in EHV transmission system planning and hence, forecast of reactive power demand on an area-wise or substation-wise basis is as important as active power forecast. This forecast would require adequate data on the reactive power demands at the different substations as well as the projected plans (including existing, if any) for reactive power compensation.

ii. For developing an optimal Intra-State Transmission System, the Users must clearly spell out the substation-wise maximum and minimum demand in MW and MVAr on seasonal basis. In the absence of MVAr data, the load power factor shall be taken as per Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 and its amendments or re-enactment thereof. Adequate reactive compensation shall be provided to bring power factor as close to unity at 132 kV and 220 kV voltage levels.

iii. Reactive power capability of generators including RE generators shall be as per provisions of Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 and its amendments or re-enactment thereof

e) Generation dispatches and modelling

i. For the purpose of development of Load Generation scenarios on State as a whole basis, the State peaking availability may be calculated as per seasonal and daily variations based on the past pattern of generation variations.

ii. For evolving transmission systems for integration of RE generation projects, high wind/solar generation injections may also be studied in combination with suitable conventional dispatch scenarios. In such scenarios, the generation of Intra-State generating station may be adjusted as per technical minimum limits. The maximum generation at a wind/solar aggregation level may be calculated using capacity factors as per the norms given CEA Manual on Transmission Planning Criteria, 2023.

f) Special area dispatches such as following may be considered in planning, wherever necessary:

i. Special dispatches corresponding to high agricultural load/lift irrigation pump schemes with low power factor, wherever applicable.

ii. Complete closure of a generating station close to a major load centre.

g) In case of coal based thermal power generating units, the minimum level of output (ex-bus generation, i.e., net of the auxiliary consumption) shall be taken as not less than 40% of the rated installed capacity.

h) The generating units shall be modelled to run as per their respective capability curves. In the absence of capability curve, the reactive power limits (Q_{max} and Q_{min}) and Maximum Active Power (P_{max}) for generating units can be taken as under:

Type of generating unit	**Q_{max}**	**Q_{min}**
Thermal units	Q_{max} = 0.60 x P_{max}	Q_{min} = (-)0.30 x P_{max}
Nuclear units	Q_{max} = 0.50 x P_{max}	Q_{min} = 0
Hydro units	Q_{max} = 0.48 x P_{max}	Q_{min} = (-)0.24 x P_{max}
Wind / Solar / BESS	Q_{max} = 0.33 x P_{max}	Q_{min} = (-)0.33 x P_{max}

i) It shall be duty of all the generators to provide technical details of generating units, such as generator (including machine capability curves), exciter, governor, PSS parameters, etc., for modelling of their machines for steady-state and transient-state studies. In case of Wind/Solar/BESS, equivalent generator model shall also be provided.

j) Planning margins

i. In a very large interconnected grid, there can be unpredictable power flows in real time due to variation in load-generation balance with respect to anticipated load generation balance in different pockets of the grid. This may lead to overloading of transmission elements during operation, which cannot be predicted in advance at the planning stage. This can also happen due to delay in commissioning of a few planned transmission elements, delay/abandoning of planned generation additions or load growth at variance with the estimates. Such uncertainties are unavoidable and hence, some margins at the planning stage may help in reducing impact of such uncertainties. However, care also need to be taken to avoid stranded transmission assets. Therefore, at the planning stage, planning margins need to be provided.

ii. Against the requirement of power transfer, the new transmission lines emanating from a power station to the nearest grid point may be planned

considering overload capacity of the generating stations in consultation with generators.

iii. At the planning stage, a margin of about ± 2% may be kept in the voltage limits and thus, the voltages under load flow studies (for 'N-0' and 'N-1' steady-state conditions only) may be maintained within the limits given below:

Voltage (kV_{rms}) (after planning margins)		
Nominal	**Maximum**	**Minimum**
765	785 (1.03 pu)	745 (0.97 pu)
400	412 (1.03 pu)	388 (0.97 pu)
230	240 (1.04 pu)	212 (0.92 pu)
220	240 (1.09 pu)	203 (0.92 pu)
132	142 (1.08 pu)	125 (0.95 pu)
110	119 (1.08 pu)	102 (0.93 pu)
66	70 (1.06 pu)	62 (0.94 pu)

iv. In planning studies, all the transformers may be kept at nominal taps and On Load Tap Changer (OLTC) may not be considered. The effect of the taps should be kept as operational margin.

v. For the purpose of load flow studies at planning stage, the nuclear generating units shall normally not run at leading power factor. To keep some margin at planning stage, the reactive power limits (Q_{max} and Q_{min}) for generating units may be taken as under:

Type of generating unit	**Q_{max}**	**Q_{min}**
Thermal Units	Q_{max} = 0.50 x P_{max}	Q_{min} = (-)0.10 x P_{max}
Nuclear units	Q_{max} = 0.40 x P_{max}	Q_{min} = 0
Hydro units	Q_{max} = 0.40 x P_{max}	Q_{min} = (-)0.20 x P_{max}
Wind / Solar / BESS	Q_{max} = 0.20 x P_{max}	Q_{min} = (-)0.20 x P_{max}

Note: In case of limitation in Q_{max} and Q_{min}, similar ratio of margins as provided in Regulation 4.6.2.2(h) and Regulation 4.6.2.2(j), shall be considered for the generating unit with respect to capability curve.

vi. Notwithstanding above, during operation, as per the instructions of the System Operator, the generating units shall operate at leading power factor within their respective capability curves.

k) System studies for transmission planning

1. The system shall be planned based on one or more of the following power system studies, as per requirements:

   i) Power Flow Studies

   ii) Short Circuit Studies

   iii) Stability Studies

   iv) TTC/ATC Calculations

2. Additional studies as given below may be carried out at appropriate time as per requirement.

   i) EMT studies

   ii) Inertia studies

Details of the studies are discussed in subsequent paragraphs.

l) Power Flow studies

i. Load flow study is the steady state analysis of power system network. It determines the operating state of the system for a given load generation balance in the system. It helps in determination of loading on transmission elements and helps in planning and operation of power systems from steady state point of view.

ii. All the elements of transmission network, viz., transmission lines, transformers, generators, load, bus reactors, line reactors, HVDC, FACTS, etc., are modelled using steady state parameters in the simulation software.

iii. Load flow solves a set of simultaneous non-linear algebraic power equations for the two unknown variables ($|V|$ and $\angle\delta$) at each node in a system. The output of the load flow analysis is the voltage and phase angle, real and reactive power, losses and slack bus power.

iv. The parameters calculated at sub-Clause III above should be within the planning margins specified in Regulation 4.6.2.2(j).

m) Short circuit studies

i. The short circuit studies shall be carried out using the classical method with flat pre-fault voltages and sub-transient reactance (X''_d) of the synchronous machines.

ii. For inverter-based generators, the response of an inverter to grid disturbances is a function of the controls programmed into the inverter and the rated capability of the inverter. Wind / Solar / Hybrid plants need to clearly articulate how the inverter would behave during fault events to ensure that the correct response is provided during and immediately following fault conditions. In case of non-availability of data, sub-transient reactance (X''_d) for wind and solar generation may be assumed as 0.85 pu and 1 pu respectively for short circuit studies.

iii. MVA of all the generating units in a plant may be considered for determining maximum short-circuit level at various buses in system. This short-circuit level may be considered for substation planning.

iv. Vector group of the transformers shall be considered for doing short circuit studies for asymmetrical faults. Inter-winding reactances in case of three winding transformers shall also be considered. For evaluating the short circuit levels at a generating bus (11 kV, 13.8 kV, 21 kV, etc.), the unit and its generator transformer shall be represented separately.

v. Short circuit level for both, three phase to ground fault, and single phase to ground fault shall be calculated.

vi. The short-circuit level in the system varies with operating conditions, it may be low for light load scenario as compared to peak load scenario, as some of the plants / unit(s) may not be on-bar. For getting an understanding of system strength under different load-generation / export-import scenarios, the MVA of only those machines shall be taken which are on bar in that scenario.

n) Stability Studies

i. Power System Stability may be broadly defined as property of a power system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after being subjected to a disturbance. Stability is a condition of equilibrium between opposing forces.

ii. Rotor Angle Stability is the ability of interconnected synchronous machines of a power system to remain in synchronism. The stability problem involves the study of the electromechanical oscillations inherent in power system.

iii. In transient stability studies, the contingencies usually considered are short-circuits of different types: phase-to-ground, phase-to-phase-to-ground, or three phases to ground. They are usually assumed to occur on transmission lines, but occasionally bus or transformer faults are also considered. The fault is assumed to be cleared by the opening of appropriate circuit breakers to isolate the faulted element. In some cases, high-speed re-closure may be assumed.

iv. In transient stability studies, the study period of interest is usually limited to 3 to seconds following the disturbance, although it may extend to about 10 seconds for very large systems with dominant inter-area modes of oscillation.

v. During the analysis, impact due to tripping of one line of a radially connected generator may be studied.

vi. Voltage stability is the ability of a power system to maintain steady acceptable voltages at all buses in the system under normal operating conditions and after being subjected to a disturbance. The system enters a state of voltage instability when there is disturbance/ increase in load demand / change in system condition which causes a progressive and uncontrollable drop in voltage. The main factor causing instability is the inability of the power system to meet the demand for reactive power. The heart of the problem is usually the voltage drop that occurs when active power and reactive power flow through inductive reactances associated with the transmission network.

vii. A criterion for voltage stability is that, at a given operating condition for every bus in the system, the bus voltage magnitude increases as the reactive power

injection at the same bus is increased. A system is voltage unstable if, for at least one bus in the system, the bus voltage magnitude (V) decreases as the reactive power injection (Q) at the same bus is increased. In other words, a system is voltage stable if V-Q sensitivity is positive for every bus and voltage unstable if V-Q sensitivity is negative for at least one bus.

viii. The candidate transmission elements for which stability studies may be carried out, may be selected through results of load flow studies. Choice of candidate transmission elements for stability studies are left to transmission planner.

ix. Generally, the lines for which the angular difference between its terminal buses is more than 20 degrees after contingency of one circuit may be selected for performing stability studies.

x. Voltage Stability Studies: These studies may be carried out using load flow analysis program by creating a fictitious synchronous condenser at critical buses which are likely to have wide variation in voltage under various operating conditions i.e. bus is converted into a PV bus without reactive power limits. By reducing desired voltage of this bus, MVAr generation/ absorption is monitored. When voltage is reduced to some level it may be observed that MVAr absorption does not increase by reducing voltage further instead it also gets reduced. The voltage where MVAr absorption does not increase any further is known as Knee Point of Q-V curve. The knee point of Q-V curve represents the point of voltage instability. The horizontal 'distance' of the knee point to the zero-MVAr vertical axis measured in MVAr is therefore an indicator of the proximity to the voltage collapse.

xi. Each bus shall operate above Knee Point of Q-V curve under all normal as well as the contingency conditions detailed in Chapter-4. The system shall have adequate margins in terms of voltage stability.

o) TTC/ATC Calculation

i. The studies to assess TTC, ATC and TRM of InSTS corridors for the future timeframe are to be carried out considering the load generation balance and planned transmission system.

ii. While carrying out the studies, limiting condition on some portions of the transmission corridors may shift as the network operating conditions change

over time. TTC would be the minimum of the transmission capability arrived at taking into consideration the Thermal, Voltage and Stability loading limits. TRM of the inter-regional corridor would be arrived at by considering the worst credible contingency.

iii. The TTC, ATC and TRM values of transmission corridors may be revised due to change in system conditions, which includes change in network topology/change in anticipated Load-Generation balance for the future study timeframe.

p) EMT studies

i. Electro Magnetic Transient (EMT) study simulate electromagnetic, electromechanical and control system transient on multiphase electric power system.

ii. EMT represents the power system and its control system by their differential equations. The solution of these equations is obtained in time domain. The response of the power system to any disturbance can be obtained at any frequency. Typically Temporary Over Voltage, Switching Over Voltage, Ferro resonance, Sub-Synchronous Resonance, Insulation Coordination, etc., are performed under EMT studies.

iii. During EMT studies, transmission elements, viz., transmission line, transformer/reactor, Generator, Circuit Breaker, Lightning Arrester, FACTS, etc., are modelled in detail. The equivalent grid is modelled as a constant voltage source behind an impedance. The switching sequence of the model under study is carried out as per requirement of TOV the study analysis.

iv. Temporary Over Voltage (TOV): TOVs are undamped or little damped power-frequency over-voltages of relatively long duration (i.e., seconds, even minutes). They are often preceded by a transient overvoltage resulting from a switching operation, sudden load rejection, single line to ground fault, etc., in a no / lightly loaded system. EMT studies provides to characterize TOV, determine resulting problems, and evaluate mitigation alternatives.

v. Switching Over Voltage: When a circuit breaker of an overhead transmission line is closed and line is energised, some switching transients are generated in the power system. Lightning and switching are two primary causes of transient overvoltage in power systems. Switching transients are an important factor in

the equipment selection, protection and conductor clearances. Transmission Line Models with frequency dependent parameters are usually used for accurate modelling of EHV lines during switching overvoltage evaluation.

vi. Sub-Synchronous Resonance (SSR): Generally, the series compensated transmission lines may cause SSR in the turbine generators, such that it leads to the electrical instability at sub synchronous frequencies resulting in turbine-generator shaft failures.

vii. Insulation Coordination: Insulation Coordination is a method /procedure to select the dielectric strength of equipment vis-à-vis operating voltages and transient over-voltages which may appear on the system for which the equipment is designed / intended to operate.

viii. Ferro resonance

a. Ferro resonance is a general term applied to a wide variety of interactions between capacitors and iron-core inductors that result in unusual voltages and/or currents. In linear circuits, resonance occurs when the capacitive reactance equals the inductive reactance at the frequency at which the circuit is driven. Iron-core inductors have a non-linear characteristic and have a range of inductance values. Therefore, there may not be a case where the inductive reactance is equal to the capacitive reactance, but yet very high and damaging overvoltage occurs.

b. In power system, Ferro resonance occurs when a nonlinear inductor is fed from a series capacitor. The nonlinear inductor in power system can be due to: a) The magnetic core of a wound type voltage transformer, b) Bank type transformer, c) The complex structure of a 3 limb three-phase power transformer (core type transformer), d) The complex structure of a 5 limb three-phase power transformer (shell-type transformer).

c. Power transformers, under no-load or light-load conditions, are prone to be driven into Ferro resonance when energized through a long overhead lines or series compensated (FSC/TCSC) lines or underground cable (capacitive connection). Power transformer connected to a de-energized transmission line running in parallel with energized line can also drive the power transformer into Ferro resonance.

d. From the HVDC point of view, Ferro resonance should be eliminated to

avoid unnecessary protective actions due to high levels of harmonic distortion.

e. Therefore, system study for Ferro-resonance may be carried out for the selective location such as line with series capacitance and lightly loaded transformers etc.

q) Inertia

i. Inertia is the property, which resists change in its existing state. In power system, it refers to the energy stored in large rotating generators, which gives them the tendency to remain rotating. Inertia plays an important role in arresting the frequency drop during contingencies. In the grid, it gives the system operator a chance to respond to power plant failures giving other systems time to respond and rebalance supply and demand.

ii. With the high penetration of renewable energy sources like wind and solar power and gradual reduction/decommissioning of conventional generators, total system inertia of grid would decline. However, Battery Energy Storage Systems (BESS), Synchronous Condenser, etc., can provide fast response to arrest the frequency decline and help restore the frequency.

iii. Determination of system inertia is essential for frequency stability assessment. Studies for assessing the system inertia would require modelling of individual generators including Wind / Solar plants. Data for the same has to be provided by generating companies.

iv. The rate of change of frequency (RoCoF) in Hertz per second (or Hz/s) shall be calculated based on simulation studies for the lowest inertia period (usually the highest RE penetration period or lowest demand period).

Following contingencies may be considered for the RoCoF calculation purpose:

- Generation Contingency: The largest generating station including RE in the system or the station whose loss produces the highest RoCoF.
- Load Contingency: The largest load in the system (generally an industrial load).
- Determine whether the calculated RoCoF is lower than the maximum

permissible RoCoF value.

- The maximum permissible RoCoF shall be such that the 1st stage UFLS does not get triggered and frequency remains 0.1 Hz above 1st stage of UFLS.

4.6.3.2 CRITERIA FOR CONTINGENCY

1. General Principles

The transmission system shall be planned considering following general principles:

a) In normal operation ('N-0') of the grid, with all elements to be available in service in the time horizon of study, it is required that all the system parameters like voltages, loadings, frequency should remain within permissible normal limits.

b) The grid may however be subjected to outage / loss of an element and it is required that after loss of an element ('N-1' or single contingency), all the system parameters like voltages, loadings, frequency, shall be within permissible normal limits.

c) Under outage / loss of an element, the grid may experience another contingency, though less probable ('N-1-1'), wherein some of the equipment may be loaded up to their emergency limits. To bring the system parameters back within their normal limits, load shedding/re-scheduling of generation may have to be done, either manually or through automatic system protection schemes (SPS). Such measures shall generally be applied within one hour after the disturbance.

2. Permissible normal and emergency limits

a) Normal thermal ratings and normal voltage limits represent equipment limits that can be sustained on continuous basis. Emergency thermal ratings and emergency voltage limits represent equipment limits that can be tolerated for a relatively short time, which may be one hour to two hours, depending on design of the equipment. The normal and emergency ratings to be used in this context are given in subsequent paragraphs.

b) The loading limit for a transmission line shall be its thermal loading limit. The

thermal loading limit of a line is determined by design parameters based on ambient temperature, maximum permissible conductor temperature, wind speed, solar radiation, absorption coefficient, emissivity coefficient, etc. During planning, the ambient temperature and other factors are assumed to be fixed, thereby permitting margins during operation. Generally, the ambient temperature may be taken as 45 deg Celsius; however, in some areas like hilly areas where ambient temperatures are less, the same may be taken. The maximum permissible thermal line loadings for different types of line configurations, employing various types of conductors, are given in CEA Manual on Transmission Planning Criteria, 2023.

c) Design of transmission lines with various types of conductors should be based on conductor temperature limit, right-of-way optimization, losses in the line, cost and reliability considerations, etc.

d) The loading limit for an inter-connecting transformer (ICT) shall be its name plate rating.

e) During planning, a margin as specified in Regulation 4.6.2.2(j) shall be kept in the above lines/transformers loading limits.

f) The emergency thermal limits for the purpose of planning shall be 120% of the normal thermal limits for one hour and 110% of the normal thermal limits for two hours.

g) In real time system operation, capacity of transmission line may be assessed through Dynamic Line Loading, however, this may not be used while transmission system planning.

3. Voltage limits

a) The steady-state voltage limits are given below. However, at the planning stage a margin as specified at Regulation 4.6.2.2(j) may be kept in the voltage limits.

Voltages (kV_{rms})				
	Normal rating		**Emergency rating**	
Nominal	**Maximum**	**Minimum**	**Maximum**	**Minimum**
765 (1 pu)	800 (1.05 pu)	728 (0.95 pu)	800 (1.05 pu)	713 (0.93 pu)
400 (1 pu)	420 (1.05 pu)	380 (0.95 pu)	420 (1.05 pu)	372 (0.93 pu)
230 (1 pu)	245 (1.07 pu)	207 (0.90 pu)	245 (1.07 pu)	202 (0.88 pu)

Voltages (kV_{rms})				
	Normal rating		Emergency rating	
Nominal	**Maximum**	**Minimum**	**Maximum**	**Minimum**
220 (1 pu)	245 (1.11 pu)	198 (0.90 pu)	245 (1.11 pu)	194 (0.88 pu)
132 (1 pu)	145 (1.10 pu)	122 (0.92 pu)	145 (1.10 pu)	119 (0.90 pu)
110 (1 pu)	123 (1.12 pu)	99 (0.90 pu)	123 (1.12 pu)	97 (0.88 pu)
66 (1 pu)	72.5 (1.10 pu)	60 (0.91 pu)	72.5 (1.10 pu)	59 (0.89 pu)

b) Temporary over voltage limits due to sudden load rejection:

i) 800 kV system 1.4 p.u. peak phase to neutral (653 kV = 1 p.u.)

ii) 420 kV system 1.5 p.u. peak phase to neutral (343 kV = 1 p.u.)

iii) 245 kV system 1.8 p.u. peak phase to neutral (200 kV = 1 p.u.)

iv) 145 kV system 1.8 p.u. peak phase to neutral (118 kV = 1 p.u.)

v) 123 kV system 1.8 p.u. peak phase to neutral (100 kV = 1 p.u.)

vi) 72.5 kV system 1.9 p.u. peak phase to neutral (59 kV = 1 p.u.)

c) Switching over voltage limits:

i) 800 kV system 1.9 p.u. peak phase to neutral (653 kV = 1 p.u.)

ii) 420 kV system 2.5 p.u. peak phase to neutral (343 kV = 1 p.u.)

4. Reliability criteria

a) No contingency ('N-0')

i. The system shall be tested for all the load-generation scenarios as given in this document at Regulation 4.6.2.2(c).

ii. For the planning purpose all the equipment shall remain within their normal thermal loadings and voltage ratings.

iii. The angular separation between adjacent buses shall not exceed 30 degrees.

b) Single contingency ('N-1')

i. Steady-state:

All the equipment in the transmission system shall remain within their normal thermal and voltage ratings after outage / loss of any one of the following elements (called single contingency or 'N-1'), but without load shedding / rescheduling of generation:

- Outage of a 132 kV single circuit,
- Outage of a 220 kV single circuit,
- Outage of a 400 kV single circuit (with or without fixed series capacitor),
- Outage of an Inter-Connecting Transformer (ICT) / power transformer,
- Outage of a 765 kV single circuit
- Outage of one pole of HVDC bipole

The angular separation between adjacent buses under 'N-1' shall not exceed 30 degrees.

'N-1' criteria for FACTS devices may not be considered, however, studies may be carried out to address the issues like reduction in transfer capability, restriction on generation evacuation, etc. in case of outage of FACTS devices.

ii. Transient-state:

Usually, perturbation causes a transient that is oscillatory in nature, but if the system is stable, the oscillations will be damped. The system is said to be stable in which synchronous machines, when perturbed, will either return to their original state, if there is no change in exchange of power or will acquire new state asymptotically without losing synchronism. The transmission system shall be stable after it is subjected to one of the following outage / losses:

- The system shall be able to survive a permanent three phase to ground fault on a 765 kV line close to the bus to be cleared in 100 ms.
- The system shall be able to survive a permanent single phase to ground fault on a 765 kV line close to the bus. Accordingly, single pole opening (100 ms)

of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

- The system shall be able to survive a permanent three phase to ground fault on a 400 kV line close to the bus to be cleared in 100 ms.

- The system shall be able to survive a permanent single phase to ground fault on a 400 kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

- In case of 220 kV / 132 kV networks, the system shall be able to survive a permanent three phase fault on one circuit, close to a bus, with a fault clearing time of 160 ms (8 cycles) assuming 3-pole opening.

- The system shall be able to survive a fault in HVDC convertor station, resulting in permanent outage of one of the poles of HVDC Bipole.

- Loss of generation: The system shall remain stable under the loss of single largest generating unit or a critical generating unit (choice of candidate critical generating unit is left to the transmission planner).

- Loss of largest radial load, connected at single point.

c) Second contingency ('N-1-1')

Under the scenario as defined at Paragraph (b) above the system may experience another contingency (called 'N-1-1'):

i. The system shall be able to survive a temporary single phase to ground fault on a 765 kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and successful re-closure (dead time 1 second) shall be considered.

ii. The system shall be able to survive a permanent single phase to ground fault on a 400 kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

iii. In case of 220 kV / 132 kV networks, the system shall be able to survive a permanent three phase fault on one circuit, close to a bus, with a fault

clearing time of 160 ms (8 cycles) assuming 3-pole opening.

iv. In the 'N-1-1' as stated above, if there is a temporary fault, the system shall not lose the second element after clearing of fault but shall successfully survive the disturbance.

v. In case of permanent fault, the system shall lose the second element as a result of fault clearing and thereafter, shall asymptotically reach to a new steady state without losing synchronism. In this new state, the system parameters (i.e. voltages and line loadings) shall not exceed emergency limits, however, there may be requirement of load shedding / rescheduling of generation so as to bring system parameters within normal limits.

d) Radially connected generation with the grid

For the transmission system connecting generator(s) radially with the grid, the following criteria shall apply:

i. The radial system shall meet 'N-1' reliability criteria as given at Regulation 4.6.2.3(4)(b) for both the steady-state as well as transient-state.

ii. For subsequent contingency, i.e., 'N-1-1' (as given at Regulation 4.6.2.3(4)(c), only temporary fault shall be considered for the radial system.

iii. If the 'N-1-1' contingency is of permanent nature or any disturbance/contingency causes disconnection of such generator(s) from the main grid, the remaining main grid shall asymptotically reach to a new steady-state without losing synchronism after loss of generation. In this new state, the system parameters shall not exceed emergency limits, however, there may be requirement of load shedding / rescheduling of generation so as to bring system parameters within normal limits.

iv. The 'N-1' criteria may not be applied to the immediate connectivity system of renewable generations with the ISTS/Intra-STS grid, i.e., the line connecting the generation project switchyard to the grid and the step-up transformers at the grid station:

Provided that 'N-1' criteria shall be applicable in case of renewable generation projects with storage, which are firm in nature and fully dispatchable:

Provided further that 'N-1' reliability criteria may be considered for ICTs at the

ISTS / STU pooling stations for renewable energy based generation of more than 1000 MW after considering the capacity factor of renewable generating stations.

5. SUBSTATION CRITERIA

a) General criteria

i. There may be need for upgradation of the system or renovation and modernization of the existing system depending on technological options and system studies. Therefore, transmission licensee shall provide details to CEA/CTU/STU of the transmission equipment, which are required to be upgraded or for which renovation and modernization needs to be carried out.

ii. As far as possible, an incoming and an outgoing feeder of same voltage level in a substation may be terminated in bays of same diameter in one and half breaker switching scheme, so as to make direct connection in case of outage of the substation, especially in case of Loop-in Loop-out of existing line(s).

iii. Line approaching substation shall normally be perpendicular to the substation boundary for a stretch of 2-3 km.

iv. The maximum short-circuit level on any new substation bus should not exceed 80% of the rated short circuit capacity of the substation equipment. The 20% margin is intended to take care of the increase in short-circuit levels as the system grows. The rated breaking current capability of switchgear at different voltage levels may be taken as given below:

Voltage Level	Rated Breaking Capacity
765 kV	50 kA / 63 kA
400 kV	63 kA / 80 kA
220 kV	40 kA / 50 kA / 63 kA
132 kV	25 kA / 31.5 kA / 40 kA
66kV	31.5 kA

Measures such as sectionalisation of bus, series reactor, or any new technology may also be adopted to limit the short circuit levels at existing substations wherever short circuit levels are likely to cross the designed limits.

v. Rating of the various substation equipment shall be such that they do not limit the loading limits of connected transmission lines.

vi. Connection arrangement of switchable line reactors shall be such that it can be used as line reactor as well as bus reactor with suitable NGR bypass arrangement.

b) Transformers

i. Sub-stations may be classified into two categories i.e. (i) Load Serving Sub-station (LSS) where loads are connected (ii) Generation Pooling Sub-station (GPS) where generating stations are connected directly or through dedicated transmission line for evacuation of their power:

Provided that the substations where both generator(s) and load(s) are connected, shall be treated as load serving sub-station.

ii. The capacity of any single sub-station at different voltage levels shall not normally exceed as given in column (B) and (C) in the following table:

Voltage Level (A)	**Transformation Capacity**	
	Load Serving Substation (B)	**Generation Pooling substations (C)**
765 kV	9000 MVA	9000 MVA
400 kV	2500 MVA	5000 MVA
220 kV	1000 MVA	1000 MVA
132 kV	500 MVA	500 MVA
66 kV	160 MVA	160 MVA

iii. Size and number of interconnecting transformers (ICTs) shall be planned in such a way that the outage of any single unit would not overload the remaining ICT(s) or the underlying system.

iv. While augmenting the transformation capacity at an existing substation or planning a new substation, the fault level of the substation shall also be kept in view. If the fault level is low, the voltage stability studies shall be carried out.

v. In all substations (132 kV and above), at least two transformers shall be provided.

c) Bus- Sectionalisation

i. To have minimum disruption during struck breaker condition, the bus switching scheme provided in Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022 and its amendments or re-enactment thereof shall be implemented.

ii. Sources and loads should be mixed in each diameter to maximize reliability in 'one and half breaker scheme' during planning of a new substation. Hence, one double circuit line consisting of two numbers feeders and originating from a transmission or generating switchyard shall not be terminated in one diameter. Similarly, termination of two numbers of transformers of identical primary voltage rating in one diameter of 'one and half breaker scheme' shall be avoided so that sudden outage is minimized. Layout and bus switching scheme of a substation shall be planned in such way that it shall have maintainability, operation flexibility, security and reliability.

iii. Bus switching scheme shall be as per Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022 and its amendments or re-enactment thereof. Bus section shall be planned in such a way that feeders are adequately distributed with respect to power flow with bus sectionalisers open condition. Further, sectionaliser arrangement may be implemented also keeping in view transformation capacity in each section, fault current rating adopted, number of feeders etc.

6. Reactive Power compensation

a) General

i. Requirement of reactive power compensation through shunt capacitors, shunt reactors (bus reactors or line reactors), static VAr compensators, fixed series capacitor, variable series capacitor (thyristor controlled) or other FACTS devices shall be assessed through appropriate studies.

ii. STU shall carry out planning studies for Reactive Power compensation including reactive power compensation requirement at the existing generator's/ bulk consumers' switchyard and for connectivity of new generator's / bulk consumers to the intra-State transmission system. Reactive compensation shall be provided as far as possible in the low voltage systems with a view to meet the reactive power requirements of load close to the load points, thereby avoiding the need for VAr transfer from high voltage system to the low voltage system. In the cases where network below 132 kV/220 kV voltage level is not represented in the system planning studies, the shunt capacitors required for meeting the reactive power requirements of loads shall be provided at the 132 kV/220 kV buses for simulation purpose.

iii. Near to large RE complex(es) synchronous condenser(s) may be planned for

dynamic voltage support, in addition to FACTS devices.

iv. While planning of bus capacitors/reactors, aspects such as voltage sensitivity due to switching of these devices, size, reliability (contingency), etc., shall be considered.

v. Space provision for converting fixed line reactors/switchable line reactors to be usable as bus reactors after line opening with bypass arrangement for NGR/control switching.

vi. RE generators to have provision to operate the generators in voltage control mode, fixed-Q and power factor control mode as per the grid requirements.

vii. While planning Bus Reactor (BR), size, reliability aspect (outage of BR), etc., may be taken care of.

b) Shunt capacitors

i. Reactive Compensation shall be provided as far as possible in the low voltage systems with a view to meet the reactive power requirements of load close to the load points, thereby avoiding the need for VAr transfer from high voltage system to the low voltage system. In the cases where network below 132 kV/220 kV voltage level is not represented in the system planning studies, the shunt capacitors required for meeting the reactive power requirements of loads shall be provided at the 132 kV/220 kV buses for simulation purpose.

ii. It shall be the responsibility of the respective utility to bring the load power factor as close to unity as possible by providing shunt capacitors at appropriate places in their system.

iii. Reactive power flow through 400/220 kV or 400/132 kV or 220/132(or 66) kV or 220/33kV ICTs, shall be minimal. Wherever voltage on HV side of such an ICT is less than 0.975 pu, no reactive power shall flow down through the ICT. Similarly, wherever voltage on HV side of the ICT is more than 1.025 pu, no reactive power shall flow up through the ICT. These criteria shall apply under the N-0 conditions. It shall be responsibility of respective STU to plan suitable reactive compensation in their network including at 220 kV and 132 kV levels connected to ISTS, in order to fulfil this provision.

c) Shunt reactors

i. Bus reactors shall be provided at EHV substations for controlling voltages within the limits [defined in the Regulation: 4.6.2.3(3)(a)] without resorting to switching-off the lines. The bus reactors may also be provided at generation switchyards to supplement reactive capability of generators. The size of reactors should be such that under steady state condition, switching on and off of the reactors shall not cause a voltage change exceeding 5%. The standard sizes (MVAr) of reactors are:

Voltage Level	Standard sizes of reactors (in MVAr)
132 kV (3-ph unit)	12.5 and 25 (rated at 145 kV)
220 kV (3-ph unit)	50, 25 (rated at 245 kV)
400 kV (3-ph unit)	50, 63, 80,125 and 250 (rated at 420 kV)
765 kV (1-ph unit)	80 and 110 (rated at 765/√3 kV)

ii. Fixed line reactors may be provided to control power frequency temporary over-voltage (TOV) after all voltage regulation action has taken place within the limits as defined in Regulation 4.6.2.3(3)(b) under all probable operating conditions.

iii. Line reactors (switchable/ controlled/ fixed) may be provided if it is not possible to charge EHV line without exceeding the maximum voltage limits given in Regulation 4.6.2.3(3)(b). The possibility of reducing pre-charging voltage of the charging end shall also be considered in the context of establishing the need for reactors.

iv. The line reactors may be planned as switchable wherever the voltage limits, without the reactor(s), remain within limits specified for TOV conditions given at Regulation 4.6.2.3(3)(b).

d) Shunt FACTS devices

i. Shunt FACTS devices such as Static VAr Compensation (SVC) and STATCOM shall be provided where found necessary to damp the power swings and provide the system stability under conditions defined in the 'Reliability Criteria' [Regulation 4.6.2.3(4)]. As far as possible, the dynamic range of static compensators shall not be utilized under steady state operating condition.

e) Synchronous Condenser

i. A synchronous condenser (SC) is a synchronous machine operating without a prime mover. Reactive power output regulation of SC is performed by regulating the excitation current. The level of excitation determines if the synchronous condenser generates or consumes reactive power. SC provides improved voltage regulation and stability by continuously generating/absorbing reactive power, improved short-circuit strength and frequency stability by providing inertia.

ii. The conventional power stations could be refurbished to a synchronous condenser, thereby potentially reducing initial capital cost. A synchronous condenser consumes a small amount of active power from the system to cover losses. As many gas and coal-based synchronous generators approach the end of their life, the retiring of a plant can possibly create a reactive power deficit at the local network, which may impact voltage stability. The conversion of the existing generator to a synchronous condenser can be potentially economical and effective.

iii. Operating Hydro generators in synchronous condenser mode may be a possible way for voltage control with the existing resources, which may be explored to regulate voltage in grid locally and thus, preventing the switching of other elements for voltage control purpose, which in turn help in keeping the system reliability intact.

7. ADDITIONAL CRITERIA

a) Wind / Solar / Hybrid projects

i. All the generation projects based on renewable energy sources shall comply with Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 and its amendments or re-enactment thereof, for which requisite system studies shall be carried out by renewable generation project developer.

ii. Connectivity quantum shall be considered while planning the evacuation system, both for immediate connectivity with InSTS and for onward transmission requirement.

iii. As the generation of energy at a wind farm is possible only with the prevalence

of wind, the thermal line loading limit of the lines connecting the wind farms to the pooling substations may be assessed considering 12 km/hour wind speed.

b) HVDC Transmission System

i. The option of HVDC bipole may be considered for transmitting bulk power (more than 2000 MW) over long distance (preferably more than 700 km). HVDC transmission may also be considered in the transmission corridors that have AC lines carrying heavy power flows (total more than 5000 MW) to control and supplement the AC transmission network.

ii. The ratio of fault level in MVA at any of the convertor station (for conventional current source type), to the power flow on the HVDC bipole shall not be less than 3.0 under any of the load-generation scenarios given in Chapter-4 and reliability criteria given at Regulation 4.6.2.3(4). Further, in areas where multiple Conventional HVDC bipoles are feeding power (multi-infeed), the appropriate studies may be carried at planning stage so as to avoid commutation failure.

c) Zone-3 settings

i. The transmission utilities shall ensure that zone-3 relay settings of the transmission lines are such that they do not trip at extreme loading of line. For this purpose, the extreme loading may be taken as 120% of thermal current loading limit and assuming 0.9 per unit voltage (i.e., 360 kV for 400 kV system, 689 kV for 765 kV system). In case it is not practical to set the Zone-3 in the relay to take care of above, the transmission licensee/owner shall inform CEA, CTU/STU and RLDC/SLDC along with setting (primary impendence) value of the relay. Mitigating measures shall be taken at the earliest and till such time the permissible line loading for such lines would be limited to as calculated from relay impedance assuming 0.95 pu voltage, provided it is permitted by stability and voltage limit considerations as assessed through appropriate system studies.

d) Resiliency

i. The IEEE Technical Report PES-TR65 defines resilience as “The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event”. This may also be simply defined as “The ability to protect

against and recover from any event that would significantly impact the grid".

ii. Resilience v/s Reliability:

The IEEE defines Reliability as "The probability that a system will perform its intended functions without failure, within design parameters, under specific operating conditions, and for a specific period of time." Further different utilities worldwide have defined and developed different reliability standards for robustness, resourcefulness, rapid recovery and adaptability of their power systems.

The IEEE Technical Report PES-TR83 states that reliability is a system performance measure, and resilience is a system characteristic. Generally better reliability results in better resilience and vice versa. However, in some cases, a highly reliable system may have lower resilience and vice versa. The primary difference between reliability and resilience is that resilience encompasses all events, including "High Impact — Low Frequency" events commonly excluded from the reliability calculations.

iii. Resilience Evaluation: Several frameworks and methods for advancing resilience evaluation have been developed in the last decade. These frameworks can be grouped into two general categories: qualitative and quantitative frameworks.

I. Qualitative Frameworks: Qualitative frameworks usually evaluate the power system's resilience, along with other interdependent systems, such as information systems, fuel supply chain, and other such infrastructures. These frameworks evaluate resilience capabilities such as preparedness, mitigation, response, and recovery. Qualitative frameworks are appropriate for long-term planning because they provide a comprehensive and holistic depiction of system resilience.

II. Quantitative Frameworks: Quantitative frameworks are based on the quantification of system performance. Resilience is quantitatively evaluated based on the reduced magnitude and duration of deviations from the targeted or acceptable performance. Quantitative resilience metrics should be: 1) performance-related, 2) event-specific, 3) capable of considering uncertainty, and 4) useful for decision-making.

An effective resiliency framework should strive to minimize the likelihood and impacts of a disruptive event from occurring and provides the right guidance and resources to respond and recover effectively and efficiently when an incident happens. This can be accomplished by applying the framework towards assessing and developing a mitigation program with the five main focus areas: Prevention, Protection, Mitigation, Response, and Recovery.

III. The Recommended Measures in the "Report of Task Force on Cyclone Resilient Robust Electricity Transmission and Distribution Infrastructure in the Coastal Areas" accepted by Ministry of Power vide letter dated 10th June, 2021 for Creating Resilient Transmission Infrastructure may be referred.

8. Electrical Clearances:

a) The following minimum safety working clearance shall be maintained for the bare conductors or live parts of any apparatus in outdoor substation, excluding overhead lines of HV and EHV installation. (As per CEA notification of 20th Sept, 2010 Measures relating to Safety and Electric Supply, clause no. 44(2)-(iii)):

High System Voltage (kV)	**Safety Working Clearance (in Metres)**
12	2.6
36	2.8
72.5	3.1
145	3.7
High System Voltage (kV)	**Safety Working Clearance (in Metres)**
145	3.7
245	4.3
420	6.4
800	10.3

b) Clearance above ground of the lowest conductor (as per CEA notification of 20th Sept,2010, clause no.58 on Measures relating to Safety and Electric Supply):

i) No conductor of an overhead line, including service lines, erected across a streetshall at any part thereof be at a height of less than

(a)	For low and medium voltage lines:	5.8 metres
(b)	For high voltage lines	6.1 metres

ii) No conductor of an overhead line, including service lines, erected along any street,shall at any part thereof be at a height less than

(a)	For low and medium voltage lines	5.5 metres
(b)	For high voltage lines	5.8 metres

iii) No conductor of an overhead line including service lines, erected elsewhere thanalong or across any street shall be at a height less than –

(a)	For low, medium and high voltages lines up to and including 11kV, if bare	4.6 metres
(b)	For low, medium and high voltage lines up to and including 11kV, if insulated	4.0 metres
(c)	For high voltage lines above 11kV	5.2 metres

iv) For extra-high voltage lines, the clearance above ground shall not be less than 5.2 metres plus 0.3 metres for every 33,000 volts or part thereof, by which the voltage of the line exceeds 33,000 volts:

Provided that the minimum clearance along or across any street shall not be less than 6.1 metres.

c) Clearance from building of high and extra-high voltage lines (as per CEA notification of20th Sept, 2010, clause no. 61)

i. Where a high or extra-high voltage overhead line passes above or adjacent to any building or part of a building, it shall have on the basis of maximum sag, a vertical clearance above the highest part of the building immediately under such line, of not less than

(a)	For HV lines up to and including 33kV	3.7 metres
(b)	For EHV lines	3.7 metres plus 0.3 metres forevery additional 33 kV or part thereof

ii. The horizontal clearance between the nearest conductor and any part of such building shall, on the basis of maximum deflection due to wind pressure, be not less than-

(a)	For HV lines up to and including 11kV	1.2 metres
(b)	For HV lines above 11kV and up to andincluding 33kV	2.0 metres
(c)	For EHV lines	2.0 metres plus 0.3 metres for every additional 33kV or part thereof

[Explanation: for the purpose of this rule, the expression "building" shall be deemed to include any structure, whether permanent or temporary.]

Various voltage class transmission line crossing or approaching each other. (As per CEA notification of 20th Sept, 2010, Clause no. 69 (IV))

(in metres)

Sr. No.	Nominal System voltage	11-66 kV	110-132 kV	220kV	400kV	800kV
1	Low and Medium	2.44	3.05	4.58	5.49	7.94
2	11-66 kV	2.44	3.05	4.58	5.49	7.94
3	110-132kV	3.05	3.05	4.58	5.49	7.94
4	220 kV	4.58	4.58	4.58	5.49	7.94
5	400 kV	5.49	5.49	5.49	5.49	7.94
6	800 kV	7.94	7.94	7.94	7.94	7.94

Once the Resource Adequacy Regulations are notified by the Commission, the provisions of the same shall prevail to the extent of inconsistency and overlap of any provision contained in this Chapter of these Regulations.

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5 Connection Code

5.1 Compliance with existing Rules and Regulations

(1) All Users connected to or seeking connection to the grid shall comply with all the applicable Regulations as enacted or amended from time to time, such as:

(a) Central Electricity Authority (Technical Standards for Connectivity to the Grid)Regulations, 2007;

(b) Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022;

(c) Central Electricity Authority (Measures Relating to Safety & Electric Supply)Regulations, 2023;

(d) Central Electricity Regulatory Commission (Communication System for Inter-StateTransmission of Electricity) Regulations, 2017;

1. Guidelines Availability of Communication System (Order – date 19.01.2024)
2. Guidelines Interfacing Requirements (Order - date 19.01.2024)

(e) Central Electricity Authority (Installation and Operation of Meters) Regulations, 2006;

(f) GERC (Terms and Conditions of Intra-State Open Access) Regulations, 2011 and GERC (Terms and Conditions for Green Energy Open Access) Regulations, 2024.

(g) Gujarat Electricity Regulatory Commission (Multi-Year Tariff Regulations), 2024

(h) Central Electricity Authority (Technical Standards for Communication System in Power System Operation) Regulations, 2020;

(i) Central Electricity Authority (Grid Standards) Regulations, 2010.

(j) Central Electricity Authority (Cyber Security in Power Sector) Guidelines, 2021.

(k) Central Electricity Authority (Flexible Operation of Coal based Thermal

PowerGenerating Units) Regulations, 2023

(l) The Information Technology Act, 2000

(m) Guidelines on Unified Philosophy for Placement of Phasor measurement Unit in Indian Grid, March 2025

(n) Any other Regulations and Standards, Codes as specified from time to time.

5.2 Scope

The connection code applies to STU, Transmission Licensees, and all Users connected to or seeking connection to the Gujarat Grid and embedded in the intra-state systems.

5.3 Procedure for connection

1. A user seeking to establish new or modified arrangement of connection to or for use of Gujarat Grid, shall submit an application in standard format to STU in accordance with Gujarat Electricity Regulatory Commission (Terms and Conditions for Intra-state Open Access) Regulations, 2011, GERC (Terms and Conditions for Green Energy Open Access) Regulations, 2024 and GERC (Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources) Regulations, 2019 as amended from time to time.

2. SLDC, in coordination with STU, and after due consultation of stakeholders, shall prepare a detailed procedure covering modalities for first time energization and integration of new or modified power system element and submit the same for approval of the Commission. The procedure shall specify requirements for integration with the grid such as protection, telemetry and communication systems; metering; statutory clearances; modelling data requirements for system studies and timeline for submission of data for system study. In the absence of such procedure of SLDC, the NLDC procedure shall apply.

3. Post completion of all physical arrangements of connectivity and necessary site tests, the concerned user shall request the SLDC for permission of first-time energization in the specified format as per the procedure published by SLDC.

5.4 Connection Agreement

1. The applicant with STU or with Distribution Licensee, as the case may be, in accordance with the Gujarat Electricity Regulatory Commission (Terms and Conditions for Intra-state Open Access) Regulations, 2011 and/or GERC (Terms and Conditions for Green Energy Open Access) Regulations, 2024, as amended from time to time shall sign a connection agreement.

2. The Procedure for Connection Agreement shall be prepared by SLDC and submitted to the Commission for approval.

5.5 Important Technical Requirements for Connectivity to the Grid:

1. SLDC in consultation with STU shall carry out a joint system study six (6) months before the expected date of first energization of a new power system element to identify operational constraints, if any. In case of constraints, SLDC shall identify measures for facilitating the integration of the element, subject to grid security.

5.5.1 Reactive Power Compensation

a) Reactive Power compensation and/or other facilities shall be provided by STUs, and Users connected to Gujarat Grid as far as possible in the low voltage systems close to the load points, thereby avoiding the need for exchange of Reactive Power to/from Gujarat Grid and to maintain Gujarat Grid voltage within the specified range.

b) Switched Shunt Reactors at 220 kV and above may be provided to control over-voltage within the limits.

c) The person already connected to the grid shall also provide additional reactive compensation as per the quantum and time frame decided by SLDC and WRPC. The Users and STUs shall provide information to WRPC and WRLDC regarding the installation and healthiness of the reactive compensation equipment on regular basis.

5.5.2 Data and Communication Facilities

a) Reliable speech and data communication systems shall be provided to facilitate necessary communication, data exchange, supervision and control of the grid by the SLDC in accordance with the CERC

(Communication System for Inter- State Transmission of Electricity) Regulations, 2017 and the CEA Technical Standards for Communication 2020 as amended from time to time.

b) All Users, STUs and CTU shall provide systems to telemeter power system parameters such as flow, voltage and status of switches/ transformer taps, etc., in line with interface requirements and other guideline made available by SLDC. All users, STU shall provide data collection and data communication up to Sub-SLDC/SLDC as specified in the connection agreement.

c) The concerned user as specified by STU in the connection agreement shall also establish the associated communication system to facilitate data flow up to appropriate Sub-SLDC/ SLDC including all interface requirement as mentioned in CEA Guidelines on under the Central Electricity Regulatory Commission (Communication System for inter-State transmission of electricity) Regulations, 2017 as amended from time to time and Guidelines Interfacing Requirements (Order - date 19.01.2024).

d) All Users shall provide, in coordination with STU, the required facilities at their respective ends as specified in the connectivity agreement. All Users, STU to ensure high reliability of the communication links, shall monitor real time data communication in real time as mentioned in CEA Guidelines on under the Central Electricity Regulatory Commission (Communication System for inter-State transmission of electricity) Regulations, 2017 as amended from time to time and Guidelines Availability of Communication System (Order - date 19.01.2024).

5.5.3 System Recording Instruments

Recording instruments such as Data Acquisition System/Disturbance Recorder/Event Logging Facilities/Fault Locator (including time synchronization equipment) shall be provided and always kept in working condition in the Gujarat Grid for recording of dynamic performance of the system. All Users and STUs shall provide all the requisite recording instruments and keep them in working condition (the facility of system recording shall be provided for verifying the events if any occurred and as the evidence if any events occurred which affected grid operation and

management on real time basis.)

5.5.4 Responsibilities for Safety

STU and the concerned Users shall be responsible for safety in accordance with Central Electricity Authority (Technical Standards for connectivity to the Grid) Regulations, 2007, and other applicable Regulations/ Codes notified by CEA and the Commission from time to time and amended in it.

5.5.5 Cyber Security

All Users shall have in place and follow, a cyber-security framework in accordance with the Central Electricity Authority (Cyber Security in Power Sector) Guidelines, 2021 and as amended from time to time to identify the critical cyber assets and protect them to support reliable operation of the grid.

5.5.6 Wind, Solar and Hybrid of Wind and Solar generators using invertors and also connected with or without Battery Energy Storage System:

The connectivity standards specifying the technical requirements for RE generating stations (Wind, Solar, Wind-Solar Hybrid with or without Energy Storage System (ESS)), Standalone ESS to be synchronized with the grid at 33 kV or above. They shall be capable of the following:

1. RE generating stations and ESS connected at 33 kV and above shall be capable of supplying dynamically varying reactive power support, so as to maintain power factor within limits of 0.95 lagging to 0.95 leading as per the system requirement. Similarly, solar generating stations have to maintain power factor within limits of 0.90 lagging to 0.90 leading as per system requirement.

2. RE generating stations and ESS shall comply the Central Electricity Authority (Technical Standards for Connectivity to the Grid) (Amendment) Regulations, 2019 as amended from time to time on connectivity standards applicable to the wind generating stations, generating stations using inverters, wind - solar photo voltaic hybrid systems and energy storage systems so that grid is not destabilized due to sudden outage of generation in the event of a grid disturbance.

3. The total harmonic distortion for voltage at the connection point shall

not exceed 5% with no individual harmonic higher than 3% and the total harmonic distortion for current drawn from the transmission system at the connection point shall not exceed 8%. The above measurement of Harmonics Distortion has to be carried out every six monthly and shall be reported to STUs/ Licensees.

5.6 Schedule of Assets of State Grid

STU shall collect and submit a schedule of transmission assets of Intra-State Transmission Licensees annually to the Commission by 30th September each year, which constitutes the State grid as on 31st March of that year indicating ownership.

5.7 Metering for Open Access

The open access consumer, generating company, Distribution Licensee and traders shall provide meters, as may be specified by the Commission in Gujarat Electricity Regulatory Commission (Terms and Conditions for Intra-state Open Access) Regulations, 2011 and Green Energy Open Access Regulations, 2024 as amended from time to time.

5.8 Commissioning of Connectivity

(1) The commissioning of all the new projects shall be governed as per Chapter 7 of the Grid Code.

(2) The applicant and all Intra-State Transmission Licensees shall comply with the provisions made in the Connection Agreement, CEA Technical Standards for Communication Regulations and amendments thereof and other relevant Regulations of CEA, Order/Regulation of Commission, CERC, and IEGC as amended from time to time.

(3) Special focus shall be made on technical requirements for connectivity to the grid, i.e., voice and data communication facilities, system recording instruments, protection, responsibilities for safety, cyber security, reactive power compensation, integration of data with SLDC and STU, SCADA and other provisions.

(4) Installation of meters, its testing, calibration and reading and all matters incidental thereto shall be undertaken in conformity with CEA Metering Regulations and amendments thereof, Scheduling and Despatch Code of

this Grid Code and any other additional requirement as may be considered necessary by STU.

(5) The applicant shall intimate timeline for commissioning of works at its end and of dedicated transmission line up to the point of connectivity at least three months in advance.

(6) In case of Generating Stations, date of synchronization of Generating Station and Transmission Line shall be intimated at least _10 days in advance so that required clearances, charging permission, issue of unique charging code could be issued by SLDC in consultation with STU and respective Intra-State Transmission Licensee.

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6 Protection Code

6.1 General

This chapter covers the protection protocol, protection settings and protection audit plan of electrical systems.

1. There shall be a uniform protection protocol for the Users of the grid:

   a) for proper co-ordination of protection system in order to protect the equipment/system from abnormal operating conditions, isolate the faulty equipment and avoid unintended operation of protection system;

   b) To have a repository of protection system, settings and events at State / Regional level;

   c) specifying timelines for submission of data;

   d) To ensure healthiness of recording equipment including triggering criteria and time synchronization; and

   e) To provide for periodic audit of protection system.

2. STU shall be guided by the advice of WRPC / WRLDC for the following:

   a) Planning for upgrading and strengthening protection system based on analysis of grid disturbance and partial/total blackout in State Transmission System.

   b) Planning of Islanding and system split schemes and installation of Under Frequency Relays and df/dt relays.

3. Under-Frequency relay for load shedding, relays provided for islanding scheme, disturbance recorder, and fault locator installed at various sub-stations shall be tested and calibrated. All Users shall ensure correct and appropriate settings of protection equipment.

4. Protection settings shall not be altered or protection by passed and/or disconnected without consultation and agreement of all affected Users. In the case where protection is bypassed and/or disconnected, by agreement, then the cause must be rectified, and the protection restored to normal condition as quickly as possible. If agreement has not been reached, the

electrical equipment will be removed from service forthwith.

5. No item of electrical equipment shall be allowed to remain connected to the State Transmission System unless it is covered by minimum specified protection aimed at reliability, selectivity, speed and sensitivity.

6.2 Protection Co-ordination

A Protection Coordination Committee (PCC) shall be constituted under these Regulations and shall be responsible for all the protection coordination functions. STU shall be responsible for arranging periodical meetings of the Protection Coordination Committee. STU shall investigate any malfunction of protection or other unsatisfactory protection issues. Users shall take prompt action to correct any protection malfunction or issue as discussed and agreed to, in the periodical meetings.

6.3 Protection Protocol

1. All Users connected to the integrated grid shall provide and maintain effective protection system having reliability, selectivity, speed and sensitivity to isolate faulty section and protect element(s) as per the CEA Technical Standards for Construction,the CEA Technical Standards for Connectivity, the CEA (Grid Standards) Regulations, 2010, the CEA Technical Standards for Communication and any other applicable CEAStandards specified from time to time.

2. Back-up protection system shall be provided to protect an element in the event of failure of the primary protection system.

3. Protection Coordination Committee (PCC) shall develop the protection protocol and revise the same, after review from time to time, in consultation with the stakeholders in the State, and in doing so shall be guided by the principle that minimum electrical protection functions for equipment connected with the grid shall be provided as per CEA Technical Standards for Connectivity Regulations, CEA Grid Standards Regulations, CEA Technical Standards for Communication Regulations, CEA Technical Standards for Construction Regulations, CEA Safety Regulations and amendments thereof and any other CEA standards specified from time to time.

4. The protection protocol framed by concerned RPC in accordance with the principle that minimum electrical protection functions for equipment connected with the grid and as per the CEA Technical Standards for Construction, the CEA Technical Standards for Connectivity, the CEA Technical Standards for Communication, the CEA (Grid Standards) Regulations, 2010, the CEA (Measures relating to Safety and Electric Supply) Regulations, 2010, and any other CEA standards specified from time to time, shall be followed.

5. The protection protocol in a particular system may vary depending upon operational experience. Changes in protection protocol, as and when required, shall be carried out after deliberation and approval of the concerned RPC.

6. In line with the protection protocol of RPC, STU shall prepare the Protection Manual within 90 days from the notification of these Regulations in consultation with the PCC and stakeholders covering all the protection aspects of the grid elements connected to 66 kV and above voltage level which shall be followed by all Users.

7. Violation of the protection protocol, if any, identified by STU, shall be brought to the notice of the PCC for appropriate / corrective action.

6.4 Protection Settings

1. STU shall undertake review of the protection settings, assess the requirement of revisions in protection settings and revise protection settings in consultation with the stakeholders from time to time and at least once in a year. The necessary studies in this regard shall be carried out by the STU. The data including demand profile for base case (peak and off-peak cases) for carrying out studies shall be provided by SLDC and DISCOMs to STU.

2. All Users connected to the grid shall:

   (a) furnish the protection settings implemented for each element to STU in a format as prescribed by the STU;

   (b) obtain approval of STU for (i) any revision in settings, and (ii) implementation of new protection system;

   (c) intimate to the STU about the changes implemented in protection system or

protection settings within a fortnight of such changes;

(d) Ensure correct and appropriate settings of protection as specified by the STU / WRPC.

(e) Ensure proper coordinated protection settings.

3. Protection Coordination Committee (PCC) shall:

(a) maintain a centralised database and update the same on periodic basis in respect of State containing details of relay settings for grid elements connected to 66 kV and above. SLDC shall also maintain such database.

(b) carry out detailed system studies once in a year, for protection settings and advice modifications / changes, if any, to STU and all Users. The data required to carry out such studies shall be provided by SLDC, STU and Users, as the case may be.

(c) provide the database access to STU and SLDC and to all Users of the State. The database shall have different access rights for different Users.

(d) The changes in the network and protection settings of grid elements connected to 66 kV and above shall be informed to Protection Coordination Committee (PCC) by SLDC and STU, as the case may be.

6.5 Protection Audit Plan

1. All Users shall conduct internal audit of their protection systems annually, and any shortcomings identified shall be rectified and informed to STU. The audit report along with action plan for rectification of deficiencies detected, if any, shall be shared with STU.

2. All Users shall also conduct third party protection audit of each sub-station at 132 kV and above once in five years or earlier as advised by the WRPC.

3. After analysis of any event, STU shall identify a list of substations / and generating stations where third-party protection audit is required to be carried out and accordingly advise the respective Users to complete third party audit within three months.

4. The third-party protection audit report shall contain information sought in the format enclosed as **Annexure–2.** The protection audit reports, along with action plan for rectification of deficiencies detected, if any, shall be submitted to the STU as well as PCC within a month of submission of third-party audit report. The necessary compliance to such protection audit report shall be followed up regularly by STU and shall be reported to PCC.

5. Annual audit plan for the next financial year shall be submitted by the Users to their respective STU by 31st October. The Users shall adhere to the annual audit plan and report compliance of the same to STU.

6. Users shall submit the following protection performance indices of previous month to STU and SLDC on monthly basis for 132 kV and above, which shall be reviewed by the STU:

    a. The Dependability Index defined as $D = N_c / (N_c + N_f)$

    b. The Security Index defined as $S = N_c / (N_c + N_u)$

    c. The Reliability Index defined as $R = N_c / (N_c + N_i)$

    where,

    N_c is the number of correct operations at internal power system faults

    N_f is the number of failures to operate at internal power system faults.

    N_u is the number of unwanted operations.

    N_i is the number of incorrect operations and is the sum of N_f and N_u

7. Each user shall also submit the reasons for performance indices less than unity of individual element wise protection system to STU and SLDC and action plan for corrective measures. The action plan will be followed up regularly by the STU and SLDC.

8. In case any user fails to comply with the protection protocol specified by the RPC PCC / STU or fails to undertake remedial action identified by the RPC / PCC / STU within the specified timelines, the STU may approach the Commission with all relevant details for suitable directions.

6.6 System Protection Scheme (SPS)

1. For the operational SPS, SLDC in consultation with the STU shall perform regular load flow and dynamic studies and mock testingfor reviewing SPS parameters and functions, at least once in a year. SLDC shall share the report of such studies and mock testing including any shortcomings to STU.

2. The Users and SLDCs shall report about the operation of SPS immediately and detailed report shall be submitted within three days of operation to the PCC and RLDC in the format specified by the STU / PCC.

3. The performance of SPS shall be assessed as per the protection performance indices specified in these Regulations. In case, the SPS fails to operate, the concerned User shall take corrective actions and submit a detailed report on the corrective actions taken to the PCC, STU, SLDC and RPC within a fortnight.

6.7 Recording Instruments

1. All Users shall keep the recording instruments (disturbance recorder and event logger) in proper working condition.

2. The disturbance recorders shall have time synchronization and a standard format for recording analogue and digital signals, which shall be included in the guidelines issued by the STU / PCC.

3. The time synchronization of the disturbance recorders shall be corroborated with the PMU data or SCADA event loggers by SLDC. Disturbance recorders that are non- compliant shall be listed out for discussion at SOCC / PCC.

6.8 Capacity Building and Certification

Capacity building, skill up-gradation, and certification of the personnel deployed in Generating Stations, Load Despatch Centres and EHV Sub-stations shall be done periodically under an institutional framework through accredited certifying agencies.

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7 Commissioning and Commercial Operation Code

7.1 Drawal of Start Up Power and Injection of Infirm Power

1. A unit of a generating station including unit of a captive generating plant that has been granted connectivity to the intra-State System in accordance with Open Access Regulations shall be allowed to inter-change power with the grid during the commissioning period, including testing and full load testing before the COD, after obtaining prior permission of SLDC subject to provisions of applicable Order / Regulations of the Commission / PPA with DISCOMs and procedures approved by the Commission in this regard:

   Provided that SLDC while granting such permission shall keep grid security in view.

2. The period for which such inter-change shall be allowed shall be as follows:

   a. Drawal of start-up power shall not exceed fifteen (15) months prior to the expected date of first synchronization and one (1) year after the date of first synchronization;

   b. Injection of infirm power shall not exceed one (1) year from the date of first synchronization for generating stations other than REGS and ESS (except Hydro PSP ESS).

   c. Injection of infirm power shall not exceed seven (7) days before the date of FTC (First Time Charging) approval and seven (7) days after FTC (First Time Charging) approval for REGS and ESS (except Hydro PSP ESS):

      Provided that injection of infirm power shall be allowed for prototype without any payment as it is inadvertent power.

3. Drawal of start-up power shall be regulated as under:

   a. In case there is an existing PPA, the drawal of start-up power shall be accounted in the manner stipulated in the PPA;

   b. In case there is no existing PPA, the start-up energy drawal shall be accounted in the manner stipulated in the applicable Order/Regulations of the Commission;

   c. In the absence of existing PPA and any method stipulated in the

applicable Order/Regulations of the Commission, the generating Unit/Station shall procure the power from the concerned Distribution Licensee.

4. Drawal of start-up power shall be subject to payment of transmission charges as applicable to STOA;

5. The charges for deviation for drawal of startup power or for injection of infirm power shall be as per the Orders issued by the Commission from time to time;

6. Start-up power shall not be used by the generating station for construction activities;

7. SLDC shall stop the drawal of the start-up power in the following events:

   a. In case, it is established that the start-up power has been used by the generating station for construction activity;

   b. In the case of default in payment of monthly transmission charges, deviation charges approved by the Commission and in absence of Commission approved rates, CERC DSM Regulations as amended from time to time shall be utilized.

7.2 Data to be furnished prior to notice of Trial Run

The following details, as applicable, shall be furnished by each State entity generating station to SLDC, STU, DISCOMs and the beneficiaries of the generating station, prior to notice of trial run:

Table 1: Details To Be Furnished By Generating Entity Prior To Trial Run

Description	Units
Installed Capacity of generating station	MW
Installed Capacity of generating station	MVA
MCR	MW
Number x unit size	No x MW
Time required for cold start	Minute
Time required for warm start	minute
Time required for hot start	Minute

Description	Units
Time required for combined cycle operation under cold conditions	Minute
Time required for combined cycle operation under warm conditions	Minute
Ramping up capability	% per minute
Ramping down capability	% per minute
Minimum turndown level	% of MCR
Minimum turndown level	MW (ex-bus)
Inverter Loading Ratio (DC/AC capacity)	
Name of QCA (where applicable)	
Full reservoir level (FRL)	Metre
Design Head	Metre
Minimum draw down level (MDDL)	Metre
Water released at Design Head	M^3/ MW
Unit-wise forbidden zones	MW
Real time telemetry MOM	RTU/ SCADA
Communication System for RTU	OPGW/PTP/MPLS

7.3 Notice of Trial Run

1. The generating company proposing its generating station or a unit thereof for trial run or repeat of trial run shall give a notice of not less than seven (7) days to the SLDC, and the beneficiaries of the generating stations, including intermediary procurers, wherever identified:

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

2. The transmission licensee proposing its transmission system or an element thereof for trial run shall give a notice of not less than seven days to the SLDC, STU, distribution licensees of the State and the owner of the inter-connecting system.

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

4. A generating station shall be required to undergo a trial run in accordance with Regulation 7.4 of these Regulations after completion of Renovation and Modernization for extension of the useful life of the project as per the applicable GERC Tariff Regulations as amended from time to time.

7.4 Trial Run of Generating Unit

7.4.1 Trial run of thermal generating unit:

Trial Run of the Thermal Generating Unit shall be carried out in accordance with the following provisions:

a. A thermal generating unit shall be in continuous operation at MCR for seventy-two (72) hours on designated fuel:

   Provided that:

   (i) short interruption or load reduction shall be permissible with the corresponding increase in duration of the test;

   (ii) interruption or partial loading may be allowed with the condition that the average load during the duration of the trial run shall not be less than MCR, excluding the period of interruption but including the corresponding extended period.

   (iii) Cumulative interruption of more than four (4) hours shall call for a repeat of trial run.

b. Where, on the basis of the trial run, a thermal generating unit fails to demonstrate the unit capacity corresponding to MCR, the generating company has the option to de-rate the capacity of the generating unit or to go for a repeat trial run. If the generating company decides to de-rate the unit capacity, the de-rated capacity in such cases shall not be more than 95% of the demonstrated capacity, to cater for primary response.

7.4.2 Trial Run of Hydro Generating Unit:

The trial Run of Hydro Generating Unit shall be carried out in accordance with the following provisions:

a. A hydro generating unit shall be in continuous operation at MCR for twelve (12) hours,

Provided that:

i. Short interruption or load reduction shall be permissible with a corresponding increase in duration of the test;

ii. Interruption or partial loading may be allowed with the condition that the average load during the duration of trial run shall not be less than MCR excluding period of interruption but including the corresponding extended period;

iii. cumulative interruption of more than four (4) hours shall call for a repeat of trial run;

iv. if it is not possible to demonstrate the MCR due to insufficient reservoir or pond level or insufficient inflow, COD may be declared, subject to the condition that the same shall be demonstrated immediately when sufficient water is available after COD:

Provided that if such a generating station is not able to demonstrate the MCR when sufficient water is available, the generating company shall de-rate the capacity in terms of sub-clause (b) of this Regulation, and such de-rating shall be effective from COD.

b. Where, on the basis of the trial run, a hydro generating unit fails to demonstrate the unit capacity corresponding to MCR, the generating company shall have the option to either de-rate the capacity or go for a repeat trial run. If the generating company decides to de-rate the unit capacity, the de-rated capacity in such cases shall not be more than 90% of the demonstrated capacity to cater for primary response.

7.4.3 Trial Run of Wind / Solar / ESS / PSP/Hybrid Generating Station

1. Trial run of solar unit(s)

a. Trial run of the solar inverter unit(s) shall be performed for a minimum capacity aggregating to above 4 MW AC capacity:

Provided that the trial run for entire capacity shall be performed in a maximum of four instalments:

Provided further that the trial run for solar inverter unit(s) aggregating to

less than and up to 4 MW, shall be allowed for the capacity for which Connectivity has been granted to such entity.

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

Provided that:

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

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

Provided that if such a generating station is not able to demonstrate the rated capacity when sufficient solar irradiation is available after COD, the generating company shall de-rate the capacity in terms of sub-clause (d) of Regulation 7.4.3.(3) of these Regulations.

2. Trial run of a wind turbine(s)

a. Trial run of a wind turbine(s) shall be performed for a minimum capacity aggregating to above 4 MW:

Provided that the trial run for wind turbine(s) above the capacity of above 4 MW shall be performed in maximum four batches:

Provided further that the trial run for wind turbine(s) aggregating to less than or upto 4 MW shall be allowed for the capacity for which connectivity has been granted to such an entity.

b. Successful trial run of a wind turbine(s) covered under sub-clause (a) of this Regulation shall mean the flow of power and communication signal

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

Provided that:

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

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

Provided that if such a generating station is not able to demonstrate the rated capacity when sufficient wind velocity is available after COD, the generating company shall de-rate the capacity in terms of sub-clause (d) of Regulation 7.4.3 (3) these Regulations.

3. Trial run of a standalone Energy Storage System (ESS) / Pumped storage plant / Hybrid system

a. Successful trial run of a standalone Energy Storage System (ESS) having capacity above 4 MW shall mean one (1) cycle of charging and discharging of energy as per the design capabilities withthe requisite metering, telemetry and protection system being in service.

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

Provided that if it is not possible to demonstrate the design capabilities up to the rated water drawing levels due to insufficient reservoir levels, the COD may be declared after demonstrating the capabilities at available water drawing levels, subject to the condition that design capabilities up to the rated water drawing levels shall be demonstrated immediately when sufficient reservoir level

is available after COD:

Provided further that if such a generating station is not able to demonstrate the design capabilities when sufficient water is available, the generating company shall have the option to either go for a repeat trial run or de-rate the capacity. If the generating company decides to de-rate the unit capacity in terms of sub-clause (b) of Regulation (7.4.2) of these Regulations, such de-rating shall be effective from the COD."

c. Successful trial run of a hybrid system shall mean successful trial run of each individual source of the hybrid system in accordance with the applicable provisions of these Regulations.

d. Where, on the basis of the trial run, solar / wind / storage / hybrid generating station fails to demonstrate its rated capacity, the generating company shall have the option to either go for a repeat trial run or de-rate the capacity subject to a minimum aggregated de-rated capacity above 4 MW _ as the case may be.

e. Notwithstanding the provisions contained in these Regulations, where Power Purchase Agreement provides for a specific capacity that can be declared COD, trial run shall be allowed for such capacity in terms of such Power Purchase Agreement.

7.5 Trial run of Intra-State Transmission System

1. Trial run of a transmission system or an element thereof shall mean successful energization of the transmission system or the element thereof at its nominal system voltage through interconnection with the grid for a continuous twenty-four (24) hours flow of power and communication signal from the sending end to the receiving end and with the requisite metering system, telemetry and protection system:

   Provided that under exceptional circumstances and with the prior approval of STU / SLDC,a transmission element can be energized at lower nominal system voltage level:

   Provided further that the SLDC may allow anti-theft charging where the transmission line is not carrying any power.

7.6 Documents and Tests prior to Declaration of Commercial Operation

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

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

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

a. The generating company shall submit the following OEM documents, namely (i) startup curve for boiler and turbine including starting time of unit in cold, warm and hot conditions, (ii) capability curve of generator, (iii) design ramp rate of boiler and turbine.

b. The following tests shall be performed:

   i. Operation at a load of fifty-five (55) percent of MCR as per the CEA Technical Standards for Construction for a sustained period of four (4) hours.

   ii. Ramp-up from fifty-five (55) percent of MCR to MCR at a ramp rate of at least one (1) percent of MCR per minute, in one step or two steps (with stabilization period of 30 minutes between two steps), and sustained operation at MCR for one (1) hour.

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

   iv. Ramp-down from MCR to fifty-five (55) percent of MCR at a ramp rate of at least one (1) percent of MCR per minute, in one or two steps (with stabilization period of 30 minutes between two steps).

v. Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz at 55%, 60%, 75% and 100% load.

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

7.6.2 Documents and Tests Required for Hydro Generating Stations including Pumped Storage Hydro Generating Station:

a. The generating company shall submit OEM documents for the turbine characteristics curve indicating the operating zone(s) and forbidden zone(s). In order to demonstrate the operating flexibility of the generating unit, it shall be operated below and above the forbidden zone(s).

b. The following tests shall be performed considering the water availability and head:

i. Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz for various loadings within the operating zone.

ii. Reactive power capability as per the generator capability curve considering over-excitation and under-excitation limiter settings.

iii. Black start capability, wherever feasible.

iv. Operation in synchronous condenser mode wherever designed.

7.6.3 Documents and Test Required for Gas Turbine based Generating Stations:

a. The generating company shall submit OEM documents for (i) starting time of the unitin cold, warm and hot conditions (ii) design ramp rate.

b. The following tests shall be performed:

i. Primary response through injecting a frequency test signal with a step change of ± 0.1 Hz for various loadings within the operating zone.

ii. Reactive power capability as per the generator capability curve considering over-excitation and under-excitation limiter settings.

iii. Black start capability up to 100 MW capacity, wherever feasible.

iv. Operation in synchronous condenser mode wherever designed.

7.6.4 Documents and Tests required for the Generating Stations based on wind and solar resources:

a. The generating company shall submit a certificate confirming compliance with CEA Technical Standards for Connectivity in accordance with sub-clause (4) of Regulation 7.8 of these Regulations.

b. The following tests shall be performed at the point of interconnection:

i. Frequency response of machines as per the CEA Technical Standards for connectivity.

ii. Reactive power capability as per OEM rating at the available irradiance or the wind energy, as the case may be:

Provided that the generating company may submit offline, simulation studies for the specified tests, in case testing is not feasible before COD, subject to the condition that tests shall be performed within a period of one year from the date of achieving COD.

7.6.5 Documents and Tests Required for Energy Storage Systems:

a. The ESS shall submit a certificate confirming compliance with the CEA Technical Standards for Connectivity in accordance with sub-clause (4) of Regulation 7.8 of these Regulations.

b. The following tests shall be performed at the point of interconnection:
   i. Power output capability in MW and energy output capacity in MWh.
   ii. Frequency response of ESS.
   iii. Ramping capability as per design.

7.6.6 Documents and tests required for HVDC Transmission System:

a. The transmission licensee shall submit technical details including operating guidelines such as filter bank requirements at various operating loads and monopolar/ or- bipolar configuration, reactive power controller, run-back features, frequency controller, reduced voltage mode of operation, circuit design parameters and power oscillation damping, as applicable.

b. The following tests shall be performed:
   i. Minimum load operation.
   ii. Ramp rate.
   iii. Overload capability, subject to grid condition.
   iv. Black start capability in the case of Voltage source convertor (VSC) HVDC wherever feasible.
   v. Dynamic Reactive Power Support (in the case of VSC based HVDC).

7.6.7 Documents and Tests Required for SVC or STATCOM

a) The transmission licensee shall submit technical particulars including a single line diagram, V/I characteristics, the rating of coupling transformer, the rating of each VSC, MSR and MSC branch, different operating modes, the IEEE standard Model, Power Oscillation Damping (POD) enabled and tuned (if not, then reasons for the same) and the results of an Offline simulation-based study to validate the performance of POD.

b) The following tests shall be performed to validate the full reactive power capability of SVC and STATCOM in both directions, i.e., absorption as well as injection mode:

   (i) POD performance test.

   (ii) dynamic performance testing:

   Provided that the transmission licensee may submit offline simulation studies forthe specified tests, in case the conduct of tests is not feasible before COD, subject to the condition that tests shall be performed within a period of one year from the date of achieving COD.

7.7 Certificate of Successful Trial Run

1. In case any objection is raised by a beneficiary in writing to the SLDC with a copy to all concerned regarding the trial run within two (2) days of completion of such trial run the SLDC shall, within five (5) days of receipt of such objection, in coordination with the concerned entity and the beneficiaries, decide if the trial run was successful or if there is a need for a repeat trial run.

2. After completion of a successful trial run and receipt of documents and test reports as per Regulation 7.6 of these Regulations, SLDC shall issue a certificate to that effect to the concerned generating station, ESS or transmission licensee, as the case

maybe, with a copy to their respective beneficiary(ies), and the STU, within three days.

7.8 Declaration by Generating Company and Transmission Licensee

1. Thermal Generating Station

a) The generating company shall certify that:

The generating station or unit thereof meets the relevant requirements and provisions of the CEA Technical Standards for Construction, CEA Technical Standards for Connectivity, CEA Technical Standards for Communication, Central Electricity Authority (Measures relating to Safety and Electricity Supply) Regulations, 2023, CEA (Flexible operation of thermal power plants) Regulations, 2023 as amended from time to time and these Regulations, as applicable.

(i) The main plant equipment and auxiliary systems including the balance of the plant such as the fuel oil system, coal handling plant, DM plant, pre-treatmentplant, fire-fighting system, ash disposal system and any other site specific system have been commissioned and are capable of full load operation of the units of the generating station on a sustained basis.

(ii) Permanent electric supply system including emergency supplies and all necessary instrumentation, control and protection systems and auto loops for full load operation of the unit has been put into service.

(iii) The certificates required under sub-clause (a) of this Regulation shall be signed by theauthorized signatory not below the rank of CMD or CEO or MD of the generating company and shall be submitted to the SLDC and STU before the declaration of COD.

2. Hydro Generating Station

a) The generating company shall certify that:

i. The generating station or unit thereof meets the requirement and relevant provisions of the CEA Technical Standards for Construction, CEA Technical Standards for Connectivity, CEA Technical Standards for Communication, Central Electricity Authority (Measures relating to Safety and Electricity Supply) Regulations, 2023 as amended from time to time and these

Regulations, as applicable.

ii. The main plant equipment and auxiliary systems including the drainage de-watering system, primary and secondary cooling system, LP and HP air compressor and firefighting system have been commissioned and are capable of full load operation of units on a sustained basis.

iii. Permanent electric supply systems including emergency supplies and all necessary Instrumentations, Control and Protection Systems and auto loops for full load operation of the unit are put into service.

b) The certificates required under sub-clause (a) of this Regulation shall be signed by the authorized signatory not below the rank of CMD or CEO or MD of the generating company and shall be submitted to the concerned SLDC and STU before the declaration of COD.

3. Transmission system

a) The transmission licensee shall submit a certificate signed by the authorized signatory not below the rank of CMD or CEO or MD of the company to SLDC and STU before declaration of COD that the transmission line, sub-station and communication system conform to the CEA Technical Standards for Construction, CEA Technical Standards for Connectivity, CEA Technical Standards for Communication, Central Electricity Authority (Measures relating to Safety and Electricity Supply) Regulations, 2023 as amended from time to time and these Regulations and are capable of operation to their full capacity.

4. Wind, Solar, Storage, and Hybrid Generating Station

a) The generating station based on wind and solar resources, the ESS and the hybrid generating station shall submit a certificate signed by the authorized signatory not below the rank of CMD or CEO or MD to the SLDC and STU before declaration of COD, that the said generating station or the ESS as the case may be, including main plant equipment such as wind turbines or solar inverters or auxiliary systems, as the case may be, has complied with all relevant provisions of CEA Technical Standards for Connectivity, CEA Technical Standards for Communication, Central Electricity Authority (Measures relating to Safety and Electricity Supply) Regulations, 2023 as amended from time to time and these Regulations.

7.9 Declaration of Commercial Operation (DOCO) and Commercial Operation Date (COD)

1. A generating station or unit thereof or a transmission system or an element thereof or ESS may declare commercial operation as follows and inform CEA, SLDC / STU, and its beneficiaries:

(a) Thermal Generating Station or a unit thereof

i. The commercial operation date in the case of a unit of the thermal generation station shall be the date declared by the generating company after a successful trial run at MCR or de-rated capacity as per sub-clause (b) of Regulation 7.4.1 of these Regulations, as the case may be, and submission of a declaration as per sub-clause (1) of Regulation 7.8 of these Regulations.

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

(b) Hydro Generating Station

i. The commercial operation date in the case of a unit of the hydro generating station including a pumped storage hydro generating station shall be the date declared by the generating station after a successful trial run at MCR or de-rated capacity as per sub-clause (b) of Regulation 7.4.1 of these Regulations, as the case may be, and submission of a declaration as per Regulation 7.8 of these Regulations.

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

(c) Transmission System

i. The commercial operation date in the case of an Inter-State Transmission System or an element thereof shall be the date declared by the transmission licensee on which the Transmission System or an element thereof is in regular service at 0000 hours after successful trial operation

for transmitting electricity and communication signals from the sending end to the receiving end as per Regulation 7.5 and submission of a declaration as per sub-clause (3) of Regulation 7.8 of these Regulations:

Provided that the commercial operation date of a transmission element that is a part of the Associated Transmission System (ATS) shall be declared only after a successful trial run of the last element of the said ATS:

Provided further that where only some of the transmission elements of the ATS have achieved a successful trial run and the Connectivity grantee as per applicable Regulations seeks commercial operation of such elements for utilization by such grantee and is agreed upon by the STU, the commercial operation date of such transmission elements of the ATS may be declared by the transmission licensee as per these Regulations:

Provided also that where only some of the transmission element(s) of the ATS have achieved a successful trial run and if the operation of such transmission elements is certified by the SLDC for improving the performance, safety and security of the grid, the commercial operation date of such transmission element(s) of the ATS may be declared by the transmission licensee as per these Regulations:

Provided also that in case a transmission system or an element thereof executed under regulated tariff mechanism is prevented from regular service on or after the scheduled COD for reasons not attributable to the transmission licensee or its supplier or its contractors but is on account of the delay in commissioning of the concerned generating station or in commissioning of the upstream or downstream transmission system of other transmission licensee, the transmission licensee shall approach the Commission through an appropriate Petition along with a certificate from the STU to the effect that the transmission system is complete as per the applicable CEA Standards, for approval of the commercial operation date of such transmission system or an element thereof:

Provided also that in the case of Intra-State Transmission System executed through Tariff Based Competitive Bidding, the transmission licensee may declare deemed COD of the InSTS in accordance with the provisions of the Transmission Service Agreement after obtaining (a) a certificate from

the STU to the effect that the transmission system is complete as per the specifications of the bidding guidelines and applicable CEA Standards, and (b) no load charging certificate from the SLDC, where no load charging is possible.

ii. The COD of a transmission element of the transmission system under Tariff Based Competitive Bidding shall be declared only after the declaration of the COD of all the pre-required transmission elements as per the Transmission Services Agreement:

Provided that in case any transmission element is required in the interest of the power system as certified by the STU, the COD of the said transmission element may be declared prior to the declaration of the COD of its pre-required transmission elements.

(d) Communication System

Date of commercial operation in relation to a communication system or an element thereof shall mean the date declared by the transmission licensee from 0000 hours of which a communication system or element thereof shall be put into service after completion of the site acceptance test including transfer of voice and data to the respective control centres as certified by the SLDC.

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

i. The commercial operation date in the case of units of a renewable generating station shall mean the date declared by the generating station after undergoing a successful trial run as per Regulation 7.4.3 of these Regulations, submission of declaration as per sub-clause (4) of Regulation 7.8 of these Regulations, and subject to fulfilment of other conditions, if any, as per PPA.

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

(f) On declaration of commercial operation date, scheduling of the generating station or unit thereof, shall start from 0000 hours of D+2 (where D is the

date when a generating station intimates the commercial operation of the generating station or unit thereof) or the commercial operation date declared by the generating station or unit thereof, whichever is later.

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8 System Operation Code

8.1 Operating Philosophy

1. All entities, such as SLDC, STU, QCAs, licensees, generating stations, ESS and other grid connected entities shall atall times function in coordination to ensure integrity, stability and resilience of the grid and achieve economy and efficiency in the operation of power system.

2. Operation of the State grid shall be monitored by the SLDC.

3. Detailed Operating Procedures for State grid shall be developed, maintained and updated by the SLDC, consistent with the Detailed Operating Procedures of WRLDC.

4. SLDC, Backup SLDC, Sub-SLDC, LMU or ALDC of DISCOM shall have qualified operating personnel manning the control room round the clock.

5. Every generating station, transmission substation, RE pooling station of 66 kV and above shall have a control room manned by qualified operating personnel round the clock. Alternatively, the same may be operated round the clock from a remotely located control room, subject to the condition that such remote operation does not result in a delay in the execution of any switching instructions and information flow:

   Provided that a transmission licensee owning a transmission line but not owning the connected substation, shall have a coordination centre functioning round the clock, manned by qualified personnel for operational coordination with the concerned load despatch centres and equipped to carry out the operations as directed by concerned load despatch centres.

6. QCA shall have coordination centres functioning round the clock, manned by qualified personnel for operational coordination with the SLDC and generating stations. ESS and Bulk Consumers, which are State entities, shall have coordination centres functioning round the clock and manned by qualified personnel for operational coordination with the concerned load despatch centres.

8.2 Demand Estimation

1. The Distribution Licensee shall formulate a short-term demand forecast considering the previous financial year as base and projecting the demand for the succeeding five years. During this process, the Distribution licensee shall review the

status of loads materializing as per the previous load forecast. Energy sales for each tariff category shall be projected in the forecast period over the corresponding figures relating to the base year by adopting an appropriate statistical method.

2. The projections shall take into account the assumed normal growth for non-specific loads, specific and identified loads of 1 MW and above. The projections shall also take into account the effects of Demand Side Management, if any, Distributed renewable energy systems, and energy conservation. The peak load requirements at each connection point / Interface point shall be estimated, taking into account the distribution losses.

3. The peak load requirement at each Connection Point / Interface Point will essentially ensure that the STU/ Transmission Licensee may determine the corrective/ necessary measures to be taken to maintain the capacity adequacy in the Transmission System up to the Connection Point / Interface Point. This will facilitate the Transmission Licensee to develop the compatible Transmission System.

4. However, if the Distribution Licensee receives power at a number of connection points / Interface points in a compact area, which are interconnected in a ring, then such a Distribution Licensee shall forward the overall long-term demand forecast, as well as at each connection point / Interface point with the variation or tolerance as mutually discussed and agreed upon with the STU/ Transmission Licensee. The aggregate energy and peak load requirements for the Area of Supply shall be estimated taking into account the distribution losses.

5. The Distribution Licensee shall forward the short-term demand forecast for each Connection Point / Interface Point for peak load requirement as well as aggregate energy and peak load demand for the Area of Supply on annual basis to the STU, Transmission Licensee and the Commission along with the following details on the basis of which the forecast is made: (a) Data, (b) Methodology, (c) Assumptions, It shall be the responsibility of all the Distribution Licensees to fully cooperate with STU / SLDC in preparation of demand forecasts for the entire Gujarat State.

6. SLDC shall carry out demand estimation as part of operational planning after duly factoring in the demand estimation done by Distribution licensees and STU as part of resource adequacy planning referred to in Chapter 4 of these Regulations. Demand estimation by SLDC shall be for both active power and reactive power incident on the transmission system based on the details collected from

distribution licensees, grid-connected distributed generation resources, captive power plants and other bulk consumers embedded within the State.

7. SLDC shall develop methodology for daily, weekly, monthly, yearly demand estimation in MW and MWh for operational analysis as well as resource adequacy purposes. SLDC, while estimating demand may utilize state of the art tools, weather data, historical data and any other data. For this purpose, all distribution licensees shall maintain a historical database of demand.

8. The demand estimation by SLDC shall be done on day ahead basis with time block wise granularity for the daily operation and scheduling. In case SLDC observes a major change in demand in real time for the day, it shall immediately submit the revised demand estimate to the WRLDC for demand estimate correction.

9. Each Distribution licenses shall submit node-wise morning peak, evening peak, day shoulder and night off-peak estimated demand in MW and MVA on a monthly and quarterly basis for the nodes at 132 kV and above to SLDC for the preparation of scenarios for computation of TTC and ATC by the WRLDC and NLDC.

10. SLDC shall also estimate peak and off-peak demand (active as well as reactive power) on a weekly and monthly basis for load - generation balance planning as well as for operational planning analysis, which shall be a part of the operational planning data. The demand estimates mentioned above shall have granularity of a time block. The estimate shall cover the load incident on the grid as well as the net load incident taking into account-embedded generation in the form of rooftop solar and other distributed generation.

11. Timeline for submission of demand estimate data by distribution licensees and other entities to SLDC, as applicable shall be as follows:

Table 2: Timeline For Demand Estimation

Demand estimation perspective	Data to be furnished to RLDC by SLDC	Data to be furnished by each Distribution licensee / Bulk consumer to SLDC
Daily demand estimation	10:00 hours of previous day	08:00 hours of previous day
Weekly demand estimation	First working day of previous week	By 12:00 hours of first working day of previous week

Demand estimation perspective	Data to be furnished to RLDC by SLDC	Data to be furnished by each Distribution licensee / Bulk consumer to SLDC
Monthly demand estimation	Fifth day of previous month	3rd day of previous month
Yearly demand estimation	30th Sept of the previous year	15th Sept of previous year

12. All the data shall be collected in accordance with the procedures agreed to between STU / SLDC and each user.

13. The SLDC shall maintain a database of the total demand for the State on an hourly basis.

14. The demand estimation is to be done by all Users / Distribution Licensees on a daily/weekly/monthly /yearly basis for the current year for load - generation balance planning. The SLDC shall carry out system studies for operational planning and to access transfer capabilities for facilitating intra / inter-state open access, based on demand estimation.

15. While the demand estimation for operational purposes is to be done on a daily/weekly/monthly basis initially, mechanisms and facilities at SLDCs shall be created at the earliest to facilitate on-line estimation of demand for daily operational use, for each 15 minutes block.

16. SLDC shall carry out its own demand estimation from the historical data and weather forecast data from time to time and the relevant data provided by the distribution licensees and other concerned persons. SLDC shall furnish the estimate data to the respective RLDC and RPC as per time line specify in Table – 2 above.

17. The SLDC shall take into account the wind and solar energy forecasting to meet the active and reactive power requirement.

18. SLDC and Distribution licenses shall compute forecasting error for intra-day, day-ahead, weekly, monthly and yearly forecasts and analyse the same in order to reduce forecasting error in the future. The computed forecasting errors shall be made available by SLDCs on website.

19. The Distribution Licensees shall provide to SLDC, estimates of loads that may be shed, when required, in discrete blocks with details of arrangements of such load

shedding.

20. All Users / Distribution Licensees shall develop methodologies/mechanisms for daily/ weekly / monthly/ yearly demand estimation (MW, MVAr and MWh) for operational purposes. All Users / Distribution Licensees shall provide relevant data to SLDC from time to time. SLDC shall maintain historical database for demand estimation.

8.3 Generation Estimation

1. The modalities of generation estimation by Intra-State entities shall be as per the procedure and formats for data collection as may be issued by SLDC.

2. SLDC shall forecast generation from wind, solar, ESS and Renewable Energy hybrid generating stations that are intra-State entities, for different time horizons for the purpose of operational planning.

8.4 Adequacy of Resources

1. SLDC shall estimate and ensure the adequacy of resources, identify generation reserves, demand response capacity and generation flexibility requirements with due regard to the resource adequacy framework as specified under Chapter 4 of these Regulations.

2. SLDC shall compile the time block-wise information for the following day in respect of all intra-State entities and shall and furnish the same to the concerned RLDC for validating the adequacy of resources, as specified in the IEGC

8.5 Outage planning

1. Outage planning shall be prepared for the grid elements in a coordinated and optimal manner keeping in view the system operating conditions and grid security:

   a. Annual outage plan shall be prepared as follows:

      i. Annual outage plan of grid elements under State control areas shall be prepared in advance for the financial year by SLDC in consultation with the Users and reviewed before every quarter and before every month.

      ii. Annual outage plan shall be prepared in such a manner as to minimize the overall downtime, particularly where multiple entities are involved in the outage of any grid element(s).

iii. The outage plan of hydro generation plants, REGS and ESS and its associated evacuation network shall be prepared with a view to extracting maximum generation from these sources.

Example: Outage of wind generator may be planned during lean wind season. Outage of solar generator, if required, may be planned during the rainy season. Outage of hydro generator may be planned during the lean water season.

iv. Protection relay related outages, auto–re-closure outages and SPS testing outages shall be planned on a monthly basis with the prior permission of the WRPC if required.

b. Outage Planning Process shall be as follows:

i. SLDC shall prepare and finalize the annual outage plan for the next financial year in respect of grid elements under control area.

ii. SLDC shall prepare Load Generation Balance Report (LGBR) for the State based on data submitted by the State entity generating stations, intra-State transmission licensees and other entities directly connected to InSTS in such format as may be stipulated by the SLDC and shall prepare annual outage plan for generating units and transmission elements in the control area after carrying out necessary system studies in order to ensure system security and resource adequacy.

iii. SLDC shall finalize the outage plans in consultation with the WRLDC. The final outage plan and the final LGBR shall be intimated to WRLDC, Users, STU, and the generating stations connected to the InSTS.

iv. The timeline for Outage Planning Process shall be as follows:

Table 3: Timeline For Outage Planning Process

Activity	Agency	Cut-off date
Submission of proposed outage plan for the next financial year to SLDC with the earliest start date and latest finishing date	STUs, transmission licensees, generating stations and other entities directly connected to Intra-State Network	15th October
Submission of complied data of proposed outages for the next	SLDC	31st October

Activity	Agency	Cut-off date
financial year to WRPC		
Submission of LGBR of the control area to RPC for both peak and off-peak scenarios	SLDC	31st October

v. The annual outage plan shall be reviewed by the SLDC on quarterly and monthly basis in consultation with all the concerned agencies mentioned above, regarding any changes necessitated during the period, and the revised outage plan shall be intimated to all Users. The Users' requests for additional outages, if any, shall be considered by the SLDC and accommodated to the extent possible. Such changes shall be informed by the SLDC promptly to all concerned. The Distribution Licensees shall also inform the consumers through publications in local newspapers whenever interruptions to power supply would affect them.

vi. All Users, STU, and licensees shall follow the annual outage plan. If any deviation is required, the same shall be allowed only with the prior permission of the concerned RPC, which shall consult the SLDC and concerned RLDC.

vii. Each user and STU shall obtain the final approval from SLDC prior to availing an outage.

viii. In case of emergency in the system, viz., loss of generation, breakdown of transmission line affecting the system, grid disturbances or system isolation, SLDC may conduct studies again before clearance of the planned outage.

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

x. SLDC may conduct studies again before giving clearance of the planned outage.

xi. To facilitate coordinated planned outages of grid elements, a common outage planning procedure shall be formulated by SLDC in line with WRPC outage procedure.

xii. The SLDC shall submit quarterly report indicating deviation in outages from

the plan along with reasons to State Operation Coordination Committee (SOCC). These reports shall also be put up on the SLDC website.

8.6 Demand Control and Demand disconnection:

1. The demand and load shall be managed for ensuring grid security.

2. SLDC, in coordination with STU and Distribution Licensee (s), shall develop AutomaticDemand Management scheme with emergency controls at SLDC.

3. Whenever the power system is in an alert state or emergency state as assessed bySLDC or advised by RLDC:

   a. The respective distribution licensee under State control area shall abide by the directions of SLDC to secure the system, and extreme measures like load shedding may be carried out as a last resort.

   b. SLDC or RLDC through SLDC may direct distribution licensees or bulk consumers directly connected to STU, to restrict drawal from the grid or curtail load to ensure the stability of the grid:

      Provided that load shedding shall be resorted to after the demand response option has been exhausted.

   c. The load disconnected, if any, shall be restored as soon as possible on clearance from SLDC, in coordination with RLDC if required, after the system has been normalized.

4. Planned manual disconnection shall be implemented by the respective Distribution Licensee upon instruction of SLDC when there is a shortfall in generation, or constraints in Transmission System, or reduction of imports through external connection, etc., requiring demand control over prolonged period to control the over drawal of power from ISTS network.

5. Emergency manual disconnection to deal with unacceptable voltage and frequency levels, etc., shall be implemented by the SLDC only when loss of generation, mismatch of generation with the demand or constraints in the Transmission System, as well as in case of over drawal from the grid in excess of respective schedule.

6. These control measures shall not be withdrawn till the system voltage or

frequency, as the case may be, improves and when the SLDC issues such instructions after review of the situation.

7. Distribution Licensee and bulk consumer shall initiate action to restrict the drawal of its control area, from the grid, within the net drawal schedule as per system requirement.

8. The Distribution Licensee and Bulk Consumer shall ensure that there is no over drawal from the grid in its control area when frequency is 49.90 Hz or below or frequency range as per IEGC as amended from time to time.

9. Each User / STU in coordination with SLDC shall formulate contingency procedures and make arrangements that will enable demand disconnection to take place, as instructed by the RLDC/SLDC, under normal and/or contingent conditions. These contingency procedures and arrangements shall regularly be / updated by the User/STU and monitored by SLDC. SLDC may direct any user/STU to modify the above procedures / arrangement, if required, in the interest of grid security and the concerned user/STU shall abide by these directions.

10. The SLDC, through the respective Distribution Licensees, shall also formulate and implement state-of-the-art demand management schemes for automatic demand management. However, it shall be implemented in accordance with prevailing IEGC provisions to reduce over drawal in order to comply with sub-clause (8) and (9) of above. A report detailing the scheme and periodic reports on progress of implementation of the schemes shall be sent to the Commission by SLDC.

11. In order to maintain the frequency within the stipulated band and maintaining the network security, the interruptible loads shall be arranged in four groups of loads, for scheduled power cuts / load shedding, loads for unscheduled load shedding, loads to be shed through under frequency relays/ df/dt relays and loads to be shed under any system protection scheme identified by SLDC or at the RPC level. These loads shall be grouped in such a manner, that there is no overlapping between different groups of loads. In case of certain contingencies and/or threat to system security, the RLDC may direct any SLDC/ Distribution Licensee or bulk consumer connected to the Intra-State network to decrease drawal of its control area by a certain quantum. Such directions shall immediately be acted upon. SLDC shall send compliance report immediately after compliance of these directions to RLDC.

12. To comply with the direction of RLDC, SLDC may direct any Distribution Licensee / bulk consumer connected to the Intra-State network to curtail drawal from the grid. SLDC shall monitor the action taken by the concerned entity and ensure the reduction of drawal from the grid as directed by RLDC.

13. SLDCs shall devise standard, instantaneous, message formats in order to give directions in case of contingencies and /or threat to the system security to reduce over drawal by the distribution licensee/bulk consumers under different overdrawal conditions depending upon the severity of the over drawal. The concerned distribution licensee/bulk consumer shall ensure immediate compliance with these directions of SLDC and send a compliance report to the SLDC. These control measures shall not be withdrawn till further instruction of SLDC after review of the situation.

14. All Users, / Distribution Licensees or bulk consumer shall comply with the directions of RLDC/SLDC and carry out requisite load shedding or backing down of generation in case of congestion in the Transmission System to ensure safety and reliability of the system. The procedure for application of measures to relieve congestion in real time as well as provisions of withdrawal of congestion shall be in accordance with SLDC detailed procedure as approved by the Commission.

8.7 System Security

1. All Users shall operate their respective power systems in an integrated manner at alltimes in coordination with the SLDC / Sub - SLDC.

2. Isolation, taking out of service and switching off an element of the grid:

   a. No element(s) of the grid shall be isolated from the grid, except (i) during an emergency as per the Detailed Operating Procedure(s) of SLDC, as the case may be, where such isolation would prevent a total grid collapse or would enable early restoration of power supply; (ii) for the safety of human life; (iii) when serious damage to a critical equipment is imminent and such isolation would prevent it; and (iv) when such isolation is specifically instructed by RLDC or SLDC, as the case may be. Any such isolation shall be reported to the respective RLDC or SLDC within the next 15 minutes.

   b. The transmission lines of 132 kV and above and 66 kV lines meant for connecting CPP with grid and the interconnecting power transformers should not be opened without instructions or prior clearance from the SLDC unless under

emergencies when prior clearance is not possible. SLDC shall also be informed and get the clearance, while bringing back these lines into service.

c. Any tripping of the transmission lines of 132 kV and above or power transformers of 132 kV class (i.e., 132/66 kV, etc.) and above and 50 MVA and above whether actuated by protective relays or manually, shall be promptly reported to the SLDC / Sub-SLDC by the Engineer in charge of the substation at the earliest along with the reasons for such tripping and the time required for restoration but not later than 30 minutes from the occurrence of event. The report shall accompany with all the relevant information/data including the outputs of the disturbance recorder, sequential event recorder, etc., required for the purpose of analysis. SLDC shall give concurrence based on grid conditions and confirmation of site readiness. SLDC and the Users shall ensure restoration of such elements within the estimated time of restoration as intimated.

d. SLDC, in consultation with WRPCs, WRLDC, and Users, shall prepare a list of important elements in the State grid including those in the regional grids that are critical for regional/State grid operation and shall make the said list available to all concerned.

e. An important element of the grid as listed at sub-clause (2) of this Regulation can be taken out of service only after prior clearance of the SLDC/WRLDC, except in emergencies as per the Detailed Operating Procedure(s) of WRLDC or SLDC, as the case may be.

f. The isolated, taken out or switched off elements shall be restored as soon as the system conditions permit. The concerned sub-SLDC/SLDC, in coordination with SLDC/RLDC, in accordance with the system restoration procedures of RLDC/ SLDC shall supervise the restoration process.

3. The respective Users in accordance with the provisions of the CEA Grid Standards shall carry out maintenance of grid elements. Outage of an element that is causing or likely to cause danger to the grid or sub-optimal operation of the grid shall be monitored by SLDC. SLDC shall report such outages to WRPC, and WRPC shall issue suitable instructions to restore such elements in a specified time period.

4. No important element of the State grid shall be deliberately opened or removed from service at any time, except when specifically instructed by SLDC or with specific and prior clearance of SLDC. The list of such important grid elements on which the above stipulations apply shall be prepared by the SLDC, in consultation

with the concerned Users and STU, and be available on the website of SLDC.

5. In case of opening/removal of any important element of the grid under an emergency, the same shall be communicated to SLDC at the earliest possible time after the event. SLDC shall inform the opening/removal of the important elements of the State grid to RLDC.

6. Any prolonged outage of power system elements of any user/STU, which is causing or likely to cause danger to the State grid or sub-optimal operation of the State grid, shall regularly be monitored by SLDC. SLDC shall report such outages to SOCC. The SOCC shall finalize the action plan and give instructions to restore such elements in a specified time period. In case of non-compliance of the instruction of SLDC to restore the element in a specified time period, the matter shall be referred to the Commission for initiating actions against such non-compliance.

7. Except in an emergency, or when it becomes necessary to prevent imminent damage to critical equipment, no user shall suddenly increase of decrease its generating unit output by more than 50 (fifty) MW without prior permission of the SLDC.

8. Except in an emergency, or when it becomes necessary to prevent imminent damage to critical equipment, no user shall cause a sudden variation in its load by more than 50 (fifty) MW without the prior permission of the SLDC.

9. All generating units shall have their automatic voltage regulators (AVRs), Power System Stabilizers (PSSs), voltage (reactive power) controllers (Power Plant Controller) and any other requirements in operation, as per the CEA Technical Standards for Connectivity. If a generating unit with a capacity higher than 100 (hundred) MW is required to be operated without its AVR or voltage controller in service, the generating station shall immediately inform the concerned SLDC of the reasons thereof and the likely duration of such operation and obtain its permission.

10. The tuning of AVR, PSS, Voltage Controllers (PPC) including for low and high voltageride through capability of wind generators, solar generators, wind-solar hybrid generators with or without Energy Storage System (ESS) and standalone ESS or any other requirement as per CEA Technical Standards for Connectivity shall be carried out by the respective generating station:

a. at least once every five (5) years;

b. based on operational feedback provided by the WRLDC/SLDC after analysis of a grid event or disturbance; and

c. in case of major network changes or fault level changes near the generating station as reported by WRLDC/SLDC, as the case may be.

d. in case of a major change in the excitation system of the generating station.

11. Power System Stabilizers (PSSs), AVRs of generating units and reactive power controllers shall be properly tuned by the generating station as per the plan and the procedure prepared by the WRPC/SLDC. In case the tuning is not complied with as per the plan and procedure, the SLDC shall issue notice to the defaulting generating station to complete the tuning within a specified time, failing which the SLDC may approach the Commission.

12. Provisions of protection and relay settings shall be coordinated periodically throughout the state grid, as per the plan finalized by the SPC in accordance with these Regulations.

13. WRPC shall prepare the islanding schemes in accordance with the CEA Grid Standards for identified generating stations, cities and locations and ensure their implementation. The islanding schemes shall be reviewed and augmented depending on the assessment of critical loads at least once a year or earlier, if required.

14. Mock drill of the islanding schemes shall be carried out annually by the WRLDC in coordination with the SLDCs and other Users involved in the islanding scheme. In case mock drill with field-testing is not possible to be carried out for a particular scheme, simulation testing shall be carried out by the SLDC/WRLDC.

15. All distribution licensees, STUs and bulk consumers shall provide automatic under- frequency relays (UFR) and df/dt relays for load shedding in their respective systems to arrest frequency decline that could result in grid failure as per the plan given by the WRPC from time to time.

The default UFR settings shall be as specified in Table-4 below:

Table 4: Default UFR Settings

Sr. No.	Stage of UFR Operation	Frequency (Hz)
1	Stage-1	49.40
2	Stage-2	49.20
3	Stage-3	49.00
4	Stage-4	48.80
Note 1: STU shall plan UFR settings and df/dt load shedding schemes depending on their local load generation balance in coordination with and approval of the *WRPC.*		
Note 2: Pumped storage hydro plants operating in pumping mode or ESS operating in charging mode shall be automatically disconnected before the first stage of UFR.		

The load shedding for each stage of UFR operation, in percentage of demand or MW shall be as finalized by the WRPC.

16. The following shall be factored in while designing and implementing the UFR and df/dt relay schemes:

    a. The under-frequency and df/dt load shedding relays are always functional.

    b. Demand disconnection shall not be set with any time delay in addition to the operating time of the relays and circuit breakers.

    c. There shall be a uniform spatial spread of feeders selected for UFR and df/dt disconnection.

    d. SLDC shall ensure that telemetered data of feeders (MW power flow in real time and circuit breaker status) on which UFR and df/dt relays are installed is available at its control centre. SLDC shall monitor the combined load in MW of these feeders at all times. SLDC shall share the above data with the WRLDC in real time and submit a monthly exception report to the WRPC. WRLDC shall inform SLDCs as well as the WRPC on a quarterly basis, durations during the quarter when the combined load in MW of these feeders was below the level considered while designing the UFR scheme by the WRPC. SLDC/STU shall take corrective measures within a reasonable period and inform the WRLDC and WRPC, failing which suitable action may be initiated by the WRPC.

e. WRPC shall undertake a monthly review of the UFR and df/dt scheme and also carry out random inspection of the under-frequency relays. WRPC shall publish such a monthly review along with an exception report on its website.

f. SLDC shall report the actual operation of UFR and df/dt schemes, load relief to the WRLDCs and WRPC, and publish the monthly report on its website.

17. SLDC, STU or Users may identify the requirement of System Protection Schemes (SPS) (including inter-tripping and run-back) in the power system to operate the transmission system within operating limits and to protect against situations such as voltage collapse, cascade tripping and tripping of important corridors/flow-gates.

18. SPS shall be installed and commissioned by the concerned Users. SPS shall always be kept in service. If any SPS at the intra-State level is to be taken out of service, the permission of SLDC shall be required.

19. All Users, SLDC and STU shall take all possible measures to ensure that the steady-state grid voltage always remains within the following operating range as per the CEA Grid Standards:

Table 5: VOLTAGE RANGE

Voltage (kV rms)		
Nominal	**Maximum**	**Minimum**
765	800	728
400	420	380
230*	245*	207*
220	245	198
132	145	122
110	121	99
66	72	60
33	36	30

**As per CEA Manual on Transmission Planning Criteria, 2023*

20. SLDC shall take appropriate measures to control the voltage as per their operating procedures.

21. All Users and STU shall provide adequate voltage control measures through voltage relay as finalized by SLDC / WRPC, to prevent voltage collapse and shall

ensure its effective application to prevent voltage collapse/ cascade tripping.

22. The concerned Users shall implement defence mechanisms as finalized by the WRPC to prevent voltage collapse and cascade tripping.

23. SLDC shall make all efforts to evacuate the available solar, wind and other RE power and treat as a must-run station:

    Provided that the SLDC may instruct the solar /wind and other RE generator to back down generation on consideration of grid security or safety of any equipment or personnel is endangered, and solar/ wind and other RE generator shall comply with the same:

    Provided further that the SLDC/WRLDC may direct pooling station of wind / solar and other RE generator to curtail its VAr drawal/injection in case the security of grid or safety of any equipment or personnel is endangered.

24. During the wind generator start-up, the wind generator shall ensure that the reactive power drawal (in-rush currents in case of induction generators) shall not affect the grid performance. For these, Data Acquisition System facility shall be provided for transfer of information to concerned Sub-SLDC and SLDC.

25. All defence mechanisms shall always be in operation and the concerned user shall immediately intimate any exception to the SLDC along with the reasons and the likely duration of such exception. The concerned user shall also obtain permission from the SLDC.

8.8 Frequency Control

1. The National Reference Frequency shall be 50.000 Hz and the allowable band of frequency shall be as per the IEGC, which is presently 49.900-50.050 Hz. The frequency shall be measured with aresolution of +/-0.001 Hz by SLDC and such frequency data measured every second shall be archived by SLDC.

2. The SLDC shall endeavour that the grid frequency remains close to 50.000 Hz and in case frequency goes outside the allowable band, ensure that the frequency is restored within the allowable band of 49.900-50.050 Hz at the earliest as per direction of RLDC and NLDC.

3. All users shall adhere to their schedule of injection or drawal, as the case may be, andtake such action as required under these Regulations and as directed by NLDC

or WRLDCs or SLDC so that the grid frequency is maintained and remains within the allowable band.

8.9 Reserves

1. There shall be reserves as under:

a. Primary, Secondary and Tertiary reserves:

i. Primary, Secondary and Tertiary reserves shall be deployed for the purpose of frequency control, reducing area control error and relieving congestion.

ii. The response under Primary reserve shall be provided as per these Regulations.

iii. Secondary reserves including automatic generation control and demand response shall be deployed by the control area as per the CERC Ancillary Service Regulations and / or Ancillary Service Regulation of the Commission as may be notified from time to time or any other Regulation notified by the Commission for this purpose, as the case may be.

iv. Tertiary reserves shall be deployed by the control area as per these Regulations or the CERC Ancillary Services Regulations and / or Ancillary Service Regulation of the Commission as may be notified from time to time or any other Regulation notified by the Commission for this purpose, as the case may be.

b. Black Start reserves:

Generating stations having black start capability, ESS and HVDC Station based on VSC shall be identified by SLDC at the State level in consultation with RLDC, to act as black start reserves.

c. Voltage Control reserves:

i. Voltage Control reserves shall be deployed for controlling the voltage at a bus or sub-system through reactive power injection or drawal.

ii. The reserves shall be operated as Ancillary Services, namely (a) Primary Reserve Ancillary Service (PRAS); (b) Secondary Reserve Ancillary Service (SRAS); (c) Tertiary Reserve Ancillary Service (TRAS); (d) Black Start Ancillary Services; and (e) Voltage Control Ancillary Services.

iii. The mechanism of procurement and deployment of PRAS shall be as specified in these Regulations or in the Ancillary Services Regulations, as the case may be.

iv. The mechanism of procurement, deployment and payment of SRAS and TRAS shall be as specified in the CERC Ancillary Services Regulations and / or Ancillary Service Regulation of the Commission as may be notified from time to time or any other Regulation notified by the Commission for this purpose, as the case may be.

v. The SLDC shall verify the primary response of the generating units during grid events. The concerned generating station shall furnish the requisite data to the SLDC within two days of notification of reportable event by the NLDC.

8.10 Control Hierarchy

The following Control Hierarchy shall be in force till such time the Commission notifies the Ancillary Services Regulations for the State of Gujarat.

1. Inertia:

The power system shall be operated at all times with a minimum inertia as stipulated by NLDC so that the minimum nadir frequency post reference contingency stays above the threshold set for under frequency load shedding (UFLS). To maintain the minimum inertia, the SLDC may, if required, bring quick start synchronous generation on bar and reschedule generation including curtailment of wind, solar and wind-solar hybrid generation, in coordination with the WRLDC. The compensation for such quick start synchronous generation shall be as per the procedure prepared by SLDC and approved by the Commission.

2. Primary Control:

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

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

c. The minimum quantum of PRAS required for reference contingency shall be declared by SLDC/WRLDCNLDC at the start of each financial year.

d. The generating stations and units thereof shall have electronically controlled governing systems or frequency controllers in accordance with the CEA Technical Standards for Connectivity and are mandated to provide PRAS. The generating stations and units thereof with governors shall be under Free Governor Mode of Operation.

e. SLDC/WRLDCNLDC may also identify other resources such as ESS and demand resource to provide PRAS for which PRAS Providers shall be compensated in accordance with the applicable Ancillary Services Regulations.

f. The minimum target frequency response characteristics (FRC) shall be estimated, and based on such target FRC, the frequency response obligation of each control area shall be assessed by NLDC/RLDC, giving due consideration to generation and load within each control area and details as given in Table 6 under sub-clause(h) of this Regulation.

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

h. The primary response requirement shall be as mentioned in Table 6 as under:

Table 6: Primary Response Of Various Types Of Generating Units

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

Fuel/ Source	Minimum unit size / Capacity	Up to
(commissioned after the date as specified in the CEA Technical Standards for Connectivity)	station more than 10 MW and connected at 33 kV and above	As per CEA Technical Standards for Connectivity

Provided that:

i. WS Sellers commissioned after the date as specified in CEA Technical Standards for Connectivity shall have the option to provide primary response individually through ESS or through a common ESS installed at its pooling station.

ii. Nuclear generating stations and hydro generating stations (with pondage up to 3 hours or Run of the river projects) shall be exempt from mandatory primary response. They may provide the primary response to the extent possible, considering the safety and security of machines and humans.

iii. All generating stations mentioned in Table-6 above shall have the capability of instantaneously picking up to a minimum of 105% of their operating level and up to 105% or 110% of their MCR, as the case may be, when the frequency falls suddenly and thus, providing primary response whenever conditions arise. Any generating station not complying with the above requirements shall be kept in operation (synchronized with the regional/State grid) only after obtaining the permission of the WRLDC/SLDC.

iv. ll generating stations, including the WS seller mentioned in Table-6 above shall have the capability of reducing output at least by 5% or 10%, as applicable, of their operating level and up to 5% or 10% of their MCR, as applicable, limited to the minimum turndown level when the frequency rises above the reference frequency and thus, providing primary response, whenever conditions arise. Any generating station not complying with the above requirements shall be kept in operation (synchronized with the regional/State grid) only after obtaining permission from the WRLDC/SLDC.

v. The normal governor action shall not be suppressed in any manner through load limiter, Automatic Turbine Run-up System (ATRS), turbine supervisory control or coordinated control system, and no time delays shall be deliberately introduced. In the case of a renewable energy generating unit, a reactive power limiter or power factor controller or voltage limiter shall not suppress the primary frequency responsewithin its capabilities. The inherent dead band of a generating unit or frequency controller shall not exceed +/- 0.03 Hz.

vi. The governor shall be set with respect to a reference frequency of 50.000 Hz and response outside the dead band shall be with respect to a total change in frequency.

vii. The thermal and hydro generating units shall not resort to Valve Wide Open (VWO) operation to make available margin for providing governor action.

viii. The PRAS shall start immediately when the frequency deviates beyond the dead band as specified in sub-clause (v) of this Regulation and shall be capable of providing its full PRAS capacity obligation within 45 seconds and sustaining at least for the next five (5) minutes.

ix. SLDC shall assess its frequency response characteristics and share with the WRLDC along with high-resolution data of at least 1 (one) second for regional entity generating stations and energy storage systems and 10 (ten) seconds for the State control area.

x. The SLDC shall calculate actual frequency response characteristics of all Intra-State entities within State. The performance of each Intra-State entity in providingfrequency response characteristics shall be calculated for each reportable event as per **Annexure-3.**

xi. SLDC shall grade the median Frequency Response Performance (FRP) annually, considering at least 10 reportable events. In case the median Frequency Response Performance is less than 0.75 as calculated as per **Annexure-3**, SLDC after analysing the FRP, shall direct the concerned entities to take corrective action. All such cases shall be reported to the SOCC for its review.

3. Secondary Control:

a. Secondary control is a centralized automatic function to regulate the generation or load in a control area to restore the frequency within the allowable band or replenish deployed primary reserves.

b. Secondary Control shall be provided by a generating station or an entity having energy storage resource or an entity capable of providing demand response, on a standalone or aggregated basis, connected to an inter-State transmission system or an intra-State transmission system, as a Secondary Reserve Ancillary Service (SRAS) Provider, as specified in the Ancillary Services Regulations of CERC and / or the Commission, as applicable.

c. Secondary control signals shall be automatically generated from SLDC and shall be transmitted to SRAS Providers for desired automated response when the Area Control Error (ACE) for Intra-State entities goes beyond the minimum threshold limit as decided and reviewed by SLDC from time to time based on the review of the performance of SRAS:

Provided that as and when the bi-directional communication system of SRAS providers with SLDC is fully established, secondary control signals shall be automatically generated from the SLDC.

d. ACE of State control area, shall be auto calculated at the control centre of SLDC, based on telemetered values, and external inputs, namely, the Frequency Bias Coefficient and Offset referred to in sub-clauses (e) and (f) respectively of this Regulation as per the following formula:

$$ACE = (I_a - I_s) - 10 * B_f * (F_a - F_s) + Offset$$

Where,

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

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

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

F_a = Actual system frequency in Hz

F_s = Schedule system frequency in Hz

Offset = Provision for compensating measurement error

e. Frequency Bias Coefficient (Bf) shall be assessed and declared by SLDC for the State. Frequency Bias Coefficient shall normally be based on the median Frequency Response Characteristics (FRC) observed during the previous financial year for State control area and refined from time to time.

f. Offset shall be used to account for measurement errors and shall be decided by SLDC.

g. Secondary control may be operated under tie-line bias control, flat frequency control or flat tie-line control mode depending on grid requirements:

   Provided that Secondary control may be suspended due to system maintenance or grid security or for any other reasons to be recorded in writing:

   Provided further that SLDC shall lay down in the detailed operating procedure after stakeholder consultation, the conditions during which a particular mode shall be chosen and shall document the reasons for operating in a particular mode:

   Provided also that the coordinated operation of AGC by the nested control areas shall be adopted based on mutually agreed protocols.

h. Schedule system frequency (Fs) shall be a reference frequency of 50 Hz unless otherwise specified by NLDC under certain conditions to be recorded in writing.

i. SLDC shall compute the ACE of State control area in real time based on telemetered data. ACE data shall be archived at an interval of 10 seconds or less. SLDC shall share the data with the WRLDC and NLDC.

j. The SRAS Providers shall start responding to SRAS signals within thirty (30) seconds of receipt of the signal and shall be capable of providing the entire SRAS capacity obligation within fifteen (15) minutes and sustaining it at least for the next thirty (30) minutes. The secondary reserves shall be gradually replaced by tertiary reserves within 30 minutes.

k. With due regard to the requirement of planning reserve margin and resource adequacy referred to in these Regulations and based on the following

methodologies, the secondary reserve capacity requirements shall be estimated by SLDC for the State control areas:

The positive and negative secondary reserve capacity requirements for control area for a calendar year shall be equal to the 99 percentile of positive and negative ACE respectively of control area during the previous financial year.

SLDC shall prepare the detailed procedure for assessment of Secondary and Tertiary Reserves and obtain the Commission's approval for the same.

OR

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

OR

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

l. Unless otherwise specified by the Commission, the methodology specified in sub-clause (k) of this Regulation shall be adopted by the SLDC to estimate the secondary reserve capacity requirement in their respective control areas.

m. The reserve capacity requirement as per the methodology mentioned in sub-clauses (k) and (l) of this Regulation shall be estimated by SLDC by 15th January every year for the next financial year and submitted to NLDC.

n. Secondary reserve capacity requirement for the State control area shall be estimated by SLDC based on reference contingency and other factors such as forecast errors.

o. SLDC shall re-assess the quantum of requirement of secondary reserves required at the State control area three days before the day of scheduling and communicate the same to the Intra-State entities.

p. SLDC shall ensure the availability of the quantum of secondary reserve at the State control area with due regard to the secondary reserves estimated and

allocated for the State as published by NLDC and inform the same to the concerned entities two days before the day of scheduling.

q. SLDC shall re-assess the quantum of the requirement for secondary reserves at the State control area and the need to replenish primary reserves two days before the day of scheduling inter-alia to identify reserves to be brought on bar under SCUC and as per the provision of these Regulations.

r. SLDC shall further re-assess the quantum of the requirement for secondary reserve at the State level on day ahead basis and also on a real time basis.

s. If concerned entity falls short of maintaining Secondary Reserve capacity as allocated to it, SLDC shall procure such Secondary Reserve capacity on behalf of the concerned entity under advance intimation and allocate the cost of procurement of such capacity to that entity based on the methodology as per the detailed procedure to be issued by the SLDC after approval of the Commission.

t. SLDC shall indicate the shortfall in secondary reserves, if any, and announce emergency alerts for such periods.

u. Secondary reserves shall be procured by the SLDC from a generating station or an entity having energy storage resources or an entity capable of providing demand response, on a standalone or aggregated basis, connected to the intra-State transmission system in accordance with these Regulations.

v. All thermal generating stations having a capacity of more than 200 MW and hydro generating stations having a capacity of more than 25 MW shall make arrangements to enable automatic operation of the plant from the appropriate load despatch centre by integrating the controls and telemetering features of their system into the automatic generation control in accordance with the CEA TechnicalStandards for Construction and the CEA Technical Standards for Connectivity. The communication system shall be established in accordance with the CEA Communication Regulations as amended from time to time.

w. All renewable energy generating stations and ESS shall be equipped with the facility to control active power injection in accordance with the CEA Connectivity Standards and the communication system shall be established

in accordance with the CEA Technical Standards for Communication.

x. SRAS shall have a bi-directional communication system along with metering and SCADA telemetry in place as per the requirements stipulated in the Detailed Procedure to be issued by SLDC with the approval of the Commission.

4. Tertiary Control:

a. Tertiary reserve requirement for the State control area, shall be estimated by SLDC with due regard inter-alia to the requirement of planning reserve margin and resource adequacy as referred to in these Regulations and its amendments, so as to take care of contingencies and to cater to the need for replacing secondary reserves estimated as per Regulation 8.10 (3)(k) of these Regulations by 25th January every year, which will be implemented for the next financial year from 1st April onwards by the State control areas.

b. SLDC shall allocate such tertiary reserve capacity, to be maintained at State control areas, based on the estimated reserves as per IEGC and publish the information on its website by 25th January every year.

c. NLDC through RLDC will re-assess the quantum of requirements for tertiary reserves required at the State control area three (3) days before the day of scheduling and communicate the same to the SLDC. Same shall be apportioned to their control area of Distribution Licensee by SLDC.

d. Distribution licensee/s shall ensure the availability of the quantum of tertiary reserve at their control area with due regard to the tertiary reserves estimated and allocated for the State as published by NLDC in terms of sub-clauses (b) and (c) of this Regulation, and inform the same to the SLDC two (2) days before the day of scheduling.

e. SLDC shall ensure availability of the quantum of tertiary reserve atthe State control area on day ahead basis with due regard to the tertiary reserves estimated and allocated to the State by NLDC and inform the concerned entities.

f. SLDC shall re-assess the quantum of requirements for tertiary reserve at the State level with due regard to the estimation inter-alia of tertiary reserves maintained at State control area and the need to replace secondary reserves,

three days before the day of scheduling inter alia to identify reserves to be brought on bar under SCUC and as per the provisions of these Regulations.

g. SLDC shall further re-assess the quantum of the requirement for tertiary reserve on day ahead basis and also on a real time basis.

h. If entity falls short of maintaining tertiary reserve capacity as allocated to it, SLDC shall procure such tertiary reserve capacity on behalf of the said entity under advance intimation and allocate the cost of procurement of such capacity to that entity based on the methodology as per the detailed procedure to be issued by the SLDC after approval of the Commission.

i. Tertiary reserves shall be procured by the SLDC from a generating station or an entity having energy storage resourced or an entity capable of providing demand response, on a standalone or aggregated basis, connected to an intra-State transmission system in accordance with these Regulations.

j. Tertiary reserves to be provided by the TRAS provider shall be capable of providing TRAS within fifteen (15) minutes of despatch instructions from SLDC, and shall be capable of sustaining the service for at least the next 60 minutes. TRAS shall be activated and deployed on account of the following events:

    i. To replenish the secondary reserve, in case the secondary reserve has beendeployed continuously in one direction for fifteen (15) minutes for more than 100 MW or such other volume limit as may be specified by the Commission;

    ii. Generation unit or transmission line outages;

    iii. Any such other event affecting the grid security.

k. The quantum of reserves procured by SLDC shall becommunicated to the concerned entities.

l. The modalities for information exchange and timelines in respect of tertiary reserves shall be as per detailed procedure prepared by SLDC. The control area wise performance of SRAS, TRAS providers shall be evaluated in accordance with the Detailed Procedure prepared by SLDC.

8.11 Operation Planning

8.11.1 Time Horizon

(a) Operational planning shall be carried out in advance by SLDC with Monthly and Yearly time horizons in co-ordination with Distribution Licensees, STU and other entities, as applicable.

(b) Operational planning shall be carried out in advance by SLDC on Intra-day, Day Ahead, Weekly time horizons.

(c) SLDC shall issue procedures and formats for data collection to carry out:

(i) Operational planning analysis

(ii) Real-time monitoring,

(iii) Real-time assessments.

(d) SLDC may also issue procedures and formats for data collection for the above purposes and review the same from time to time.

8.11.2 Adequacy of Resources

(a) Distribution Licensees and other entities in the State in coordination with SLDC shall estimate and ensure the adequacy of resources, identify generation reserves, demand response capacity and generation flexibility requirements with due regard to the resource adequacy framework as specified under these Regulations.

(b) SLDC shall prepare time block-wise information for the following day in respect of all intra-State entities to validate the adequacy of resources with due regard to the following:

i. Aggregated Demand forecast by State entities;

ii. Renewable energy generation forecast;

iii. Injection schedule for intra-State entity generating station;

iv. Requisition from regional entity generating stations;

v. Secondary and planned procurement through Tertiary reserve

requirement;

vi. Planned procurement of power through other bilateral or collective transactions, if any.

(c) The required contingency reserve shall be decided by the SLDC on the basis of historical trends in the reduction of availability of the generating companies, imports through inter- State tie lines and increases in demand forecast during real time operation.

(d) Whenever the contingency reserve is to be held by a thermal power station, the SLDC shall include the same in the Indicative running notification and/or subsequent dispatch. Instructions by which the generating company is notified of and/or instructed, that the generating unit shall be operated in the contingency reserve mode.

8.11.3 Operational Planning Study

Based on the operational planning analysis data, operational planning study shall be carried out by various agencies for different time horizons as under:

Table 7: Time Horizon for Operational Planning Study

Time horizon of operational planning study	Agency	Means for carrying out study
Real time and Intra-day	SLDC	For various operating conditions using online/offline SCADA/EMS system
Day-ahead	SLDC	For various operating conditions using offline tools
Weekly	SLDC	For various operating conditions using offline tools
Monthly/Yearly	SLDC and STU	For various operating conditions using offline tools
Note: The Critical transmission element outages shall not be processed without conducting the operational studies.		

1. SLDC shall utilize network estimation tool integrated in their EMS and SCADA systems for the real time operational planning study. All Users shall make available at all times real time error free operational data for the successful execution of network analysis using EMS/SCADA. Failure to make available such data shall be immediately reported to the SLDC along with a firm timeline for restoration. The performance of online network estimation tools shall be reviewed in SOCC. Any telemetry related issues impacting the online network estimation tool shall be monitored by SOCC for their early resolution.

2. SLDC shall perform day-ahead, weekly, monthly and yearly operational studies for the State for:

    a. Assessment and declaration of total transfer capability (TTC) and available transfer capability (ATC) for the import or export of electricity by the State.

    b. TTC and ATC shall be revised from time to time based on the commissioning of new elements and other grid conditions and shall be published on SLDC website with all the assumptions and limiting constraints:
        i. planned outage assessment;
        ii. special scenario assessment;
        iii. system protection scheme assessment;
        iv. natural disaster assessment; and
        v. any other study relevant in operational scenario.

    c. SLDC shall assess State level TTC and ATC and submit them to WRLDC. TTC and ATC shall be revised from time to time based on the commissioning of new elements and other grid conditions and shall be published on the websites of the SLDC with all the assumptions and limiting constraints.

    d. Operational planning study shall be done to assess whether the planned operations shall result in deviations from any of the system operational limits defined under these Regulations and applicable CEA Standards. The deviations, if any, shall be reviewed in the SOCC meeting and significant deviations shall be monitored for early resolution.

    e. SLDC shall maintain records of the completed operational planning study, including date specific power flow study results, the operational plan and minutes of meetings on operational study.

    f. SLDC shall have operating plans to address potential deviations from

system operational limit identified as a result of the operational planning study. These operating plans shall be communicated to Users in advance so that they can take corrective measures. In case any user is unable to adhere to such an operating plan, it shall inform the SLDC in advance with detailed reasons and explanations for the non-adherence. These detailed reasons and explanations shall be discussed in the SOCC meeting.

g. SLDC shall undertake a study on the impact of new elements to be commissioned in the intra-State system in the next six (6) months on the TTC and ATC for the State and share the results of the studies with WRLDC.

h. SLDC shall compare the results of the studies of the impact of new elements on the system and transfer capability addition with those of the interconnection and planning studies by CTU and STU, and any significant variations observed shall be communicated to CEA, WRPC, CTU and STU for immediate and long-term mitigation measures.

i. Defence mechanisms like system protection scheme, load-rejection scheme, generation run-back, islanding scheme or any other scheme for system security shall be proposed by the concerned user or SLDC and shall be deployed as finalized by SLDC / STU / WRPC.

8.12 System Restoration

1. SLDC shall prepare restoration procedure for the State grid, which shall be updated every year by SLDC taking into account changes in the configuration of State power systems.

2. SLDC in consultation with the WRLDC, STU, RPC and Users shall prepare detailed procedures for restoration of the State grid under partial and total blackouts, which shall be reviewed and updated annually by the SLDC.

3. Detailed procedures for restoration post partial and total blackout of each user system within a region shall be prepared by the concerned user in coordination with the SLDC. The concerned user shall review the procedure every year and update the same.

4. SLDC shall carry out a mocktrial run of the procedure for different sub-systems including black-start of generating units along with grid forming capability of inverter based generating station and VSC based HVDC black-start support at

least once a year under intimation to the WRLDC.

5. Diesel generator sets and other standalone auxiliary supply sources to be used for black start shall be tested on a weekly basis and the user shall send the test reports to SLDC on a quarterly basis.

6. Simulation studies shall be carried out by each user in coordination with SLDC for preparing, reviewing and updating the restoration procedures considering the following:
   a. Black start capability of the generator;
   b. Ability of black start generator to build cranking path and sustain island;
   c. Impact of block load switching in or out;
   d. Line/transformer charging;
   e. Reduced fault levels;
   f. Protection settings under restoration condition.

7. The thermal and nuclear generating stations shall prepare themselves for house load operation as per design. The concerned user and SLDC shall report the performance of house load operation of a generating station in the event where such operation wasrequired.

8. SLDC shall identify the generating stations with black start facility, grid-forming capability of inverter based generating stations, house load operation facility, inter-State or inter-regional ties, synchronizing points and essential loads to be restored on priority.

9. During the restoration process following a blackout, SLDC is authorized to operate with reduced security standards for voltage and frequency and may direct the implementation of such operational measures, namely, suspension of secondary or tertiary frequency control, power market activities, defence schemes, reduced governor droop setting as necessary, in order to achieve the fastest possible recovery of the grid.

10. All communication channels required for restoration process shall be used for the operational communication only till the grid normalcy is restored.

11. Distribution Licensees or Users with essential loads shall separately identify non-essential components of such loads, which may be kept off during system contingencies. Distribution Licensees shall draw up an appropriate schedule with corresponding load blocks in each case and assign relative priority in the

restoration of essential loads. The non-essential loads shall be put on only when system normalcy is restored, as advised by SLDC.

12. SLDC shall carry out the post-disturbance analysis of all major grid disturbances resulting into total or partial system blackout or system split and desynchronization of any part of the State Grid. All Users shall coordinate and furnish the data pertaining to the system disturbance to enable SLDC to analyse the system disturbance and furnish a report to RLDC in accordance with the provisions of IEGC, as amended from time to time.

13. PCC shall also review the data collected and analyse the failure of protection system either of In-STS or any User and recommend modification and/or improvement in the protection system or relay setting schemes if any.

14. Any entity extending black start support by way of injection of power as identified in these Regulations shall be paid for actual injection @ 110 % of the normal rate of charges for deviation in accordance with CERC DSM Regulations as amended from time to time for the last block in which the grid was available. The procedure in this regard as prepared by NLDC shall be followed.

8.13 System operation and Despatch:

1. The estimation of daily load demand on a day-ahead basis shall be carried out, in general,and furnished to the SLDC by the Intra-State entities, keeping in view the following aspects:

   (a) Outage Planning/scheduled rostering,

   (b) Historical data of load for the same month/day/time,

   (c) Previous day's demand,

   (d) Present weather conditions and meteorological reports,

   (e) Requirement of meeting important loads on festivals, etc.

   (f) Force Majeure conditions such as cyclones, earthquake, riots, etc.,

   (g) Vacations, Sundays and other holidays,

   (h) Number and frequency of breakdowns and their recovery period.

2. The State grid normally operates in synchronism with the western grid and the WRLDC has the overall responsibility of enforcing the grid discipline and managing the frequency in the region. SLDC shall follow the instructions of WRLDC in this regard for backing down / shutting down generation, regulating the load flow, etc., to meet the objective. SLDC shall accordingly instruct the generating companies to regulate their generation and hold reserves, if any, of Active and Reactive Power within their respective declared parameters to ensure that the grid frequency remains in the frequency band of 49.900- to 50.050 Hz. (frequency band as per prevailing IEGC).

3. The SLDC shall also regulate the load as may be necessary to meet this objective. The transmission system voltage levels can be affected by regional operation. STU shall optimize voltage management by adjusting the transformer taps to the extent available and switching the capacitors/reactors and take such other operational steps indicated in the GERC Power System Management Standards, 2005. SLDC shall also instruct the generators, including RE generators, to regulate the MVAr injection / absorption within their declared parameters. SLDC shall also instruct the Distribution Licensees and other entities to regulate their demand if necessary. The Distribution Licensees and other entities shall also participate in the voltage management by regulating their drawal and by installing compensatory equipment, as may be required. If acceptable voltage levels are still not reached by these measures, the Transmission Licensee shall take necessary steps to augment the voltage level such as strengthening of the Transmission System and/or installation of requisite reactive compensation equipment, building new lines, etc., to meet the voltage criteria.

4. The Distribution Licensee and other entities shall maintain a power factor of not less than 0.90 lag as required in the Distribution Code and furnish all the data required by the SLDC to ascertain the Reactive Power flow to their system. The SLDC may also instruct the Distribution Licensees and other entities to maintain appropriate power factor and take all measures in this regard.

5. WAMS for SLDC: WAMS is needed to keep up pace with the current technology as per need of time. It is essential for SLDC to establish full-fledged WAMS in line with SCADA, reliable multithread communication and IT infrastructure.

   The outline of WAMS shall be:

   (a) Phasor Measurement Unit (PMU) at critical locations and to ensure complete

gridobservability,

(b) Broadband communication between PMU at S/s and Phasor Data Concentrator (PDC)at SLDC,

(c) PMU data collection, analysis and observation utility,

(d) Advance application package like oscillation stability, transient stability, voltage stability and dynamic State Estimator to observe dynamic behavior of the system.

8.14 Metering and Protection

1. The metering and protection to be provided at the generating stations, sub-stations and the distribution systems shall meet the specific requirements of the Metering Regulations of CEA and Protection Standard under **Annexure 4**. This standard also forms an integral part of these Regulations. All Users shall cooperate with the STU to ensure correct and appropriate settings of protection to achieve an effective, discriminatory removal of faulty equipment within the target clearance time specified in this standard. Protective Relay settings shall not be altered, or protection bypassed and/or disconnected, without consultation and agreement of all the affected Users. In case where protection is bypassed and/or disconnected by agreement, then the cause must be rectified and protection shall be restored to normal condition, as quickly as possible. If agreement has not been reached, the electrical equipment shall be removed from service forthwith in case it is affecting the security of the system.

2. Fire Protection:

(a) All adequate precaution shall be taken and protection shall be provided against fire hazards to all apparatus in the system conforming to the relevant Indian Standard Specifications and/or provisions of CEA (Measures Relating to Safety and Electric Supply) Regulations, 2023 as amended from time to time.

8.15 Monitoring of Generation and Drawal

8.15.1 Monitoring Procedure

1. For the effective operation of the Transmission System, it is important that the declared availability of the generating company is realistic. SLDC shall

continuously monitor the generating unit outputs and bus voltages. More stringent monitoring shall be performed at any time when there are reasons to believe that the generating company's declaredavailability may not match with the actual availability, or declared output does not match with the actual output.

2. STU/ Transmission Licensee shall inform the generating company, in writing, if continual monitoring demonstrates an apparent persistent or material mismatch between the despatch instructions and the Generating Unit output or breach of the connection conditions. Further, more stringent monitoring shall be carried out by the SLDC, if agreement is not reached between the concerned parties on the performance of thegenerating unit. The results of stringent monitoring shall be reported by the SLDC to the generating company. Continual discrepancies shall be reported to the Commission for resolution.

3. The generating companies shall provide real time automatic data transfer facility to the sub-SLDC and should be compatible with the existing SCADA of sub-LDC. However, the generating companies shall provide to the SLDC, quarter-wise hourly generation summation outputs wherever no automatic transmitting metering or SCADA equipment exists. All the CPPs and RE generators with and without ESS (capacity above 1 MW) shall provide to the SLDC quarter-wise hourly export/import MW and MVAr. The generating company shall provide other logged readings, which the SLDC may reasonably require, for monitoring purposes wherever SCADA data is not available.

8.16 Monitoring of Drawal by the SLDC

1. The SLDC shall continuously monitor actual MW drawal (import/export) against the scheduled drawal from the generating companies, by the use of SCADA equipment wherever available, or otherwise using available metering. The SLDC shall request the WRLDC and adjacent states, as appropriate, to provide any additional data required to enable this monitoring to be carried out.

2. The SLDC shall also monitor the actual MVAr import/export. This will be used to assist in the voltage management in the Transmission System.

8.17 Generating Unit Trippings

1. The generating companies shall promptly inform the tripping of a generating unit and restrictions to generate full load, with reasons, to the SLDC in accordance with the guidelines given in the operational event/accident

reporting Chapter. The approximate and expected time of re-synchronisation with grid shall be informed to the SLDC. The SLDC shall keep a written log of all such trippings, including the reasons for the purpose of demonstrating the effect on system performance and identifying the need for remedial measures. The generating companies shall submit a detailed report of their unit trippings to the SLDC every month. While restoring the tripped units, SLDC shall be informed.

8.18 Data Requirements

1. The generating companies and the CPPs and RE generators with and without ESS shall submit the following data on monthly basisto the SLDC in the first week of every succeeding month:

   (a) Generating Companies:

      (i) Quarter-hourly generation and summation on real time basis,

      (ii) Logged readings of generating units as required,

      (iii) Detailed report of the generator unit trippings.

   (b) CPPs and RE generators with and without ESS (above 1 MW): Quarter hourly export/import MW on real time basis.

8.19 Real Time Operation

1. System state:

Power system shall be categorized under normal, alert, emergency, extreme emergency and restoration state depending on the type of contingencies and value ofoperational parameters of the power system by RLDC, NLDC or SLDC, as the case may be.

a. Normal state

Power system shall be categorized under normal state when the power systemis operating with operational parameters within their respective operational limits and equipment are within their respective loading limits. Under normal state, the power system is secure and capable of maintaining stability under contingencies defined in the CEA Transmission Planning Criteria.

b. Alert state

Power system shall be categorized under alert sate when the power system is operating with operational parameters within their respective operational limits, but a single contingency ('N-1') leads to a violation of security criteria. The power system remains intact under such alert state. However, whenever the power system is under alert state, the system operator shall take corrective measures to bring it back to a normal state.

c. Emergency state

Power system shall be categorized under emergency state when the power system is operating with operational parameters outside their respective operational limits or equipment are above their respective loading limits. Emergency state can arise out of multiple contingencies or any major grid disturbance in the system. The power system remains intact under such emergency state. However, whenever the power system is under emergency state, the system operator, to bring back the power system to alert/normal state, shall take corrective measures such as:

(i) Extreme measures such as load shedding, generation unit tripping, line tripping or closing,

(ii) Emergency control action such as HVDC Control, Excitation Control, HP-LP Bypass, tie line flow rescheduling on critical lines, and

(iii) Automated action such as system protection scheme, load curtailmentscheme and generation run-back scheme.

d. Extreme Emergency state

Power system shall be categorised under extreme emergency state if the control actions taken during the emergency state are not able to bring the system either to an alert state or a normal state and operational parameters are outside their respective operational limits or equipment are critically loaded. Extreme emergency state may arise due to high impact low frequency events like natural disasters. The power system may or may not remain intact (splitting may occur) and extreme events like generation plant tripping, bulk load shedding, under frequency load shedding (UFLS) and under voltage load shedding (UVLS) operation may

occur.

e. Restorative State

Power system shall be categorized under restorative state when control action is being taken to reconnect the system elements and restore system load. The power system transits from a restorative state to either an alert state or a normal state, depending on the system conditions.

2. SLDC shall carry out the study based on historical data and grid incidences and evolve detailed criteria to categorise the power system in terms of the above states. The detailed criteria shall be included in the Detailed Operating Procedure to be issued by SLDC.

3. SLDC shall maintain the grid in the normal state by taking suitable measures. In case the power system moves away from the normal state, appropriate measures shall be taken to bring the system back to the normal state. In case the power system has moved to an extreme emergency state, SLDC shall take emergency action and initiate restorative measures immediately.

4. Procedure to be followed during an event

   a. In the case of an event on the intra-State transmission system that may significantly impact the inter-State transmission system, the SLDC shall immediately inform the WRLDC;

   b. Any warning in respect of system security issued by SLDC shall be taken note of immediately by the concerned Users who shall take the necessary action to withstand the said event or to minimize its effect.

5. Operational coordination

   a. For operational coordination, each Intra-state transmission licensee, generating station and QCA shall have a control centre or coordination centre for round the clock coordination as specified in these Regulations.

   b. Any planned operation activity in the Intra-State transmission system [such as generating unit synchronization or de-synchronization, transmission element opening or closing (including breakers), protection system outage, SPS outage and testing etc.] shall be done by taking unique code from SLDC. This unique code shall have validity period of sixty (60) minutes from the

time of issue. In case such operation activity does not take place within the validity period of the code, the entity shall obtain a fresh unique code from SLDC.

8.20 Post Despatch Analysis

8.20.1 Operational analysis

1. SLDC shall analyse the following:

   a. Pattern of demand met, under drawals and over drawals, frequency profile, voltage and tie-line flows, angular spread, area control error, reserve margin, load and RE forecast errors, ancillary services despatched, transmission congestion and (n-1) violations;

   b. Generation mix in terms of source and station-wise generation;

   c. Irregular pattern in any of the system parameters mentioned in sub-clauses (a)(i) and (a)(ii) of this Regulation and reasons thereof; and

   d. Extreme weather events or any other event affecting grid security.

2. Such analysis shall be disclosed on SLDC website.

3. SLDC shall prepare a quarterly report that shall bring out the system constraints, reasons for not meeting the requirements, if any, of security standards and quality of service, along with details of actions taken, including by those responsible for causing disturbances in the system parameters.

4. SLDC shall also provide such a report to the STU, WRLDC / WRPC.

5. For the purpose of analysis and reporting, telemetered data shall be archived with a granularity of not more than five (5) minutes and higher granularity for special events. Such data shall be stored by SLDC for at least fifteen (15) years and reports shall be stored for twenty-five (25) years for operational analysis.

8.20.2 Event reporting

1. Event reporting shall make available adequate data to facilitate event analysis.

   a) Immediately following an event (grid disturbance or grid incidence as defined in the CEA Grid Standards) in the system, the concerned user shall

inform to SLDC through voice message.

b) The concerned user within the time line specified in Table 8 below shall submit written flash report to SLDC.

c) Disturbance Recorder (DR), station Event Logger (EL), Data Acquisition System (DAS) shall be submitted within the time line specified in Table 8 below.

d) SLDC shall report the event (grid disturbance or grid incidence) to WRPC and WRLDC within twenty-four (24) hours of receipt of the flash report.

e) After a complete analysis of the event, the user shall submit a detailed report in the case of grid disturbance or grid incidence within one (1) week of the occurrence of event to SLDC.

2. SLDC shall prepare a draft report of each grid disturbance or grid incidence including simulation results and analysis, which shall be discussed and finalized at the Protection sub-committee of RPC as per the timeline specified in Table below:

Table 8: Report Submission Timeline

\Sr. No.	**Grid Event^ (Classification)**	**Flash report submission deadline (Users/ SLDC)**	**Disturbance record and station event log submission deadline (Users/ SLDC)**	**Detailed report and data submission deadline (Users/ SLDC)**	**Draft report submission deadline (RLDC/ NLDC)**	**Discussion in protection committee meeting and final report submission deadline (RPC)**
1	GI-1/GI-2	8 hours	24 hours	+7 days	+7 days	+60 days
2	Near miss event	8 hours	24 hours	+7 days	+7 days	+60 days
3	GD-1	8 hours	24 hours	+7 days	+7 days	+60 days
4	GD-2/GD-3	8 hours	24 hours	+7 days	+21 days	+60 days
5	GD-4/GD-5	8 hours	24 hours	+7 days	+30 days	+60 days

^*The classification of Grid Disturbance (GD)/Grid Incident (GI) shall be as per the CEA GridStandards.*

a) The implementation of the recommendations of the final report shall be monitored by SLDC. SLDC shall disseminate the lessons learnt from each event to all Users for necessary action.

b) Any additional data such as single line diagram (SLD) of the station, protection relay settings, HVDC transient fault record, switchyard equipment and any other relevant station data required for carrying out analysis of an event by SLDC shall be furnished by the Users within forty-eight (48) hours of the request. All Users shall also furnish high-resolution analog data from various instruments including power electronic devices like HVDC, FACTS, renewable generation (inverter level or WTG level) on the request of SLDC.

c) Triggering of STATCOM, TCSC, HVDC run-back, HVDC power oscillation damping, generating station power system stabilizer and any other controller system during any event in the grid shall be reported to the SLDC, if connected to the intra-State system. The transient fault records and event logger data shall be submitted to the SLDC within 24 hours of the occurrence of the incident. Generating stations shall submit 1-second resolution active power and reactive power data recorded during oscillations to the SLDC within 24 hours of the occurrence of the oscillations.

d) A monthly report on events of unintended operation or non-operation of the protection system shall be prepared and submitted by each user to SLDC within the first week of the subsequent month.

8.21 Load Crash

1. In the event of load crash due to weather disturbance or any other reasons, SLDC shall control the situation by getting the following methods implemented by Distribution Licensee(s) and other Users in descending priorities:
   a) Lifting of the load restrictions, if any;
   b) Switching off BESS, if it is in discharge mode
   c) Backing down of thermal stations with a time lag of 5-10 minutes for a short period in merit order;
   d) Closing/Backing down of hydropower units (subject to non-spilling of water and effect on irrigation) keeping in view the inflow of water into canals and safety of canals/hydel channels.

e) Backing down of hydel stations for short period immediately
f) Backing down of Renewable Energy Power Plants:

Provided that any other instruction issued by WRLDC shall assume priority over such methods:

Provided further that such methods shall be reviewed from time to time by SOCC.

8.22 Periodic Reports

1. Daily / monthly reports covering the performance of the integrated grid shall beprepared by SLDC.

The reports shall, inter-alia, contain the following:

(a) Frequency profile;
(b) Source wise generation for each control area;
(c) Drawal from the ISTS grid and area control error;
(d) Demand and Supply situation;
(e) Demand met (peak, off-peak and average);
(f) Demand/Energy unserved in MW and MWh;
(g) Instances of inordinate delays in restoration of transmission elements and generating units;
(h) Instances and quantum of curtailment of renewable energy;
(i) Voltage profile of important substations and sub-stations normally having low or high voltage;
(j) Lines/Substations operating near thermal rating or rated capacity;
(k) Lines
(l) Major generation and transmission outages;
(m) Constraints and instances of congestion in the transmission system;
(n) Instances of persistent / significant non-compliance with the Grid Code;
(o) Status of reservoirs.
(p) Summary of ISTS transactions and In-STS Open Access transactions.
(q) Any other report as stipulated by the Commission from time to time.

2. SLDC shall provide operational feedback for grid planning and submit it to the STU.

8.23 Reactive Power Management

1. All Users shall endeavour to maintain the voltage at the interconnection point in the range specified in the Grid Code.

2. All generating stations shall be capable of supplying reactive power support to maintain power factor at the point of interconnection within the limits of 0.95 lagging to 0.95 leading as per the CEA Connectivity Standard Regulations.

3. All generating stations connected to the grid shall generate or absorb reactive power as per instructions of the SLDC within the capability limits of the respective generating units, where capability limits shall be as specified by the OEM.

4. The reactive interchange of the Users shall be measured and monitored by the SLDC.

5. SLDC may direct the Users about reactive power set points, voltage set points and power factor control to maintain the voltage at interconnection points.

6. SLDC shall assess the dynamic reactive power reserve available at various substations or generating stations under any credible contingency on a regular basis based on technical details and data provided by the Users, as per the procedure specified by SLDC.

7. SLDC shall take appropriate measures to maintain the voltage within limits, inter-alia, using the following facilities, and the facility owner shall abide by the instructions of SLDC:
   (i) Shunt reactors,
   (ii) Shunt capacitors (excluding HVDC automatic control),
   (iii) TCSC,
   (iv) VSC based HVDC,
   (v) Synchronous/non-synchronous generator voltage control including inverter based reactive power support,
   (vi) Synchronous condenser,
   (vii) Static VAR compensators (SVC), STATCOM and other FACTS devices,
   (viii) Transformer tap change: generator transformer and inter-connecting transformer,
   (ix) HVDC power order or HVDC controller selection to optimize filter bank.

8. Reactive power facility shall be in operation at all times and shall not be taken out without the permission of the SLDC.

9. Periodic or seasonal tap changing of power transformers and generator transformers shall be carried out to optimize the voltages, subject to technical feasibility, and where ever necessary, other options such as tap staggering may be carried out in the network.

10. Hydro and gas generating units having this capability shall operate in synchronous condenser mode operation as per instructions of SLDC. Standalone synchronous condenser units shall operate as per the instructions of SLDC. The compensation for such synchronous condenser mode operation shall be included in the procedure to be submitted by SLDC to the Commission for approval.

11. Any commercial settlement for reactive power shall be governed as per the regulatory framework specified by the Commission.

12. If voltages are outside the limit as specified in these Regulations and the means of voltage control set out in sub-clause (7) of these Regulations are exhausted, SLDC shall take all reasonable actions necessary to restore the voltages so as to be within the relevant limits including switching ON or OFF of lines considering the security of the system.

13. Notwithstanding the above, SLDC may direct the State entities to curtail VAr drawal/injection in case the security of grid or safety of any equipment is endangered.

14. In general, the State entities shall endeavour to minimize the VAr drawal at an interchange point when the voltage at that point is below 95% of rated voltage, and shall not return VAr when the voltage is above 105%. Transformer taps at the respective drawal points may be changed to control the VAr interchange only as per the instructions of SLDC.

15. Switching in/out of 400 kV bus and line reactors in the intra-state transmission grid shall be carried out as per instructions of RLDC/SLDC. Tap changing of all identified transformers shall be carried out as per SLDC instructions.

16. The Generating Station shall inject/absorb the reactive energy into the grid on the basis of machine capability as per the directions of SLDC:

Provided that in case injection/absorption of reactive energy is due to SLDC instructions, then commercial considerations shall be kept in abeyance for such period only in the case the SLDC instructions are given due to exigencies of the grid:

Provided further that the SLDC shall submit a monthly Report of all exigencies and the instances when the commercial considerations are required to be kept in abeyance.

17. The generating station shall change generator transformer taps and generate/absorb Reactive power as per the instructions of SLDC within the capability limits of the respective generating units, i.e., without sacrificing the active generation required at that time.

18. Wind generating stations connected to InSTS shall be capable of supplying dynamically varying reactive power support, so as to maintain power factor at their grid inter-connection point for all dispatch scenarios by providing reactive compensation as specified by the Authority from time to time.

19. STU and/or SLDC shall carry out load flow studies to predict where voltage problems may be encountered based on the operational data and identify appropriate measures to ensure that voltages remain within the defined limits. On the basis of these studies, SLDC may issue specific instructions to Users to maintain voltage level at interconnecting points within permissible limits. SLDC shall take appropriate measures to control InSTS voltages, which may include but not limited to power transformer tap changing, capacitor/reactor switching including capacitor switching by the distribution licensees at 66 kV and above, operation of hydro unit as synchronous condenser and use of MVAR reserves with generating stations within the technical limits agreed to between the STU and generators.

20. Generating Stations shall provide up to date capability curves for all Generating Units to the SLDC indicating any restrictions to allow accurate system studies and effective operation of the InSTS.

8.24 Periodic Testing

1. There shall be periodic tests, as required under clause (3) of these Regulations, carried out on power system elements for ascertaining the correctness of mathematical models used for simulation studies as well as ensuring desired

performance during anevent in the system.

2. **General provisions**

a. The owner of the power system element shall be responsible for carrying out tests as specified in these Regulations and for submitting reports to STU and SLDC for intra-State elements.

b. All equipment owners shall submit a testing plan for the next year to the SLDC by 30th September to ensure proper coordination during testing as per the schedule. In case of any change in the schedule, the owners shall inform SLDC in advance.

c. The tests shall be performed once every five (5) years or whenever major retrofitting is done. If any adverse performance is observed during any grid event, then the tests shall be carried out even earlier, if so advised by SLDC as the case may be.

d. The owners of the power system elements shall implement the recommendations, if any, suggested in the test reports in consultation with SLDC and STU.

3. Testing requirements

The following tests shall be carried out on the respective power system elements:

Table 9: Tests Required For Power System Elements

Power System Elements	Tests	Applicability
Synchronous Generator	(1) Real and Reactive Power Capabilityassessment. (2) Assessment of Reactive Power Control Capability as per CEA Technical Standardsfor Connectivity (3) Model Validation and verification test for the complete Generator and Excitation System model including PSS. (4) Model Validation and verification of Turbine/Governor and Load Control or Active Power/ Frequency Control Functions. (5) Testing of Governor performance and Automatic Generation Control.	Individual Unit of rating 100 MW and above for Coal/lignite, 50 MW and above gas turbine, and 25 MW and above for Hydro.

Power System Elements	Tests	Applicability
Non synchronous Generator (Solar/Wind)	(1) Real and Reactive Power Capability forGenerator (2) Power Plant Controller Function Test (3) Frequency Response Test (4) Active Power Set Point change test. (5) Reactive Power (Voltage / Power Factor / Q-Set Point change test	Applicable asper CEA Technical Standards for Connectivity.
HVDC/FACTS Devices	(1) Reactive Power Controller (RPC) Capabilityfor HVDC/FACTS (2) Filter bank adequacy assessment based on present grid condition, in consultation with NLDC. (3) Validation of response by FACTS devices as per settings.	To all ISTS HVDC as well as Intra-State HVDC/FACTS, as applicable

8.25 Capacity Building and Certification

Capacity building, skill upgradation, and certification of the personnel deployed in load despatch centres shall be done periodically under an institutional framework through accredited certifying agency(ies).

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9 Flexible Operation of Coal based Thermal Power Generating Units

9.1 Minimum power level capabilities of coal based thermal power generating units for flexible operation:

1. All coal based thermal power generating units owned or under control of the Central Government, State Governments or owned by any private company, connected with the grid and to the load despatch centres shall be capable of providing the flexible operation as per Regulation (6) of the Central Electricity Authority (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023 as amended from time to time.

2. SLDC shall schedule the coal based thermal power generating units, under its jurisdiction, considering the flexible operation capabilities as specified in the CEA (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023 as amended from time to time.

9.2 Ramp rates capabilities of coal based thermal power generating units for flexible operation

The coal based thermal power generating units shall have ramp rate capability as per the Regulation (7) of the Central Electricity Authority (Flexible Operation of Coal based Thermal Power Generating Units) Regulations, 2023 as amended from time to time.

9.3 Technical Minimum Schedule for operation of State Generating stations:

1. The technical minimum for operation in respect of a generating unit or units connected with Intra-State transmission system shall be 55% of MCR loading or installed capacity of the unit of generating station.

2. The State thermal generators shall be compensated depending on the average unit loading duly taking into account the forced outages, planned outages, PLF, generation at generator terminal, energy sent out ex-bus, number of start-stop, secondary fuel oil consumption and auxiliary energy consumption, in due consideration of actual and normative operating parameters of station heat rate, auxiliary energy consumption and secondary fuel oil consumption, etc., on monthly basis duly supported by relevant data verified by SLDC in accordance with GERC (MYT) Regulations, 2024 as amended from time to time for generators covered under Section 62 of the Act and provisions of the PPA with the beneficiaries for generators covered under Section 63 of the Act, as the case may

be:

Provided that:

In case of coal / lignite based generating stations, the station heat rate degradation or actual heat rate, whichever is lower, shall be considered for the purpose of compensation subject to provisions of GERC (MYT) Regulations, 2024 as amended from time to time and PPA with the beneficiary:

3. In case of coal / lignite based generating stations, the Auxiliary Energy Consumption degradation or actual, whichever is lower shall be considered for the purpose of compensation, subject to provisions of GERC (MYT) Regulations, 2024 as amended from time to time and PPA with the beneficiary:

4. Where the scheduled generation falls below the technical minimum schedule, the State generators shall have the option to go for reserve shut down and, in such cases, start-up fuel cost over and above seven (7) start / stop in a year shall be considered as additional compensation based on following norms or actual, whichever is lower subject to provisions of GERC (MYT) Regulations, 2024 as amended from time to time and PPA with the beneficiary:

5. In case of gas based intra-State Generating Station, compensation shall be decided based on the characteristic curve provided by the manufacturer and after prudence check of the actual operating parameters of Station Heat Rate, Auxiliary Energy Consumption, etc., subject to provisions of GERC (MYT) Regulations, 2024 as amended from time to time and PPA with the beneficiary.

6. There shall be reconciliation of the compensation at the end of the financial year in due consideration of actual weighted average operational parameters of station heat rate, auxiliary energy consumption and secondary oil consumption.

7. In case of a generating station whose tariff is neither determined nor adopted by the Commission, the concerned generating company shall have to factor the above provisions in the PPAs entered into by it for sale of power in order to claim compensations for operating at the technical minimum schedule.

8. The generating company shall keep the record of the emission levels from the plant due to part load operation and submit a report for each year to the Commission by 31st May of the year.

9. The Mechanism for Compensation for Degradation of Heat Rate, Aux Consumption and Secondary Fuel Oil Consumption, due to Part Load Operation and Multiple Start/Stop of Unit shall be as per the provisions of GERC (MYT) Regulations, 2024 as amended from time to time and PPA with the beneficiary and subject to approval of the Commission.

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10 Scheduling and Despatch Code

10.1 Scope

These Regulations will be applicable to SLDC, ALDC/ALDCs and all intra-State entities including conventional and RE Generators with or without ESS/ Captive Generating Plants CGP)/Independent Power Producers (IPPs) / Discoms / State transmission Utility (STU)/ Transmission licensees/ Standalone ESS and other beneficiaries of the State grid:

1. All Seller(s)/Generator(s), captive generators, open access generators, RE generators other than WS seller connected to In-STS having installed generating capacity of 5 MW and above of Unit or Combined capacity of all units in the generating station (or such other threshold capacity specified by the Commission from time to time).

   Provided In case of WS seller connected to in-STS, the matter related to Forecasting, Scheduling and deviation settlement related matters regarding wind and solar generation, wind-solar hybrid with or without ESS shall be governed as per the provisions of "GERC (Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources) Regulations 2019" and its amendments thereof.
2. All Buyer(s) including distribution licensee(s), deemed distribution licensee(s) located in the State and open access consumers connected to In-STS.
3. This Scheduling and Despatch code shall apply to all Intra-State Entity(ies), i.e., Buyers and Sellers connected to or using InSTS under its control area as defined in these Regulations.

10.2 Control Area Jurisdiction of Load Despatch Centre

1. The SLDC shall be responsible for optimum scheduling and despatch of electricity, monitoring of real time grid operations and management of the reserves including energy storage systems and demand response within its State control area, supervision and control over the intra-State transmission system, processing of interface energy meter data and coordinating the accounting and the settlement of State pool account, as may be specified by the Commission.
2. The entities connected exclusively to the intra-State transmission systems shall be under the control area jurisdiction of SLDC for scheduling and despatch of electricity.
3. Entities connected to both inter-State transmission systems and intra-State transmission systems shall be under the control area jurisdiction of RLDC, if more

than or equal to 50% of the quantum of connectivity is with ISTS, and if more than 50% of the quantum of connectivity is with intra-State transmission system, it shall be under the control area jurisdiction of SLDC.

4. In case an entity is connected to both inter-State transmission systems and intra-State transmission systems, the load despatch centre responsible for scheduling such entities shall coordinate with the concerned RLDC or SLDC, as the case may be, for ensuring grid security.
5. Unless otherwise decided by the Commission, the entities that have already declared COD as on the date of coming into force of these Regulations, shall continue to remain under the control area of the SLDC or the RLDC, as the case may be, as existing before the date of coming into force of these Regulations.
6. The entities participating in Ancillary Services must be capable of receiving the load set point signals from the WRLDC/SLDC or the NLDC as per CEA Technical Standards for Connectivity, or in terms of Ancillary Service Regulations, as applicable.

10.3 Roles and Responsibilities of SLDC:

1. In accordance with Section 33 of the Act, SLDC may give such directions and exercise such supervision and control as may be required for ensuring the integrated grid operations and for achieving the maximum economy and efficiency in the operation of power system in the State.
2. Every licensee, generating company, generating station, substation, User and any other person connected with InSTS shall comply with the directions issued by the SLDC under subsection (1) of Section 33 of the Act. The SLDC shall comply with the directions of the RLDC.
3. The SLDC in discharge of its functions under the Act and for stable, smooth and secure operation of the integrated grid, shall be responsible for the following in its control area:
   (a) Maintain Reactive Energy Account and any other account as specified by the Commission.
   (b) Optimum Scheduling and despatch for the entities in the State control area in accordance with contracts.
   (c) Forecasting demand for its control area for each time block on a day-ahead and intra-day basis.
   (d) Forecasting/planning of generation from wind, solar and other RE generating stations with or without ESS, which are intra-State entities, for each time block on day-ahead and intra-day basis:

Provided that such forecasts may be used by such generating stations at their own risk and discretion, along with all commercial liabilities arising out of them.

(e) Scheduling and despatch for all such generators located within the State and each entity in the State control area in accordance with contracts, which are not scheduled by RLDC.

(f) Secure operation of the grid by balancing demand and supply to minimize Area Control Error (ACE) for the State.

(g) Maintaining and dispatching reserves in accordance with relevant orders / Regulations.

(h) Real time monitoring of generating station's operation.

(i) Revision of availability declaration/requisition/demand/contracts and injection / drawal schedule.

(j) Switching instructions, outage planning.

(k) Metering and energy accounting and issuance of state energy account on monthly basis and deviation settlement mechanism account on weekly basis as per the prevailing Regulations.

(l) Collection and disbursement of various State energy accounts.

(m) Declaring Total Transfer Capability (TTC) and Available Transfer Capability (ATC) in respect of import and export of electricity of its control area with inter-State transmission systems in coordination with the Central Transmission Utility, State Transmission Utility, and WRLDC and revising the same from time to time based on grid conditions. Assessment of TTC and ATC shall be done on a continuous basis at least three (3) months in advance and revised based on contingencies from time to time.

(n) Incorporation of schedules for intra-State entities under collective transactions.

(o) Incorporation of schedules under the Ancillary Services Regulations.

(p) Optimization of scheduling inter-alia through Security Constrained Economic Despatch (SCED).

(q) Running a Security Constraint Unit Commitment (SCUC) for intra-State generating stations.

(r) In case, the Sellers/Buyers fail to furnish declared capacity / schedule within the prescribed time limits to SLDC, the SLDC may treat declared capacity/ schedule of such Sellers/Buyers as Zero.

10.4 Roles and Responsibilities of Generating stations / Sellers & DISCOMs / Buyers:

1. Generating Station / Sellers:
   Sellers shall be responsible for power generation/power injection as per the time block wise schedules finalized by SLDC in accordance with the provisions of these Regulations.
2. DISCOMs / Buyers:
   a. Provisions of this scheduling and despatch code shall be applicable for all Buyer(s) including distribution licensee(s), deemed distribution licensee(s), located in the State, and open access consumers connected to Intra-State transmission system.
   b. Buyers shall regulate their loads in a manner consistent with the provisions of the IEGC and the provisions of these Regulations.
   c. Buyer(s) or Seller(s) may request for revision of their schedule during intra-day operation in accordance with these Regulations.
   d. Buyers shall inform to SLDC, details of all contracts they have entered into for exchange of energy.
   e. Buyers including Distribution Licensees shall regularly carry out the necessary exercises regarding short-term Load estimation for their respective area, to enable them to plan in advance as to how they would meet their consumers' load without overdrawing from the grid.
   f. Buyers including Distribution Licensees shall furnish details of bilateral power they have contracted on short-term, medium-term, and long-term basis.
   g. Buyers shall furnish the details of their bi-lateral purchases and sources of power supply to SLDC.
   h. Buyers shall forecast the generation requirement for day ahead on 15-minute time block basis considering the availability declared by the Sellers with whom they have contractual arrangement.
   i. Buyers shall adhere to their schedule, if any deviation from it, SLDC may impose the restriction on drawal during system contingencies.
3. The system of each Discom shall be treated and operated as a notional control area. The algebraic summation of scheduled drawal from Generating stations and ISGS and any bilateral inter-change shall provide the drawal schedule of each Discom, and this shall be determined in advance on daily basis. The Discoms would generally be expected to regulate their consumers' load so as to maintain their actual drawal from the State grid close to the above schedules. The Discoms may, at their discretion, deviate from the drawal schedule, as long as such deviations do not cause system parameters to deteriorate beyond permissible limits and/or do

not lead to unacceptable line loading and unacceptable over drawal or under drawal.

4. The Discoms shall regularly carry out the necessary exercises regarding short-term and long-term demand estimation for their area. Every DISCOM has to submit to SLDC the load forecast on daily basis /weekly/Monthly/yearly basis for 15/5 minutes in advance as to how they would meet their consumers' load without overdrawing from the grid.
5. The Intra-State Generating Stations (SGS/ IPP/ CGP/RE, if scheduled) shall be responsible for power generation according to the daily schedules advised to them by the SLDC on the basis of the requisitions/demand received from the DISCOMs, and for proper operation and maintenance of their Generating Station, such that these stations achieve the best possible long-term availability and economy.
6. Each Intra-State entity shall regulate its generation or demand or both, as the case may be, so as to adhere to the schedule of net injection into or net drawal from the Intra-State transmission system.
7. Entitlement of a buyer and beneficiary:
   a. In cases of allocation of power from a central generating station by the Central Government and for State generators by GUVNL Holding Company, each beneficiary shall be entitled to MW despatch out of the declared capacity of such a generating station, in proportion to its share allocation given by GUVNL.
   b. For all other cases not covered as above of this Regulation, the buyer shall be entitled to MW despatch out of the declared capacity of intra-State generating station as per the contracts between seller and buyer.
   c. The entitlement from the regional and intra-State generating station shall be rounded off up to two decimal points for the purposes of scheduling and accounting.
8. Requirement for Commencement of Scheduling:
   Following documents shall be submitted to SLDC by generators/sellers or buyers as the case may be, before commencement of scheduling of transaction under LTOA/MTOA.

   (a) For all generators other than RE-
   (i) Technical details of the plant:
   (ii) Plant name
   (iii) Number of Generating Units and their capacity
   (iv) Total Installed Capacity (MW)
   (v) Maximum possible Ex-bus injection (MW)

(vi) Auxiliary consumption in percentage (%)
(vii) Minimum turn down level (MW) and in percentage (%)
(viii) Type of fuel
(ix) Fixed Cost (paise / kWh)
(x) Variable Cost (Paise / kWh)
(xi) Ramp-Up Rate (MW/Min) for each unit
(xii) Ramp-Down Rate (MW/Min) for each unit
(xiii) Start- up Time from Cold Start, Hot start and Warm Start of each unit (in Min)
(xiv) OEM document regarding all technical parameters justification
(xv) PPA /contract copy with effective date and its amendments if any with effective date.
(xvi) Connectivity agreement / BPTA.
(xvii) COD Date

(b) For Wind, Solar, wind-solar hybrid generators, with or without ESS

The following documents shall be submitted to SLDC before proposed date of commencement of first-time charging activities by Generators/QCA:

(i) Covering letter.

(ii) Name of Pooling Station, installed capacity of project and storage, if any, Name of connected Sub-Station of GETCO/Transmission Licensee.

(iii) Proposed date of synchronization of pooling station with Intra-State grid.

(iv) Details of contact person, i.e., Name, Designation, Mobile No., Email for day-to-day as well as commercial communication purpose.

(v) Details of first-time grid connection charge paid to SLDC through online mode.

(vi) Name of DISCOM for allocation of power from the project / type of contract in detail.

(vii) Copy of application to GEDA for granting registration of Wind, Solar Hybrid and ESS Power

(viii) Project, details of pooling station and specific details regarding under which Policy/Order/Regulation, the wind-solar capacity in the hybrid project is installed.

(ix) Approval obtained from various statutory agencies, i.e., STU/GEDA/DISCOM for installation and feasibility of pooling station of the project, as applicable.

(x) Parallel connectivity approval from STU/DISCOM, as applicable.

(xi) Approved metering scheme, ABT meter details, commissioning /MOM, as applicable.

(xii) Connectivity agreement with GETCO/ Discom or Transmission and /or Wheeling Agreement, as applicable.

(xiii) Copy of PPA/Wheeling agreement/Agreement for Third Party Sale with beneficiary, if any.

(xiv) Registration certificate of the generating unit or station in the registry maintained by CEA on e-portal https://egen.cea.gov.in as per applicable CEA standards.

(xv) Copy of letter allocating seven-digit ABT Meter Serial Number along with duly notarized undertaking as applicable.

(xvi) RTU commissioning report/MOM- for communication of real time data up to sub SLDC/SLDC and RTU payment receipt/, as applicable.

(xvii) Registration of renewable generators with SLDC through self/lead generator/QCA, as per approved procedure of Notification No. 1 of 2019 Dated. 19.01.2019

(xviii) Application for registration with registration charges/Consent from renewable generators (in case of QCA) /Undertaking from QCA (in case of QCA)/ Authorization to lead generator (in case of group generator)

(xix) Details of Payment Security provided by the project developer

(xx) Static Data of Renewable Energy Generator and Other supporting documents, as per requirement

(xxi) Consent / Concurrence letter for "Generator Name" being Lead Generator by all Generators, if applicable.

(xxii) Details of ALMM certificate issued by concerned authority, if applicable.

(xxiii) QCA appointment letter, as applicable.

(xxiv) On commissioning of Wind-Solar Hybrid Project with storage, if any, as per the certificate issued by GEDA and also signed by Discoms and/or Transmission Licensee/STU representatives, the details of plant with commissioning date, installed capacity (AC/DC both), DISCOM name for allocation of power, in tabular format with covering letter, to be submitted.

(xxv) C.O.D. letter of GEDA.

9. Scheduling of the generating station or unit thereof shall start from 00:00 hours of D+2 day (where D is the intimation of commercial operation date to SLDC of the said generating station or unit thereof).
10. Adherence to Schedule:
    Each intra-State entity shall regulate its generation, demand, or both, as the case may be, to adhere to the schedule of net injection into or net drawal from the intra-State transmission system for intra-State transaction and from inter-State transmission system for inter-State transactions.
11. The SLDC shall keep their Area Control Error close to zero (0) by rescheduling, deploying reserves and automatic demand management scheme.
12. Declaration of Declared Capacity by state entity generating stations:
    The State generating station other than the wind, solar, wind-solar hybrid generators with or without ESS shall declare ex-bus Declared Capacity limited to 100% MCR less auxiliary power consumption, on day ahead basis:
    Provided that the hydro generating stations may declare ex-bus Declared Capacity more than 100%, MCR less auxiliary power consumption limited to overload capability.
13. Wind, solar, wind-solar hybrid, with or without ESS generator, shall declare the available capacity /schedule on day ahead basis, as well as intra-day as per the provisions in GERC (Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources) Regulations, 2019 as amended from time to time.
14. The intra-State generating stations other than wind, solar, wind-solar hybrid, with or without ESS may be required to demonstrate the declared capacity of their generating stations as and when directed by SLDC. For this purpose, SLDC, in coordination with its beneficiaries, shall schedule the intra-State generating station up to its declared capacity as declared on day ahead basis.

15. The schedule issued by the SLDC shall be binding on the beneficiaries for such testing of the declared capacity of the State generating station. In case the generating station fails to demonstrate the declared capacity, it shall be treated as a mis-declaration for which charges shall be levied on the generating station as follows:

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

10.5 Ramping Rate to be Declared for Scheduling:

The Intra-State generating station shall declare the ramping rate in the following manner, which shall be accounted for in the preparation of generation schedules:

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

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

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

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

v. All the generators have to declare and intimate to SLDC in advance the ramp up/down per blocks of 15 minutes / 5 Minutes and have to follow the same strictly.

10.6 Optimum Utilization of Hydro Energy:

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

2. During high inflow and water spillage conditions, SLDC shall allow scheduling of power from hydro generating stations for overload capability up to 10% of Installed Capacity or any other limit as per sub-clause (1) of this Regulation, subject to the availability of margins in the Intra-State transmission system.

10.7 Minimum turndown level for Intra-state generating stations:

1. The minimum turndown level for operation in respect of a unit of a Intra-State generating station shall be 55% of the MCR of the said unit or such other minimum power level as specified in the CEA (Flexible Operation of coal based Thermal Generating Units) Regulations, 2023, as amended from time to time, whichever is lower:

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

   Provided further that such generating station on its own option may declare a minimum turndown level below the minimum turndown level specified in this Regulation:

   Provided also that the Intra-State thermal generating stations whose tariffs are determined under Section 62 shall be compensated for part load operation, that is, for generation below the normative level of operation, in terms of the provisions of the Order/MYT Regulations as amended from time to time of the Commission. In case of Intra-state thermal generating stations covered under section 63, the compensation for part load operation shall be governed as per the provisions of contract entered into by such generating stations with the beneficiaries or buyers.
2. The drawal of power requirements during non-generation hours, whether before or after COD, a generating station, including renewable energy generating station, shall be governed by the applicable Order/ Regulations of the Commission.

10.8 SECURITY CONSTRAINED UNIT COMMITMENT (SCUC)

1. The objective of Security Constrained Unit Commitment (SCUC) is to commit a generating station or unit thereof, for the maximization of reserves in the interest of grid security, without altering the entitlements and schedule of the buyers of the said generating station in the day ahead time horizon.
2. At 10:00 Hrs of (D-1) day, SLDC will decide the running of generating units to be on bar for the next day (D day) with assured technical minimum schedule of the intra-State generators.

3. Base on the load forecast given by ALDCs of Distribution Licensee or other entity, in case SLDC anticipates the reserves for the next day is not sufficient to mitigate the demand, SLDC may instruct the generating station to take on bar based on the cold, warm, hot condition of the generator and generator has to give the precise declared capacity and schedule, considering the ramp rate of the generator.
4. For the Interstate transactions, the provision of IEGC 2023 as amended from time to time shall be applicable.
5. UNIT RESERVED SHUT DOWN:
   (a) Base on the load assessment, as per submission by ALDCs of distribution licensees or other entity, if any generation is more than required, then SLDC can withdraw the running generating units under shut down.
   (b) If there is sudden load drop or in case of sudden increase in RE generation or observing high RE generation trend, then SLDC may withdraw running generating units.
   (c) In case of emergency conditions, for reasons of grid security, a generating station or unit thereof, which is under USD may be directed by SLDC or RLDC, as the case may be to come on bar, and in such event, the generating station or unit thereof shall come on bar under hot, warm and cold conditions as per the time period specified by the respective OEM, which shall be declared by generators and documented by SLDC.

10.9 SCHEDULING FROM ALTERNATE SOURCE OF POWER BY A GENERATING STATION:

1. A generating station may supply power from alternate source of power in case of forced outage of generators for beneficiaries.
2. It is compulsory to arrange power from alternative source when the generators / generating station goes under forced outage which is having inter-State bilateral as well as collective transactions to avoid unscheduled deviation at State periphery.
3. The methodology for the above incident, the generating station has to follow the following steps:
   a) The generating station may enter into contract with alternate supplier under bilateral transaction or collective transaction through SLDC.
   b) In case of bilateral transaction, the generating station shall request SLDC to schedule power from such alternate supplier to its beneficiaries, which shall become effective from 7^{th} or 8^{th} time blocks, as the case may be.

c) In case unit goes under forced outage having liabilities to supply contracted capacity to beneficiaries and if the generating station approaches SLDC for allowing supply from the alternate State power source, the same shall be effective from 7th / 8th time block.

d) If the alternative power source is outside the State, then generators can request to RLDC with intimation to SLDC to schedule power from such alternate supplier to its beneficiaries, i.e., concerned state drawal, which shall become effective from 7th or 8th time blocks, as the case may be, as per provision in IEGC –2023, as amended from time to time.

e) The power scheduled from alternate supplier shall be reduced from the schedule of the concerned generating station.

f) In case alternate supply is arranged through collective transactions, the transacted quantum shall be reduced from the scheduled generation of the generating station.

g) In case of a generating station whose tariff is determined by the Commission under Section 62 of the Act, supply of power by such generating station to its buyer from an alternate source, shall be as per provisions of Tariff Regulations and until a provision is made in the applicable MYT Regulations as amended from time to time, in accordance with the agreement between buyer and seller .

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

i) The generating station shall not be required to pay the transmission charges and losses for such purchase of power to supply to the buyer from alternate sources.

10.10 Security Constrained Economic Despatch (SCED)

1. The objective of Security Constrained Economic Despatch (SCED) is to optimize generation despatch after gate closure in the real time market and after finalization of schedules under real time market, by incrementing generation from the generating stations with cheaper charge and decrementing commensurate generation from the generating station with higher charge, after

considering the operational and technical constraints of generation and transmission facilities.

2. SLDC shall be the nodal agency for implementing SCED for the generating stations connected to intra-State transmission system, which are willing to participate under SCED.
3. The SLDC shall prepare a detailed procedure for implementation of SCED for the State and submit the same to the Commission for approval.

10.11 Margins for primary response:

1. For ensuring primary response, SLDC shall not schedule the generating station or unit(s) thereof beyond ex-bus generation corresponding to 100% of the Installed capacity of the generating station or unit(s) thereof. The generating station shall not resort to Valve Wide Open (VWO) operation of units, whether running on full load or part load, and shall ensure that there is margin available for providing governor action as primary response.
2. In case of gas or liquid fuel-based units, suitable adjustment in Installed Capacity shall be made by SLDC, as the case may be, for scheduling in due consideration the prevailing ambient conditions of temperature and pressure vis-à-vis site ambient conditions on which installed capacity of the generating station or unit(s) thereof have been specified:

Provided that the hydro generating stations shall be permitted to schedule ex-bus generation corresponding to 110% of the installed capacity or any other overload capability during high inflow periods to avoid spillage.

10.12 Procedure for Scheduling and Despatch for Intra-State Transactions:

1. This section deals with the procedure for scheduling and despatch for long-term, medium-term and short-term open access (to be read with provisions of GERC Open Access Regulations, 2011 as amended from time to time).
2. The scheduling procedure for medium-term open access transactions shall be similar to the scheduling procedure for long-term access transactions and as given below, except where it is specifically mentioned for collective transactions and inter-State bilateral transactions.
3. All intra-State generating stations (SGS) shall be duly listed on the SLDC web-sites. The station capacities and allocated/contracted shares of different beneficiaries shall also be listed out.

4. The following scheduling related activities shall be carried out daily for State/regional entities, on day ahead basis, 'D-1' day, for supply of power on 'D' day, as follows:

(a) Declaration of Declared Capacity by generating stations:

(i) The generating station based on coal and lignite shall submit the following information for 0000 hours to 2400 hours of the 'D' day, by 6:00 AM on 'D-1' day:

I. Time block wise Unit wise status
II. Time block-wise On-bar Ex-bus Declared Capacity (MW) for on-bar units;
III. Time block-wise Off-bar Ex-bus Declared Capacity (MW) for off-bar units;
IV. Time block-wise Ramp up rate (MW/min) for on-bar capacity;
V. Time block-wise Ramp down rate (MW/min) for on-bar capacity;
VI. MWh capability for the day;
VII. Minimum turndown level (MW) and in percentage (%) of ex-bus capacity on-bar.

(ii) The generating station based on hydro energy shall submit the following information for 0000 hours to 2400 hours of the "D" day, by 6 AM on "D-1" day:

I. Time block-wise ex-bus declared capacity;
II. MWh capability for the day;
III. Ex-bus peaking capability in MW and MWh;
IV. Time block-wise Ramp up rate (MW/min) for on-bar capacity;
V. Time block-wise Ramp down rate (MW/min) for on-bar capacity;
VI. Unit-wise forbidden zones in MW and percentage (%) of ex-bus installed capacity;
VII. Minimum MW and duration corresponding to requirement of water release for irrigation, drinking water and other considerations.
VIII. Unit wise maximum MW along with probable combination of unit maximum in case adequate water is not available.

(iii) The generating station based on gas or combined cycle generating station shall submit the following for 0000 hours to 2400 hours of the "D" day, by 6 AM on „"D-1" day

I. Time block-wise On-bar Declared Capacity (DC) for the station in MW separately for each fuel such as domestic gas, RLNG or liquid fuel and On-bar units;
II. Time block wise Off-bar Declared Capacity (MW) and off-bar units;

III. MWh capability (fuel-wise) for the next day;
IV. Time block wise Ramp up rate (MW/min) for on-bar capacity;
V. Time block wise Ramp down rate (MW/min) for on-bar capacity;
VI. Minimum turndown level (MW) and in percentage (%) of ex-bus capacity on-bar.

(iv) The State connected entity renewable energy generating station with or without ESS, individually or represented by a lead generator or QCA, covered under GERC (Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources) Regulations, 2019 as amended from time to time, shall submit aggregate available capacity of the pooled generation and aggregate schedule along with contract-wise breakup for each time block for 0000 hours to 2400 hours of the "D" day, by 6:00 AM on "D-1" day. The source wise breakup of aggregate available capacity of the pooled generation shall also be furnished as provided under GERC (Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources) Regulations, 2019 and amendments from time to time.

(v) ESS including pumped storage plant, individually or represented by the lead ESS or QCA on their behalf, shall submit aggregate available capacity of the pooled generation and aggregate schedule along with contract-wise breakup for each time-block for 0000 hours to 2400 hours of the 'D' day, by 6:00 AM on 'D-1' day. The source-wise breakup of aggregate available capacity of the pooled generation shall also be furnished.

(vi) The availability declaration by State entity generating station shall have a resolution of two decimal (0.01) MW and three decimal (0.001) MWh.

(b) Entitlement of each beneficiary or buyer:

(i) For generating station, where State own generators, IPPs, UMPPs having agreement with concerned DISCOMs for allocation of power from such generating stations, each DISCOM shall be entitled to a MW despatch up to its Share in the station's declared capacity (including On-bar Declared Capacity and Off-bar Declared Capacity) for the day. Accordingly, based on declared capacity of such generating station, SLDC shall declare entitled share of each beneficiary or buyer for 0000 hours to 2400 hours of the 'D' day, by 7:00 AM on 'D-1' day.

(ii) The generating station other than those having allocation of power under PPA with DISCOMs shall indicate the declared capacity along with respective share of the beneficiary (ies) or user embedded to DISCOMs,

in accordance with the contracts / arrangements entered with them. Based on the declared capacity of such generating station and share of the beneficiaries or buyers as indicated by such generating station, SLDC shall declare share of each beneficiary or buyer for 0000 hours to 2400 hours of the 'D' day, by 7:15 AM on 'D-1' day.

(iii) DISCOMs/ Beneficiaries/ user have to submit their Demand/Requisition to SLDC by 7:30 AM on 'D-1' day.

(c) The mutually agreed requisition for scheduling of intra-State entities for inter-State transaction shall be as submitted by the regional entity buyers or regional entity sellers in accordance with the contracts entered between them by 7:30 AM on 'D-1' day at RLDC.

(d) SLDC shall take into account the quantum of secondary and tertiary reserves in the State control area for the 'D' day by 8 AM of 'D-1' day, if any.

(e) The information regarding the foreseen availabilities of the generation from all types of generators and source and demand of the intra-State entities which are drawee GNA grantees shall be furnished time block-wise requisition for drawal to SLDC in accordance with the contracts, by 7:30 AM of 'D-1' day for further submission to WRLDC.

(f) The SLDC on behalf of the intra-State entities, which are drawee GNA grantees, as well as other drawee GNA grantees while furnishing time block-wise requisition under these Regulations shall subject to technical constraints, duly factor in merit order of the generating stations with which it has entered into contract(s):

Provided that the renewable energy generating stations shall not be subjected to merit order despatch, and subject to technical constraints shall be requisitioned first followed by requisition from other generating stations in merit order.

(g) Allocation of corridors by RLDC for GNA grantees:

(i) SLDC shall check if drawal schedules as requisitioned by drawee GNA grantees can be allowed based on available transmission capability:

Provided that in case of constraint in transmission system, the available transmission corridor shall be allocated to the drawee GNA grantees in proportion to their GNA within the region or from outside region, depending upon the transmission constraint, whether it is within the region or from outside the region, as the case may be. The same shall be intimated to drawee GNA grantees by 8.15 AM on 'D-1' day.

(ii) SLDC/ Drawee GNA grantees shall revise their requisition for drawal schedule based on availability of transmission corridors for such grantee by 8:30 AM on 'D-1' day, as applicable.

(iii) RLDC shall issue final drawal schedules for the State with incorporating drawal and injecting GNA grantees of the State by 9:00 AM on 'D-1' day,

(h) Requisition of schedule by T-GNA grantees at RLDC level:

(i) Based on the entitlement or otherwise, SLDC on behalf of intra-State entities which are T-GNA grantees, shall furnish time block-wise requisition for drawal, to the RLDC in accordance with contracts by 9:00 AM of 'D-1' day.

(ii) Other drawee T-GNA grantees, who are regional entities, shall furnish time block-wise requisition for drawal to RLDC in accordance with contracts by 9:00 AM of "D-1" day.

(iii) Allocation of corridors by RLDC for T-GNA grantees: RLDC shall check if drawal schedules as requisitioned by T-GNA grantees can be granted based on available transmission capability after allocating corridors to the GNA grantees:

Provided that in case of constraint in transmission system, the available transmission corridor shall be allocated to the T-GNA grantees in proportion to their T-GNA by RLDC.

(iv) RLDC/SLDC shall issue final drawal schedules for T-GNA grantees by 9.45 AM of "D-1" day.

(i) RLDC shall release the balance corridors after finalization of schedules for GNA and T-GNA grantees for day ahead collective transactions.

(j) The generating station whose tariff is determined under Section 62 of the Act, may sell its un-requisitioned surplus as available at 09:45 AM in the day ahead market. The sharing of net savings shall be as per provisions of Tariff Regulations and until a provision is made in the Tariff Regulations, in accordance with the agreement between buyer and seller.

(k) Scheduling of collective transactions:

The scheduling of collective transactions by State entities shall be in accordance with IEGC as amended from time to time, providing as under:

(i) Power Exchange(s) shall open bidding window for day ahead collective transactions and TRAS from 10.00 AM to 11:00 AM of 'D-1' day.

(ii) The power exchange shall submit the day-ahead provisional trade schedules along with net power interchange of each bid area and region to NLDC by 11:.45 AM of 'D-1' day.

(iii) NLDC shall validate the same from system security angle and inform the power exchange with revisions required, if any, due to transmission congestion or any other system constraint by 12:15 hrs of 'D-1' day.

(iv) The power exchange shall submit the final trade schedules to NLDC for regional entities and to SLDC for intra-State entities by 13:00 hrs of 'D-1' day.

(l) RLDC shall release balance corridors after finalization of schedules under day ahead collective transactions by 13:00-hrs of 'D-1' day.

(m) RLDC shall process exigency applications received till 13:00 hrs of 'D-1' day for the 'D' day by 14;00 hrs of 'D-1' day.

(n) RLDC shall update the availability of balance transmission corridors, if any, after finalization of schedules for exigency applications by 14:00 hrs of "D-1" day on its website. The balance transmission corridor may be utilized by GNA grantees by way of revision of schedule, under any contract within its GNA or for exigency applications or in real time market on first cum first serve basis.

(o) In consideration with aforesaid provisions of IEGC, the GNA Schedule and T GNA schedule of RLDC, collective transaction of intra-State entities data received from power exchanges, SLDC shall issue final drawal schedule and injection schedule of the State entities on 13:30 Hrs. of D-1 day, incorporating as under:

(i) the ex-power plant despatch schedule to each of the generating stations, in MW for different time blocks, for the next day. The summation of the ex-power plant drawal schedules advised by all beneficiaries shall constitute the ex-power plant station-wise despatch schedule

(ii) the net drawal schedule to each intra-State entity, in MW, for a different time block, for the next day. The summation of the station-wise ex-power plant drawal schedule for all generating station and ISGS/SGS and drawal schedules consequent to bilateral inter-changes, after deducting the transmission losses (estimated) shall constitute the entity-wise drawal schedule.

(iii) While finalizing the above daily despatch schedule for the generating station, SLDC shall ensure that the same is operationally reasonable, particularly in terms of ramping rates and the ratio between minimum and maximum generation levels.

(p) ALDCs shall inform any modifications/changes to be made in drawal schedule, if any, to SLDC by 13:45 hrs, or preferably earlier.

(q) Base on the submission of ALDCs, SLDC shall review and submit the change in requisition, if any at 14:00 hrs from the inter-State generating station for Gujarat drawal.

(r) Since the variation of generation in run of river power stations shall lead to spillage, these shall be treated as must run stations. All renewable generators except biomass, ESS, and bagasse generators whose tariff is determined by GERC shall be treated as must run power generators and shall not be subjected to merit order despatch as conventional generators.

(s) While finalizing the drawal and despatch schedules as above, SLDC shall also check that the resulting power flow does not cause any transmission constraints. In case any transmission constraints are foreseen in the system, the SLDC shall moderate the schedule to the required extent, with intimation to concerned State entities.

(t) If SLDC observes that the ramp rate of pick up or pick down is not as per the prescribed ramp rate for picking up and picking down to generator, then the SLDC can ask generator to take corrective actions accordingly.

(u) All State generators shall ramp up/down their generation corresponding to designed ramp rate or CEA prescribed ramp rate, whichever is higher, as per the injection schedule given by SLDC/RLDC, to avoid the DSM at boundary level of State.

(v) Procedure for scheduling of transaction in Real-time market (RTM):

The procedure for scheduling of transactions in Real-time market by State entities shall be in accordance with IEGC as amended from time to time, providing as under:

(i) All the entities participating in the real-time market including TRAS may place their bids and offers on the Power Exchange(s) for purchase and sale of power.

(ii) The window for trade in real-time market for day (D) shall open from 22:45 hrs to 23:00 hrs of (D-1) for the delivery of power for the first two time-blocks of 1st hour of day (D) i.e., 00:00 hrs to 00:30 hrs, and will be repeated every half an hour thereafter.

(iii) NLDC shall indicate to the Power Exchange(s) the available margin on each of the transmission corridors before the gate closure.

(iv) The power exchanges shall clear the real-time bids from 23:00 hrs till 23:15 hrs of 'D-1' day based on the available transmission corridor and the buy and sell bids for the real time market (RTM) for the specified duration and intimate the cleared bids to NLDC by 23:15 hrs, for scheduling**.**

(v) NLDC shall finalize schedules under RTM, SCED and Ancillary Services by 23:30 hrs. of 'D-1' day and RLDC shall publish the final schedules for dispatch by 23:35 hrs. of 'D-1'day. SLDC shall take into account the schedule released by the concerned RLDC for their intra-State entities and finalize the intra-State schedule by 23:50 hrs of D-1 day for the D day.

5. All requisitions and schedules shall be rounded off to the nearest two decimals for each of the transaction and shall have a resolution of 0.01 MW.
6. While making or revising its declaration of capability, except in case of run-off river (with up to three-hour pondage) hydro stations, the SGS shall ensure that the declared capability during peak hours should not be less than that during other hours. However, exception to this rule shall be allowed in case of tripping/re-synchronization of units as a result of forced outage of units. It shall be incumbent upon the generating station to declare the plant capabilities faithfully, i.e., according to their best assessment. In case, it is suspected that they have deliberately over/under declared the plant capability contemplating to deviate from the schedules given on the basis of their capability declarations (and thus make money either as undue capacity charge or as the charge for deviations from schedule), the SLDC may ask the generating station to explain the situation with necessary back-up data.
7. The quantum of penalty for the first mis-declaration for any duration/block in a day shall be the charges corresponding to two days' fixed charges. For the second mis-declaration, the penalty shall be equivalent to fixed charges for four days and for subsequent mis-declarations, the penalty shall be multiplied in geometrical progression over a period of a month.
8. In case of forced outage of unit, the SLDC shall revise the schedule on the basis of revised declared capacity. The revised declared capacity and the revised schedule shall become effective from the 7^{th} / 8^{th} time block, as the case may be, counting the time block in which intimation of the revision is received from the generating station to be the first one.
9. In the event of a bottleneck in evacuation of power due to any constraint, outage, failure or limitation in the transmission system, associated switchyard and substations owned by the STU or any other transmission licensee involved in intra-State transmission (as certified by the SLDC) necessitating reduction in generation, the SLDC shall revise the schedules, which shall become effective from the 7^{th} / 8^{th} time block, counting the time block in which the bottleneck in evacuation of power has taken place to be the first one. Also, during the 1^{st} , 2^{nd} and 3^{rd}', 4^{th}, 5^{th}, and 6^{th} time blocks of such an event, the scheduled generation

of the generating station shall be deemed to have been revised to be equal to actual generation, and the scheduled drawals of the beneficiaries shall be deemed to have been revised accordingly

10. In case of any grid disturbance, scheduled generation of all the generating stations and scheduled drawal of all the beneficiaries of intra-state transactions shall be deemed to have been revised to be equal to their actual generation/drawal for all the time blocks affected by the grid disturbance. Certification of grid disturbance and its duration shall be done by the SLDC based on the certification done by WRPC for the same incident:

    Provided that such relief shall be extended to intra-State Generator only if Gujarat State is excluded for the DSM mechanism by WRPC/RLDC for the certified incident.

11. In case of any grid disturbance of GD-5 category as defined in CEA Grid Standards impacting inter-State bilateral or collective transactions of Intra-State entities, it shall be governed by the IEGC-2023 as amended from time to time.
12. Revision of declared capability by the generating station having two-part tariff with capacity charge and energy charge (except hydro stations) and requisition by beneficiary(ies) for the remaining period of the day shall also be permitted with advance notice, but only in case of a contingency. Revised schedules/ declared capability in such cases shall become effective from the 7^{th} / 8^{th} time block, counting the time block in which the request for revision has been received by the SLDC to be the first one.
13. In case of forced outage of a unit having a short-term bilateral transaction (within intra-State), the generator shall immediately intimate the same along with the requisition for revision of schedule and estimated time of restoration of the unit, to SLDC as the case may be. The consent of the buyer shall not be a pre-requisite for such revision of schedule. The schedule of the generator and the buyer shall be revised, accordingly. The revised schedules shall become effective from the 7^{th} / 8^{th} time block, counting the time block in which the forced outage is declared and intimated to SLDC for request of revision to be the first one. The SLDC shall inform the revised schedule to the seller and buyer. However, the transmission and operating charges shall continue to be paid as per original approval.
14. At any point of time, the SLDC observes that there is need for revision of the schedules in the interest of better system operation due to huge variation of load, or huge variation in generation of RE generators, it may do so on its own, and in such cases, the revised schedules shall become effective from the 2^{nd}

time block, counting the time block in which the revised schedule is issued by the SLDC to be the first one.

15. To discourage frivolous revisions, SLDC may, at its sole discretion, refuse to accept schedule/capability changes of less than two (2) percent of previous schedule/capability. The schedule of thermal generating stations indicating fuel shortage (including revision in gas supply) while intimating the declared capacity to the SLDC shall not be revised except in case of forced outage of generating unit.

16. Curtailment of scheduled transactions for grid security:

When for the reason of transmission constraints or in the interest of grid security, it becomes inevitable to curtail power flow on a transmission corridor, the transactions already scheduled may be curtailed with immediate effect by the SLDC/RLDC (keeping in view the transaction which is likely to relieve the threat to grid security) as follows:

(i) Transactions under STOA/ T-GNA shall be curtailed first followed by transactions under LTA and MTOA.

(ii) Transactions under STOA/T-GNA shall be curtailed in the following order:

(iii) Within transactions under STOA/T-GNA, bilateral transactions shall be curtailed first followed by collective transactions under day ahead market followed by collective transactions under real time market;

(iv) Within bilateral transactions under STOA/ T-GNA, curtailment shall be done first from generation sources other than wind, solar, wind-solar hybrid and run of the river hydro plants with up to three hours pondage (in case of excess water leading to spillage), pro rata based on their STOA/T-GNA quantum;

(v) The generation from wind, solar, wind-solar hybrid and run of the river hydro plants with up to three hours pondage (in case of excess water leading to spillage) shall be curtailed pro rata based on STOA/T-GNA, after curtailment of generation from other sources, within STOA/T-GNA;

(vi) Collective transactions under day ahead market shall be curtailed after curtailment of bilateral transactions under STOA/T-GNA;

(vii) Collective transactions under real time market shall be curtailed after curtailment of collective transactions under day ahead market.

17. Transactions under LTOA and MTOA shall be curtailed in the following order:

(i) Within transactions under LTOA and MTOA, curtailment shall be done first from generation sources other than wind, solar, wind-solar hybrid and run of the river hydro plants with up to three hours pondage (in case of excess water leading to spillage), on pro-rata basis based on their LTOA and MTOA quantum.

(ii) The generation from wind, solar, wind-solar hybrid and run of the river hydro plants with up to three hours pondage (in case of excess water leading to spillage) shall be curtailed pro rata based on their LTOA and MTOA quantum, after curtailment of generation from other sources, within LTOA and MTOA.

18. After the operating day is over at 24:00 hours, the schedule finally implemented during the day (taking into account all before-the-fact changes in despatch schedule of conventional generating stations and drawal schedule of the Discoms) shall be issued by SLDC. These schedules shall be the datum for commercial accounting.

19. The procedure for final schedules issued by SLDC shall be open to all intra-State entities and other Inter-State open access customer's entities for any checking/verification, for a period of five days. In case any mistake/omission is detected, the SLDC shall forthwith make a complete check and rectify the same.

20. If RLDC curtails a transaction at regional periphery, SLDC shall further incorporate the inter-se curtailment of intra-State entities to implement the curtailment.

21. SLDC shall be responsible for certification of schedules for LTOA, MTOA, STOA intra-State transactions and inter-State transactions of intra-State entities, and actual energy certification of RE Generators on monthly basis as a part of State Energy Account (SEA).

22. Availability declaration of generating station, entitlements, requisitions and schedules shall have resolution up to two decimal/ rounded off to the nearest two decimals at each control area boundary for each of the transactions, to have a resolution of 0.01 in MW and 0.001 in MWh.

23. Implementation of Regulation of Access/Contracts:

SLDC shall implement the regulation of Access/Contracts in accordance with the Late Payment Surcharge (LPS) Rules, 2022, issued by the Central Government, along with any subsequent amendments.

SLDC shall also implement the LPS Procedure and its amendments as approved by NLDC.

Further, any directions or advisories issued by NLDC/RLDC regarding the regulation of Access/Contracts for intra-State entities (buyers/sellers) shall be duly implemented by SLDC.

10.13 Revision of schedules on request of buyers which are GNA grantees:

1. SLDC on behalf of intra-State entities, regional entity ESS' as drawee entities, beneficiaries, regional entity buyers or cross-border buying entities may revise their schedules under GNA as per sub-clauses (1) and (2) of this Regulation in accordance with their respective contracts:
   Provided that scheduled transactions under T-GNA once scheduled cannot be revised other than in case of forced outage as per Regulation 10.13 (3) of these Regulations.
2. Based on the request for revision in schedule made as per sub-clauses (1) of this Regulation, any revision in schedule made in odd time blocks shall become effective from 7th time block and any revision in schedule made in even time blocks shall become effective from 8th time block, counting the time block in which the request for revision has been received by the SLDCs (or RLDC, when RLDC approval is required) to be the first one.
3. Revision of Declared Capacity and schedule, shall be allowed on account of forced outage of a unit of a generating station or ESS (as an injecting entity) only in case of bilateral transactions and not in case of collective transaction. Such generating station or ESS (as injecting entity) or the electricity trader or any other agency selling power from the unit of the generating station or ESS shall immediately intimate the outage of the unit along with the requisition for revision of Declared Capacity and schedule and the estimated time of restoration of the unit, to SLDC or RLDC, as the case may be. The schedule of beneficiaries, sellers and buyers of power from this generating unit shall be revised on pro-rata basis for all bilateral transactions. The revised Declared Capacity and schedules shall become effective from the time block and in the manner as specified in Regulation 10.13 of these Regulations:
   Provided that the generating station or ESS (as injecting entity) or trading licensee or any other agency selling power from a generating station or unit(s) thereof or ESS may revise its estimated restoration time once in a day and the revised schedule shall become effective from the 7th time block or 8th time block as per Regulation 10.15 of these Regulations, counting the time block in which the revision is informed by the generator or ESS to be the first one:

Provided further that the SLDC or the RLDC as the case may be, shall inform the revised schedule to the seller and the buyer. The original schedule shall become effective from the estimated time of restoration of the unit.

10.14 Event of Forced Outage

In the event of forced outage of a generating station or unit thereof, the generating company owning the generating station or unit thereof shall fulfil its supply obligation to the beneficiaries, which made requisition from such generating station or unit thereof:

(i) by entering into contract(s) covered under Power Market Regulations as amended from time to time or
(ii) by arranging supply from any other generating station or unit thereof owned by such generating company subject to honouring of rights of the original beneficiaries of the said generating station or unit thereof from which the supply is arranged or
(iii) through SCED, as applicable.

10.15 Energy Metering and Accounting:

(i) The STU shall be responsible for providing Interface Energy Meters (IEMs) specifications, list of approved vendors, serial number for installation, at all the InSTS interface points, points of connections between the Intra-State entities with grid and other identified points for recording of actual active and reactive energy interchanged in each time-block through those points, and its operation and periodic calibration shall be done by the respective entity. STU shall coordinate for replacement of faulty meters, if any.
(ii) The installation, operation, calibration and maintenance of Interface Energy Meters (IEMs) with automatic remote meter reading (AMR) facility shall be in accordance with the CEA Metering Regulations, 2006 as amended from time to time.
(iii) The time synchronization of metering system shall be through Global Positioning System with counter check from the State Energy Accounting Centre at SLDC.
(iv) The installation, operation, and maintenance of additional communication links, if any, required for the purpose of AMR facility shall be in accordance with CEA Communications Regulations as amended from time to time.

(v) Access to such metering data to the SLDC shall be in accordance with the CEA Metering Regulations 2006 as amended from time to time.

(vi) Entities in whose premises and/or ownership the IEMs are installed shall be responsible for (i) monitoring the healthiness of the CT and PT inputs to the meters, (ii) taking weekly meter readings for the seven (7) day period ending on the preceding Sunday 24:00 hrs and transmitting them to the SLDC by Tuesday noon, in case such readings have not been transmitted through automatic remote meter reading (AMR) facility, (iii) monitoring and ensuring that the time drift of IEM is within the limits as specified in CEA Metering Regulations 2006 as amended from time to time, (iv) promptly intimating the changes in CT and PT ratio and failure of CT and PT to SLDC, and (v) prior intimation regarding periodic testing of IEMs to SLDC:

Provided that in case of any dispute / ambiguity for communication of IEM data, SLDC decision will be final in regard to which entity is responsible to send data to SLDC.

(vii) SLDC shall, based on the IEM readings, compute time block wise actual net injection and drawal of intra-State entities:

Provided that the computations done by SLDC shall be open to all intra-State entities/QCA for a period of fifteen (15) days for checking and verification.

(viii) In case any error or omission is detected by self-analysis or brought to notice by an entity, SLDC, as the case may be, shall make a complete check and rectify the error and revise deviation account accordingly.

(ix) STU shall register all the interface points and interface meters in the MDAS software and share the meter data with SLDC registry for DSM computation. No change in the interface metering infrastructure shall be carried out by STU without prior approval of the SLDC and in case of any change, the same shall be suitably modified in the records of the registry in the MDAS software.

10.16 Reactive Power and Voltage Control:

1. Reactive power compensation should ideally be provided locally, by generating reactive power as close to the reactive power consumption as possible. The State entities are therefore expected to provide local Var compensation or generation such that they do not draw VARs from the State grid, particularly under low-voltage condition. To discourage VAr drawals by State entities, VAr exchanges with InSTS shall be priced as follows:
   (i) The State entity pays for VAr drawal when voltage is below 97%
   (ii) The State entity gets paid for VAr return when voltage is below 97%.

(iii) The State entity gets paid for VAr drawal when voltage is above103%.
(iv) The State entity pays for VAr return when voltage is above 103%

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

2. The charge for VArs shall be at a rate prescribed under IEGC from time to time.
3. All the Inverter Based Resources (IBRs) covering wind, solar and energy storage shall ensure that they have the necessary capability, as per CEA Connectivity Standards, all the time including non-operating hours and night hours for solar.
4. For IBRs capacity not coming directly to the point of interconnection but through the pooling station, the Power Park Developer/ Project developer / Lead generator / QCA, as the case may be, shall act as aggregator for the Reactive Energy Charges for payments to and from the Pool Account at SLDC level. The de-pooling of Reactive Energy charges amongst the individual projects shall be the done by the concerned entity.
5. Notwithstanding the above, SLDC may direct a beneficiary to curtail its VAr drawal/injection in case the security of grid or safety of any equipment is endangered.
6. In general, the beneficiaries shall endeavour to minimize the VAr drawal at an interchange point when the voltage at that point is below 95% of the rated voltage and shall not return VAr when the voltage is above 105%. Transformer taps at the respective drawal points may be changed to control the VAr interchange as per the beneficiary's request to SLDC, but only at reasonable intervals. A beneficiary may also request the SLDC for increase/decrease of VAr generation at a generating station for addressing a voltage problem.
7. Switching in/out of all bus and line reactors throughout the State grid shall be carried out as per instructions of SLDC. Tap changing on all transformers in STU system shall also be done as per SLDCs instructions only.
8. The generating station shall change generator-transformer taps and generate/absorb Reactive Power as per instructions of SLDC, within capability limits of the respective generating units; that is without sacrificing the active generation required at that time. SLDC will prepare and publish Intra-State Reactive energy account in line with the CERC with State specific issue if any with approval of the Commission.

10.17 Inspection of Records:

The operational logs and records of the Generating Stations and licensees shall be available for inspection and review by the SLDC.

10.18 Complementary Commercial Mechanisms:

1. The beneficiaries shall pay to the respective generating stations, capacity charges corresponding to plant availability and energy charges for the scheduled despatch, as per the relevant Regulations and Orders of the Commission. The bills for these charges shall be issued by the respective generating station to each beneficiary on a monthly basis.
2. The sum of the above two charges from all beneficiaries shall fully reimburse the generating station for generation according to the given despatch schedule. The deviation from the despatch schedule by generators shall be governed as per the order of the Commission approving the deviation mechanism from time to time.
3. The summation of station-wise ex-power plant despatch schedules from each generating station and any bilaterally agreed interchanges of each beneficiary shall be adjusted for transmission losses, and the net drawal schedule so calculated shall be compared with the actual net drawal of the beneficiary. The deviation from net drawal schedule shall be governed as per the order of the Commission approving the deviation mechanism from time to time.
4. Monthly energy accounts and weekly statement of deviation charges shall be prepared by the SLDC. The weekly statement of deviation charges shall be issued to all constituents by Thursday for the seven-day period ending on the penultimate Sunday at midnight. Payment of deviation charges shall have a high priority and the concerned constituents shall pay the indicated amounts within 7 (seven) days of the statement issue into a State deviation pool account operated by the SLDC. The agencies that have to receive the money on account of deviation charges would then be paid out from the State deviation pool account, within three (3) working days after received the amount on proportion basis.
5. The SLDC shall also issue the weekly statement for VAr charges, to all constituents who have a net drawal / injection of Reactive Energy under low/high voltage conditions. These payments shall also have a high priority and the concerned constituents shall pay the indicated amounts into the State reactive account operated by the SLDC within 7 (seven) days of statement issue. The constituents who have to receive the money because of VAr charges would then be paid out from the State reactive account, within three (3) working days after receiving the amount on proportion basis.
6. If payments against the above deviation /VAr charges are delayed beyond 7 (seven) days from due date of statement, the defaulting constituent shall have

to pay simple interest @ 0.04% for each day of delay. The interest so collected shall be paid to the constituents who had to receive the amount, payment of which got delayed. Persistent payment defaults, if any, shall be reported by the SLDC to the Commission, for initiating remedial action.

7. The money remaining in the State reactive account after pay-out of all VAr charges up to 31st March of every year shall be utilized for training of the SLDC operators, and other similar purposes, which would help in improving/streamlining the operation of the State grid with prior approval of the Commission.
8. In case the voltage profile of the State grid improves to an extent that the total pay-out from the State VAr charges account for a week exceeds the total amount being paid-in for that week, the pay-outs shall be proportionately reduced according to the total amount being paid-in. For Regional reactive charges payable by the State, payment shall be done from Reactive reserve amount and if the State reactive account has no balance or if it is inadequate to meet the gap, shortfall amount shall be apportioned to beneficiaries on the basis of active energy drawal of same week.
9. The SLDC shall prepare the complete statement of the State deviation account and the state Reactive Energy account, on a quarterly basis and circulate the same to all the pool members for verification.
10. All 15-minute energy figures (net scheduled, actually metered and DSM) shall be rounded off to the nearest 0.001 MWh (up to three decimals)
11. Complementary Commercial Mechanism for RE generators (wind, Solar, Hybrid) shall be according to the GERC (Forecasting, Scheduling, Deviation Settlement and Related Matters of Solar and Wind Generation Sources) Regulations, 2019, and as amended from time to time.

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11 Safety

11.1 Control Persons and their Responsibility

1. STU/ Transmission Licensee and all the Users shall nominate suitably authorized persons to be responsible for the co-ordination of safety across their boundary. These persons shall be referred to as Control Persons.

2. STU/ Transmission Licensee shall issue a list of Control Persons with their names, designations, addresses and telephone numbers, to all the Users having direct control boundary with it. This list shall be updated promptly whenever there is any change of name, designation or telephone number of any Control Person named in the list.

3. All Users having a direct control boundary with STU/ Transmission Licensee shall issue a similar list of their Control Persons to STU/ Transmission Licensee. This list shall be updated promptly whenever there is any change of name, designation or telephone number of any Control Person named in the list.

4. Whenever any work across a cross boundary is to be carried out by the user or STU/ Transmission Licensee, the Control Person of the user or STU/ Transmission Licensee as the case may be, who has to carry out the work, shall directly contact his counterpart. Code words shall be agreed to, at the time of work, to ensure correct identification ofboth the parties. Contact between Control Persons shall normally be made by direct telephone.

5. If the work extends beyond one shift, the Control Person shall hand over charge to the relief Control Person and fully brief him on the nature of work and the code words in the operation.

6. The Control Persons shall cooperate to establish and maintain the precautions necessary to be taken for carrying out the required work in a safe manner. Both, the established isolation and the established earth, shall be kept in the locked positions wherever such facilities exist, and these shall be clearly identified and entered into the log sheet.

7. The Control Person in charge of the work shall satisfy himself that all the safety precautions to be taken are established before commencing the work. He should issue the safety documentation to the working party to allow the work to commence.

8. After completion of the work, the Control Person in charge of the work being carried out, should satisfy himself that the safety precautions taken are no longer required, and shall make a direct contact with his counterpart Control Person and request removal of the safety precautions.

   The equipment shall be declared as suitable for return to service only after confirmation of removal of all the safety precautions, by direct communication, using the code word contact between the two Control Persons, and the return of agreed safety documentation from the working party.

9. STU / Transmission licensees shall develop an agreed written procedure for Cross Boundary Safety and continuously update the same.

10. Any dispute concerning Cross Boundary Safety shall be resolved at the level of STU, if STU is not a party. In case where STU is a party, the dispute shall be referred to the Commission for resolution.

11.2 Special Considerations

1. All Users shall comply with the agreed safety rules drawn up in accordance with Central Electricity Authority (Measures Relating to Safety and Electric Supply) Regulations, 2023 as amended from time to time.

2. All the equipment on Cross Boundary Circuits, which may be used for the purpose of safety coordination and establishment of isolation and earthing, shall be permanently and clearly marked with an identification number or name being unique to the particular substation. The equipment shall be regularly inspected and maintained in accordance with the manufacturer's specifications.

3. Each Control Person shall maintain a legibly written safety log, in chronological order, ofall operations and messages relating to the safety coordination sent and received by him. All these safety logs shall be retained for a period of not less than ten years.

4. Each of the Distribution Licensees connected to the Transmission System shall maintain an updated map of his system pertaining to the area fed by each substation, and exhibit the same in the concerned area offices of the Distribution Licensee.

11.3 Safety and Line Clear Permits

Introduction

This section sets out the procedure for the record of the Line Clear Permit and sets guidelines for ensuring safety from electrical hazards to consumers, general public and working personnel.

Objective

The main objective of this section is to ensure safety to the working personnel of STU/ Transmission Licensee and Users and maintenance of proper records for the issue of Line Clear Permits for allowing working personnel to carry out the works.

11.3.1 Safety Standards

1. The Safety Standard issued separately formulates the precautions to be taken for ensuring safety of the general public, consumers of electricity and the workmen. This forms an integral part of the Grid Code and STU/ Transmission Licensee and all the Users shall comply with this standard.

2. STU/ Transmission Licensee shall prepare its own safety manual for the Transmission Lines, substations based on this standard. For the guidance of the shift operators, Operation and Maintenance Manuals for each substation shall be prepared by the Licensee. These manuals shall contain all the maintenance and operation schedules,based on the recommendations of the manufacturers of the various equipment installed in the substation. These manuals shall be periodically reviewed based on the experience gained and replacement of equipment. A maintenance register for the equipment including the station batteries shall be maintained at the respective substations. These shall be updated as and when the maintenance work is carried out and shall be periodically reviewed by the appropriate higher authority in whose control the substation falls. Similar registers shall be maintained for the Transmission Lines.

3. The Operation Manual shall clearly contain the details of isolation and earthing to be provided for allowing work on the equipment. The Single Line Diagram of the substation indicating the positions of various isolating devices shall be prominentlydisplayed in the station. Charts showing the clearances from live parts (section clearance)for working on the isolated equipment where workmen are allowed to work shall be displayed prominently at each substation.

4. The danger boards as stipulated in the Central Electricity Authority (Measures Relating to Safety and Electric Supply) Regulations, 2023 as amended from time to time and in relevant Indian Standards shall be displayed at the places approachable by the general public.

5. Regular maintenance shall be carried out on all the Transmission Lines in accordance with IS:5613 and records of all these shall be maintained. Wherever possible, hot line checking and replacement of failed insulators shall be made before and after the monsoon.

6. All the equipment in the receiving stations and substations shall be maintained in good condition as per the manufacturers' manuals and relevant Indian and/or international standards wherever available. The relays and circuit breakers shall be checked for their proper operations whenever these are taken out for maintenance purposes. The station batteries shall be maintained in good working condition by carrying out routine checks and maintenance works. The DC system provided in all these stations shall be properly maintained with no appreciable leakage current. An online monitoring system for monitoring of leakage and detection of ground faults shall be provided.

11.3.2 Line Clear Permit (LCP)

The format under Annexure 5, 6 and 7 shall be used. The form under Annexure-5 and designated as requisition for Line Clear Permit shall be used by the requesting safety coordinator, who is an authorized person. The form under Annexure-6 and designated as check list for Line Clear Permit shall be used at the time of issue of Line Clear Permit. The form under Annexure-7 and designated as Line Clear Return shall be used for the return of the Line Clear Permit after the work for which the Line Clear Permit was taken, is completed.

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12 Communication and Data Acquisition

12.1 Remote Terminal Unit (RTU)/Substation Automation System (SAS)/PLCs

"Remote Terminal Units" (RTU) / Substation Automation System (SAS) is the device suitable for measuring, recording and storing the consumption of electricity or any other quantity related with electrical system and status of the equipment on real time basis and exchanging such information with the data acquisition system for display and control.

The RTU/SAS System /device should communicate with Control Centre front end system in either IEC-60870-5-101 or IEC-60870-5-104 protocol.

(i) IEC - 101 works on serial communication between site and control centre and requires serial interface. Different Physical interface that can be used for 101 communications are RS-232 / RS 422 / RS 485.

(ii) IEC 104 works on TCP/IP based communication and it can use following Physical interface, i.e., Ethernet (IEEE 802.3 / IEEE 802.3u).

The communication interface equipment at the remote (RTU/SAS) location shall support the interfaces as mentioned above and the communication provider shall ensure the proposed data sharing protocol by the stations so that the compatible interface is provided.

12.2 Phasor Measurement Unit

PMU (Phasor Measurement Unit) provides phasor information (both magnitude and phase angle) for one or more phases of AC voltage or current waveforms including positive sequence phasors and analog quantities like MW, MVAR, frequency, Rate of Change of Frequency (ROCOF) in real time.

Control Centre shall exchange phasor information between their respective Synchro phasor systems via high-speed real-time data acquisition networks, using the protocol specified in latest IEEE C37.118 communication standard preferably.

PMU shall report on C37.118 2011 or higher protocol with configuration Frame 3 or better for data communications. Different Physical Interface for PMU includes Ethernet (IEEE 802.3 / IEEE 802.3u).

All data items, regardless of type, are generally collected and disseminated at a

frequency of 25 samples per second (can be higher rate of samples per second in future) and should be sent to Control Centre with the associated data quality codes in compliance with latest IEEE C37.118 communication standards.

12.3 Communication

1. Independent dedicated communication links for voice communication, written communication and data acquisition shall be installed and maintained by STU/ Transmission Licensee between all the generating stations, receiving stations, substations and SLDC / sub-SLDC. In addition, similar links between adjacent transmission system substations shall also be established. Other means of reliable communication systems shall also be established to ensure safe and secure grid operations.

2. Communication shall be available by direct dialing of discrete numbers and also throughhotline by just lifting the telephone handset. Hotline links shall also be established by STU between all major generating stations, important substations and SLDC.

3. The various types of Interfaces required in communication equipment at Remote Station and Control Centre shall be governed in accordance with Schedule II of CEA (Technical Standards for Communication System in Power System Operations) Regulations, 2020 as amended from time to time, as applicable.

12.4 Data Acquisition

1. The following real time data are required by SLDC for effective control of the power system:

Table 10: Details of Real Time Data required by SLDC

Sl. No.	Description	Analog Points	Digital Points	Protection Signal
1	Line	-MW -MVAR	- line Isolator Status SOE with Time Stamping	Main1/Main2 protection, Over Voltage protection, LBB

Sl. No.	Description	Analog Points	Digital Points	Protection Signal
2	Bays		- Breaker -Isolator/ Disconnector (Line Selection in DMT scheme) SOE with Time Stamping	
3	Main Buses, Transfer Bus, Bus Coupler, Bus Sectionalizer	-Voltage -Frequency -MW & MVAR flow in case of bus sectionalizer -MW& MVAR flow across Bus Couplers	- Breaker, Isolator, SOE with time stamp	Main1/Main2 protection
4	Transformer	-MW/MVAR for HV / LV side -Tap Position	-Breaker -Isolator Status SOE with Time Stamping	Main1/Main2 protection
5	(Hot standby) Transformer	-MW/MVAR for HV / LV side	-Breaker -Isolator Status	
6	Reactor	MVAR	-Breaker -Isolator Status --Bypass isolator status of NGR -SOE with Time Stamping	Main 1 and 2 Protection
	(Hot standby) Spare Reactor	MVAR	-Breaker -Isolator Status	
7	FSC/TCSC	-% compensation	-Bypass Breaker -Bypass Isolator -FSC ON/OFF Status SOE with Time Stamping	Oscillation Damping Controller (Operated or not) status

Sl. No.	Description	Analog Points	Digital Points	Protection Signal
8	SVC	-Slope -Gain -Q-Ref -V-Ref -V min -Vmax -Current for each branch -total M VAR compensation	-Isolator Status for each branch with SOE -SVC Mode (Automatic/Manual) -Q Control Mode (Enable/Disable) SOE with Time Stamping	Oscillation Damping Controller (Operated or not) status
9	HVDC (Both Type: Line Commutate Converter & Voltage Source Converter)	-DC Voltage -DC Power Flow -DC Current -Individual Filter MVAR -Firing Angle-Alpha -Extinction angle-Gamma, etc. -Power order, set point Compensation settings if applicable	-Individual Filter Status -HVDC Mode (Metallic return / Ground return) -Isolator/CB Status of DC Switchyard -RPC Status -Run back Status -POD Status -SSDC Status - SOE with Time Stamping -DMR -1 status -DMR-2 status -MRTB status -GRTB status -SoE for HVDC auto-restart	DC line Fault Protection, ESOF (emergency Switch Off) and HVDC Pole Block protection, POD Status (operated or not

Sl. No.	Description	Analog Points	Digital Points	Protection Signal
10	Converter Transformer	-MW/MVAR for HV/LV Side -Tap Position	-Breaker -Isolator Status	
11	Spare Converter transformer	-MW/MVAI HV/LV Si	-Breaker -Isolator Status	
12	Generator	-MW (HV/LV) -MVAR (HV/LV) -LV Voltage / Frequency Unit Set point -Unit DeltaP for AGC,	RGMO/FGMO ON/OFF Status - LV Breaker Status - AGC Local / Remote status - PSS ON/OFF status	Class A, B, C protection status
		-Droop settings Value, -AVR Reference Voltage	- AVR ON/OFF Status SOE with Time Stamping	
13	Generator Transformer	-MW/MVAR for HV/LV Side -Tap Position	-Breaker -Isolator Status	Main1/Main2 protection
14	Synchronous Condenser	-MW (HV/LV) -MVAR (HV/LV) -LV Voltage / Frequency	-Breaker -Isolator Status	
15	STATCOM	Qstat, QMSC, QMSR, VHV, VMV, Qtra , Paux, Qaux, Tap Position of Coupling transformer Power Oscillation damping setting Inductive slope	- CB - Isolator STATCOM modes status (Voltage/Reactive/NSC etc) POD status SOE with Time Stamping	

Sl. No.	Description	Analog Points	Digital Points	Protection Signal
		Capacitive slope Up set reference/ Down set reference Feedback signal voltage MSC/MSR switching in and out setting (voltage, time)		
16	Phase Shifter	MW / MVAR Angle of shift	- CB - Isolator - SoE with time stamping	
17	Wind	- Wind speed at hub height - Wind direction	WTG CB Status	
		- Blade Angle - Ambient air temperature - Relative Humidity (%) - Air Density -Atmospheric Pressure - Total MW/MVAR - Individual Turbine MW, - MVAR, wind speed, Wind direction - Total number of turbines online - Total Power Capacity.	CB and Isolator status of pooling station Turbine Availability PPC modes status (Voltage/PF/Reactive Power) Frequency control (FGMO/RGMO) status	

Sl. No.	Description	Analog Points	Digital Points	Protection Signal
		- Available Power Capacity -Available Power (Active and Reactive) at Plant level. -Active Power set point -Reactive Power set point -PPC modes signals: Reference and actual values of Voltage Control mode, Power Factor Control mode and Reactive Power Control mode) -Droop setting of Voltage Control mode -Active power ramp rate UP and down setting	LVRT/HVRT status	
18	Solar	-Global horizontal irradiance -Global plane of array irradiance - Diffusion Irradiance- Watt per meter square - Direct Irradiance- Watt per meter	- Inverter Status (ON/OFF) -Module Availability -CB/Isolator Status -Rectifier Availability -PPC modes status Voltage/PF/Reactive Power)	

Sl. No.	Description	Analog Points	Digital Points	Protection Signal
		square - Sunrise and Sunset timings -Tilt angle - Dust fall -Ambient temperature (deg C) -Back of PV module temperature -Battery charge -MW/MVAR -Relative Humidity - Performance Ratio - Cloud Cover (Okta)	Frequency control (FGMO/RGMO) status AGC status	
			LVRT/HVRT status	

Sl. No.	Description	Analog Points	Digital Points	Protection Signal
		-Temperature, Wind Speed, Rainfall, Wind Speed, Wind Direction - Inverter MW/MVAR (AC Side & DC Side) -Available Power (Active and Reactive) at Plant level. -Active Power set point -Reactive Power set point -PPC modes signals Reference and actual values of Voltage Control mode, Power Factor Control mode and Reactive Power Control mode) -Droop setting of Voltage Control mode -Active power ramp rate UP and down setting		
19	Energy Storage Resource	State of Charge MW/MVAR (AC Side & DC	CB/Isolator Status Controller status, RGMO/FGMO	

Sl. No.	Description	Analog Points	Digital Points	Protection Signal
		Side) Modes (Energy storage, Frequency regulation, etc.)		
20	SPS Signal		DIGITAL STATUS: Enable/Disable, Operated/No Operated. (Condition/Logic Wise)	
21	Weather Paramete	-Temperature - Wind Speed -Humidity -Rainfall		
22	AGC	-Unit Load Set Point (ULSP) -Actual Generation MW -Unit Capability	-Circuit Breaker Status on/off -Governor status on/off	
		-RGMO/FGMO/Governor input to governor -DeltaP -Reactive Power -AVR Voltage Set Point -Low Voltage (LV) side Actual Voltage -Generator Transformer (GT) Tap Position -Distribution Factor Additional Analog inputs from Hydro	- AGC Local/Remote Additional Digital inputs from Hydro power plants - Pumping Status on/off	

Sl. No.	Description	Analog Points	Digital Points	Protection Signal
		power plants		
		-Minimum load at which unit can stably run after synchronization – Unit wise (P1) (in MW) - Forbidden zones or high cavitation zones - Unit- wise (From MW to MW) - P2 to P3 - Maximum loading possible on unit (continuous) (P4) - Declared Energy for the day - Schedule Energy (Cumulative) - Water gross head (m) Additional Analog inputs from Gas power plants - Reference exhaust gas temperature - Actual exhaust gas temperature		
23	Loads (Lift Irrigation etc.)	- MW/MVAR	-Breaker -Isolator Status	

Table 11: PMU Signal List

Sl. No	Description	Analog Points	Digital Points	Protection Signal
1	Line	VOLTAGE {VRM, VYM, VBM, VPM, VRA, VYA, VBA, VPA} CURRENT {IRM, IYM, IBM, IPM, IRA, IYA, IBA, IPA} MW, MVAR, F , DF/DT	-Main Breaker status -Tie Breaker status -Isolators	Main1/Main 2 protection,
2	Bays		- Breaker -Isolators	
3	Main Buses, Transfer Buses	- VOLTAGE {VRM, VYM, VBM, VPM, VRA, VYA, VBA, VPA} F, DF/DT	Bus Sectionalizer, Bus Coupler Breaker	
4	Transformer/Coupling Transformer/Converter Transformer	- VOLTAGE {VRM, VYM, VBM, VPM, VRA, VYA, VBA, VPA} CURRENT {IRM, IYM, IBM, IPM, IRA, IYA, IBA, IPA} MW/MVAR for HV& LV Side	-Breaker -Isolators	Main1/Main2 protection
5	Reactor	VOLTAGE {VRM, VYM, VBM, VPM, VRA, VYA, VBA, VPA} CURRENT {IRM, IYM, IBM, IPM, IRA, IYA, IBA, IPA} MVAR	-Breaker -Isolators	

6	FSC/TCSC	VOLTAGE {VRM, VYM, VBM, VPM, VRA, VYA, VBA, VPA} CURRENT {IRM, IYM, IBM, IPM, IRA, IYA, IBA, IPA} MVAR	-Bypass Breaker - FSC ON/OFF Status	

7	SVC	VOLTAGE {VRM, VYM, VBM, VPM, VRA, VYA, VBA, VPA} CURRENT {IRM, IYM, IBM, IPM, IRA, IYA, IBA, IPA} MVAR	Breaker	
8	Generator	VOLTAGE {VRM, VYM, VBM, VPM, VRA, VYA, VBA, VPA} CURRENT {IRM, IYM, IBM, IPM, IRA, IYA, IBA, IPA} MW, MVAR, F, DF/DT for HV& LV Side	-RGMO/FGMO ON/OFF Status Breaker Status -Isolators	
9	STATCOM	VOLTAGE {VRM, VYM, VBM, VPM, VRA, VYA, VBA, VPA} CURRENT {IRM, IYM,	- CB OF EACH MODULE MSR, MSC	

		IBM, IPM, IRA, IYA, IBA, IPA} MW, MVAR, F, DF/DT		
10	Phase Shifter	VOLTAGE {VRM, VYM, VBM, VPM, VRA, VYA, VBA, VPA} CURRENT {IRM, IYM, IBM, IPM, IRA, IYA, IBA, IPA} HV & LV MW / MVAR F, DF/DT	- CB	

2. The generating companies shall provide the necessary MFM (Multifunction Meter) for the transmission of the above data from their generating stations to SLDC/WRLDC.

3. STU/ Transmission Licensee shall similarly provide the necessary MFM (Multi Function Meter) for the transmission of the above data from their receiving stations and substations to SLDC/WRLDC.

4. All Users shall establish a suitable data transfer link between Plant/Substation and SLDC/ Sub-SLDC for exchange of operational data transmission.

5. At all the 400 kV lines, 220 kV lines and 132 kV lines disturbance recorders shall be installed and recorder data shall be made available at SLDC for post event analysis of the disturbances.

12.5 Cyber Security

(a) General

This chapter deals with measures to be taken to safeguard the State grid from spyware, malware, cyber-attacks, network hacking, procedures for security audits from time to time, upgradation of system requirements and keeping

abreast of latest developments in the area of cyber-attacks and cyber security requirements,

All Users, SLDC, STU, QCAs, shall have in place, a Cyber Security framework in accordance with Information Technology Act, 2000, CEA Technical Standards for Connectivity Regulations, CEA (Cyber Security in Power Sector) Guidelines, 2021 and any such Regulations issued from time to time, by an appropriate authority to identify the critical cyber assets and protect them so as to support reliable operation of the grid.

All user shall integrate RTU/SAS as per **Annexure-8** with SLDC/Sub-SLDC

(b) Cyber Audit

All Users, SLDC and STU, shall conduct cyber security audit as per the guidelines mentioned in the CEA (Cyber security in power sector) Guidelines, 2021 and any other guidelines issued by an appropriate Authority.

(c) Mechanism of Reporting

(i) All entities shall immediately report to the appropriate government agencies in accordance with Information Technology Act 2000, as amended from time to time and CEA (Cyber security in power sector) Guideline 2021 in case of any cyber attack.

(ii) SLDC and the Commission shall also be informed by such entities in case of any instance of cyber attack

(d) Cyber Security Coordination Forum

(i) The sectoral CERT (Computer Emergency Response Team) for wings of power sector, as notified by Government of India, from time to time, shall form a Cyber Security Coordination Forum with members from all concerned utilities and other statutory agencies to coordinate and deliberate on the cyber security challenges and gaps at appropriate level the regional sub-committee, as the case may be.

(ii) The sectoral CERT shall lay down rules of procedure for carrying out their activities.

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13 Operational Event and Incident/Accident Reporting

13.1 Reportable Incidents

1. All events in the Transmission System having an operational effect on the user's system shall be notified by STU/ Transmission Licensee to SLDC and the Users, whose systems are affected.

2. All events on the user's system having an operational effect on the Transmission System shall be notified by the user to STU/ Transmission Licensee and SLDC who in turn shall notify the other Users on whose system the event may have an operational effect.

3. Typical examples of reportable incidents that could affect the Transmission System are asfollows:

   (a) Exceptionally high/low voltage or frequency,

   (b) Serious equipment problem, i.e., major circuit breaker, transformer, busbar fault,

   (c) Major problem in the generating unit,

   (d) Tripping of ICT, Transmission Line or Capacitor Bank,

   (e) Major fire incident, cyclones, storms, earthquakes etc.

   (f) Major protection failure,

   (g) Overloading of equipment or transmission line which may result in hazard to the personnel,

   (h) Activation of any alarm or indication of abnormal operating condition,

   (i) Adverse climatic conditions being experienced or forecast,

   (j) Breakdown, or faults, or temporary changes in the capabilities of plant and/or apparatus,

   (k) Impending risks of protection operation,

   (l) Loss of load,

   (m) Accidents,

(n) Excessive drawal deviations,

(o) Minor equipment alarms.

The last two reportable incidents are typical examples of events of less consequence, but still affect the Transmission System and can be reasonably classified as minor. They require corrective action, but do not require immediate reporting to management but they should be reported at later stage within reasonable time.

4. The examples indicated in the above Regulation 13.1.3 are only illustrative and in no way, limit the general requirements to be reported.

13.2 Reporting Procedure

1. All reportable incidents occurring in lines and equipment of 132 kV and above at the grid substations shall promptly be reported orally by the user whose equipment has experienced the incident to all other significantly affected Users and SLDC. The reportinguser should submit a written confirmation to SLDC within one hour of such an oralreport. If the incident is major in nature, the written report may be submitted within two hours, duly followed by a comprehensive report within 48 hours of the submission of the initial written report. In other cases, the reporting user shall submit a report within five working days to SLDC.

2. The SLDC shall call for a report from any user on any reportable incident affecting other Users, in case such a user whose equipment might have been a source of the reportable incident does not report the same. However, this shall not relieve any user from the obligation to report events in accordance with the Intimation of Accidents (Form and Time of Service of Notice) Rules, 2005 notified by the Central Government. The format for such a report shall be as per the approval of the STU and typicallycontain the following:

(a) Location of the incident,

(b) Date and time of the incident,

(c) Plant or equipment involved,

(d) Supplies interrupted and the duration wherever applicable,

(e) Amount of generation lost, wherever applicable,

(f) System parameters before and after the incident, (voltage, frequency, flows,generation etc.)

(g) Network configuration before the incident,

(h) Relay indications and performance of protection,

(i) Brief description of the incident,

(j) Estimated time of return to service,

(k) Any other relevant information,

(l) Recommendations for future improvement,

(m) Single line diagram

(n) Possibility of alternate arrangement of supply

(o) All relevant system data including copies of records of all recording instruments including Disturbance Recorder, Event Logger, Data Acquisition System (DAS), etc.,

(p) Name and designation of reporting officer.

3. The report shall contain sufficient detail to describe the event to enable the recipient to assess the implications and risks arising out of the same. The cause need not be included in the report, but the recipient may ask for clarifications wherever necessary and it is obligatory that the reporting user shall put his best efforts and provide all the necessary and reasonable information.

4. In case of a request by either party, the oral report shall be written down by the sender and dictated by way of a telephone message or sent by fax/e-mail to the recipient. In case of an emergency, the report can be given orally, followed by written confirmation.

5. The maximum time limit allowed for an oral report of the event is fifteen minutes from the time of the occurrence of the event.

6. SLDC will be responsible for reporting the event in line with the procedure set in IEGC.

13.3 Significant Events

1. A significant event includes events having an operational effect; e.g.

   (a) Tripping of plant and/or apparatus manually or automatically,

   (b) Voltage outside statutory limits,

   (c) System frequency outside statutory limits,

   (d) System instability,

   (e) System overloads.

2. Wherever a user reports an event, which the SLDC or STU/ Transmission Licensee considers to have had a significant effect on the Transmission System, the STU/ Transmission Licensee may require the user to report that event in writing within one day.

3. Wherever STU/ Transmission Licensee notifies SLDC and a user of any event which the user or SLDC considers to have had a significant effect on the user's system, the usermay require the Transmission Licensee to report that event in writing within one day.

13.4 Warnings

1. An oral warning shall be issued by SLDC and confirmed in writing as well, to the STU/ Transmission Licensee and the Users, who may be affected, when SLDC knows that there is a risk of widespread and serious disturbance to the whole, or part of the total system.

2. Provided that sufficient time is available, the warning shall contain such information as the SLDC considers reasonable, to explain the nature, extent of the anticipated disturbance, to the user and STU/ Transmission Licensee, provided that such information is available to SLDC.

3. Each user and STU/ Transmission Licensee, on receipt of such a warning, shall take necessary steps to warn its operational staff and maintain its plant and apparatus in the condition in which it is best able to withstand the anticipated disturbance for the duration of the warning.

4. Scheduling and despatch may be affected during the period covered by such a warning.

13.5 Loss of communication with SLDC

1. In the event of loss of communication with SLDC, the provision made as above shall not apply; instead, the following provision shall apply.

2. Each generating station shall continue to operate in accordance with the last despatch instruction issued by SLDC, but shall use all reasonable endeavours to maintain the system frequency at the target of 50 Hz, plus or minus 0.5 Hz by monitoring frequency, until such time the new despatch instructions are received from SLDC.

13.6 Major Failure

Whenever a major failure takes place, STU/ Transmission Licensee and other Users shall cooperate, inquire and establish the cause of the failure and produce appropriate recommendations. The STU shall submit the inquiry report with the recommendations to the Commission within two months of the incident.

13.7 Accident Reporting

If any accident occurs in connection with the generation, transmission, distribution supply or use of electricity or in connection with any part of electric lines or electrical plant of any person and the accident results or is likely to have resulted in loss of human or animal life or any injury to a human being or animal, the same shall be dealt with, in accordance with procedures laid down in the Power System Safety Standard.

13.8 Performance/ Operational Reporting

1. Every Discom / Licensee has to submit a quarterly performance report covering Demand Management (DM), Reactive Power Management and system operation, pocket-wiseload forecasting details quarterly to GERC/ STU.

2. Similarly, every generator also has to submit performance report in terms of PLF, other Key Performance Indicators, including range of maximum and minimum VAR injection and VAR absorption within capability curve, every half-yearly, to GERC and the STUs.

3. The STU has to submit operational / performance and planning of network development every six month to GERC, DISCOMs.

4. Similarly, SLDC has to submit operation/ performance report on grid stability and security, every half-yearly to GERC, STU, DISCOMs and licensee.

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14 Monitoring and Compliance Code

14.1 Assessment of Compliances

The performance of all Users, STU, QCA, SLDC, and Intra-State Generating Station with respect to compliance of these Regulations shall be assessed periodically.

14.2 Monitoring of Compliance

1. In order to ensure compliance, two methodologies shall be followed:
   I. Self-Audit
   II. Compliance Audit

I. Self - Audit:

a. All Users, STU, SLDC, QCAs, and Intra-State Generating Station shall conduct annual self-audits to review compliance of these Regulations and submit the reports by 31st July of every year.

b. The self-audit report shall inter-alia contain the following information with respect to non-compliance:
   (i) Sufficient information to understand how and why the non-compliance occurred;
   (ii) Extent of damage caused by such non-compliance;
   (iii) Steps and timeline planned to rectify the same;
   (iv) Steps taken to mitigate any future recurrence;

c. The self-audit reports by Users and QCAs, shall be submitted to SLDC.

d. The self-audit report of SLDC and STUs shall be submitted to the Commission.

e. The deficiencies shall be rectified in a time bound manner within a reasonable time.

f. In the State control area, the monitoring agency for Users shall be the SLDC. The monitoring agency shall track the progress of compliances of Users, and exceptional reporting for non-compliance shall be submitted to the Commission.

g. The monitoring agency for STU and SLDC shall be the Commission.

h. The STU shall also continuously monitor the instances of non-compliance of the provisions of these Regulations and endeavour to sort out all operational issues and deliberate on the ways in which such cases of non-compliance shall be prevented in future. The STU may also report any unresolved issues to the Commission.

i. The Commission may initiate appropriate proceedings upon receipt of report under sub-clauses (e) and (g) of this Regulation.

j. In case of non-compliance of any provisions of these Regulations by SLDC, STU, Intra-State Generating Station, Users and any other person, the matter

may be reported by any person to the Commission through filing of a Petition.

II. Independent Third-Party Compliance Audit:

The Commission may order independent third-party compliance audit for any User, QCA, STU and SLDC as deemed necessary based on the facts brought to the knowledge of the Commission.

14.3 Non-Compliance

1) If a User fails to comply with the provision(s) of these Regulations, the affected party shall inform the SLDC for taking immediate remedial measures as per provisions of these Regulations.

2) In case of default of these Regulations without prejudice to other actions as may be taken by SLDC, the SLDC may file a Petition before the Commission.

3) Notwithstanding anything contained in these Regulations, the Commission, if satisfied, may also take Suo-motu action against any person, in case of non-compliance of any of the provisions of these Regulations comes to its notice.

4) Wrong declaration of capacity, non-compliance of SLDC‟s instructions, non-compliance of SLDC's instructions for backing down without adequate reasons, non-furnishing data, etc. shall constitute non-compliance of the Grid Code and shall be subject to financial penalty as may be decided by the Commission.

5) In case of persistent non-compliance of the provisions of the Grid Code and/ or with the procedures developed under such provisions, such matter shall be reported to the Commission by SLDC. Consistent failure to comply with the Grid Code may lead to disconnection of the User's plant and/or facilities.

6) SLDC may give such directions and exercise such supervision and control as may be required for ensuring the integrated grid operations and for achieving the maximum economy and efficiency in the operation of power system in the State.

7) Every Transmission Licensee and User connected with the operation of the power system shall comply with the directions issued by the State Load Despatch Centre.

8) If any dispute arises with reference to the quality of electricity or safe, secure and integrated operation of the State grid or in relation to any direction given under the provisions of the Gujarat Electricity Grid Code, it shall be referred to the Commission by SLDC for decision:

   Provided that till the time the decision of the Commission is pending, the direction of the SLDC shall be complied with by the Transmission Licensee or User.

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15 Miscellaneous

15.1 Review and Revisions

Users seeking any amendment to the Grid Code shall send written requests to the STU with a copy to the Commission. STU shall examine the proposed changes / modifications in line with IEGC. Whenever, it is observed that a certain Regulation of the Grid Code is not consistent with the IEGC, then STU will inform the Commission for amendments.

15.2 Power to Relax

The Commission, for reasons to be recorded in writing, may relax any of the provisions of these Regulations on its own motion or on an application made before it by an affected person to remove the hardship arising out of the operation of these Regulations, applicable to a class of persons.

15.3 Power to remove difficulty

If any difficulty arises in giving effect to the provisions of these Regulations, the Commission may, on its own motion or on an application made before it by the nodal agency, by order, make such provisions not inconsistent with the provisions of the Act or provisions of other Regulations specified by the Commission, as may appear to be necessary for removing the difficulty in giving effect to the objectives of these Regulations.

15.4 Repeal and Savings

1. Save as otherwise provided in these Regulations, the Gujarat Electricity Regulatory Commission (Gujarat Electricity Grid Code) Regulations, 2013 and all subsequent amendments there of shall stand repealed from the date of commencement of these Regulations.

2. Notwithstanding such repeal, anything done or any action taken or purported to have been done or taken including any procedure, minutes, reports, confirmation or declaration of any instrument executed under the repealed Regulations shall be deemed to have been done or taken under the relevant provisions of these Regulations.

3. Nothing in this Grid Code shall be deemed to limit or otherwise affect the inherent

powers of the Commission to make such orders as may be necessary for ends of justice or to prevent abuse of the process of law.

4. Nothing in this Grid Code shall bar the Commission from adopting, in conformity with the provisions of the Act, a procedure which is at variance with any of the provisions of this Grid Code, if the Commission, in view of the special circumstances of a matter or class of matters and for reasons to be recorded in writing, deems it necessary or expedient for dealing with such a matter or class of matters.

5. Nothing in this Grid Code shall, expressly or impliedly, bar the Commission dealing with any matter or exercising any power under the Act for which no Regulations have been framed and the Commission may deal with such matters, power and functions in a manner it thinks fit.

15.5 Issue of Suo-motu orders and Directions

The Commission may from time-to-time issue Suo-motu orders and practice directions with regard to implementation of these Regulations and matters incidental or ancillary thereto, as the case may be.

15.6 Treatment of these Regulations in Contract

Unless specifically provided for, the provisions of these Regulations or any amendments thereof shall not be treated under 'Change in law' in any of the agreements entered into by any of the Users covered under these Regulations.

Sd/-
RANJEETH KUMAR J., IAS
Secretary
Gujarat Electricity Regulatory Commission
Gandhinagar, Gujarat

Place: Gandhinagar
Date: 14.05.2026

ANNEXURE-1

Planning Data Requirement from the Generating and Distribution Company

Part- I - Generation

(To be furnished by the generating company to STU)

1 Standard Planning Data (Generation)

1.1 Thermal

(I). General:

1. Site	Furnish location map (schematic) showing roads, railway lines, transmission lines, rivers, andreservoirs, if any.
2.Approximate period of Construction	
3. Annual generation in million kWH	

(II) Connection:

1. Connection Point / Interface Point	Furnish single line diagram of the proposed connection with the Transmission System with clearindication of possibility for right-of-way for unobstructed outlet
2. Step up voltage for connection kV	

(III) Station Capacity:

1. Total generating station capacity (MW)	
2.No. of units and unit size MW	State whether development will be carried out in phases and if so, furnish details

(IV) Generating Unit Data:

1. Generator	

(a) Make and Type	
(b) Rating (MVA)	
(c)Terminal Voltage (kV)	
(d)Rated Power Factor	
(e) Reactive Power capability (MVAr) in the range 0.95 leading and 0.85 lagging	
(f) Short Circuit Ratio	
(g)Direct axis transient reactance (% on MVA rating)	
(h)Direct axis sub-transient reactance (% on MVA rating)	
(i) Auxiliary Power Requirement	
2. Generator Transformer	
(a) Type	
(b) Rated Capacity (MVA)	
(c)Voltage Ratio (HV/LV)	
(d) Tap change range (+% to - %)	
(e) Percentage Impedance (Positive Sequence at Full load).	

1.2 Hydro Electric

(i) General:

(as applicable to thermal generating stations mentioned above)

(ii) Connection:

(as applicable to thermal generating stations mentioned above)

(iii) Station Capacity

(as applicable to thermal generating stations mentioned above)

(iv) Generation Unit Data:

(as applicable to thermal generating stations mentioned above)

2 Detailed Planning Data (Generation)

2.1 Thermal Generating Stations

I. General:

1. Name of generating station

2. No. and capacity of generating units (MW)

3. Single line diagram of generating station and switchyard

4. Relaying and metering diagram

5. Neutral grounding of generating units

6. Excitation control

7. Earthing arrangements with earth resistance values

8. Communication- details of PLCC and other communication equipment installed

II. Protection and Metering:

1. Full description including settings for all relays and protection systems installed on the generating unit, generating unit transformer, auxiliary transformer and electrical motor ofmajor equipment; viz. boiler feed pump, ID fans, condensate extraction pump etc.

2. Full description including settings for all relays installed on all outgoing feeders from generating station switchyard, tie circuit breakers, incoming circuit breakers.

3. Full description of inter-tripping of circuit breakers at Connection Point(s) /Interface Point(s) with the Transmission System

4. Most probable fault clearance time for electrical faults on the user's system

5. Full description of operational and commercial metering schemes

6. Breaker operating time counting from initiation of protective relay to the opening of breaker

III. Switchyard:

1. In relation to Interconnecting Transformers between EHV / HV Transmission System andthe Generator Transformer Voltage System:

   (a) Rated MVA

   (b) Voltage Ratio

(c) Vector Group

(d) Positive sequence reactance (maximum, minimum, normal Tap (% on MVA)

(e) Positive sequence resistance (maximum, minimum, normal Tap (% on MVA)

(f) Zero sequence reactance (% on MVA)

(g) Tap changer range (+ % to - %) and steps

(h) Type of tap changer (OFF/ON)

(i) Details of reactors, and other circuits connected to tertiary winding of ICT

(j) Method of grounding

2 In relation to switchgear including circuit breakers, isolators on all circuits connected tothe points of connection:

(a) Rated voltage (kV)

(b) Type of breaker (MOCB/ABCB/SF6 ---)

(c) Rated short circuit breaking current (kA) 3 Phase

(d) Rated short circuit breaking current (kA) 1 Phase

(e) Rated short circuit making current (kA) 3 Phase

(f) Rated short circuit making current (kA) 1 Phase

(g) Provisions of auto reclosing with details.

(h) Details of instrument transformers

3 Lightning arresters, technical data

4. Communication- Details of PLCC and other communication equipment installed atConnection Point(s)/ Interface Point(s).

5. Basic insulation level (kV)

(a) Busbar

(b) Switchgear

(c) Transformer bushings

(d) Transformer windings

IV. Generating Units:

A. Parameters of Generating Units:

1. Rated terminal voltage (kV)
2. Rated MVA
3. Rated MW
4. Inertia constant H (MW Sec./MVA) of generator
5. Short circuit ratio
6. Direct axis synchronous reactance (% on MVA) (Both unsaturated and saturated)
7. Direct axis transient reactance (% on MVA) (Both unsaturated and saturated)
8. Direct axis sub-transient reactance (% on MVA) (Both unsaturated and saturated)
9. Quadrature axis synchronous reactance (% on MVA) (Both unsaturated and saturated)
10. Quadrature axis transient reactance (% on MVA) (Both unsaturated and saturated)
11. Quadrature axis sub-transient reactance (% on MVA) (Both unsaturated and saturated)
12. Direct axis transient open circuit time constant (Sec) T‟ do
13. Direct axis sub-transient open circuit time constant (Sec) Tdo
14. Quadrature axis transient open circuit time constant (Sec) T‟qo
15. Quadrature axis sub-transient open circuit time constant (Sec) Tqo

16. Stator resistance (Ohm)
17. Stator leakage reactance (Ohm) Ta
18. Stator time constant (Sec)
19. Rated field current (A)
20. Open circuit saturation characteristic for various terminal voltages giving the excitingcurrent to achieve the same.
21. Generator Capability Curve
22. Rated stator current (A)
23. Phase connection
24. Number of terminals brought out
25. Rated speed (rpm)
26. Rated Frequency (Hz.)
27. Efficiency at MCR condition (percent)
28. Negative sequence current capability (I2T)
29. Capacitance of generator stator winding to ground (microF/ph)
30. DC resistance of rotor at 200 C (in ohm)
31. Zero sequence reactance X0 (Percentage)
32. Negative sequence reactance X2 (Percentage)
33. Negative sequence reactance R2 (Percentage)
34. Sub-Transient S-C time constant (in second)
    a. Direct axis Td
    b. Quadrature axis Tq
35. Transient S-C time constant (in second)

a. Direct axis T‟d

b. Quadrature axis T‟q

36. Machine saturation at 1.0 pu voltage in pu

37. Machine saturation at 1.2 pu voltage in pu

38. Percentage regulation

39. Short circuit characteristics curves

B. Parameters of Excitation Control System:

1. Type of Excitation

2. Maximum Field voltage

3. Minimum Field voltage

4. Rated Field voltage

5. Gain factor

6. Feedback strength

7. Time constant for control amplifier

8. Time constant for Exciter

9. Time constant for Feedback

10. Output voltage of control amplifier

11. Maximum output voltage of control amplifier

12. Minimum output voltage of control amplifier

13. Details of excitation loop in block diagrams showing transfer functions of individual elements using IEEE symbols along with set values.

14. Dynamic characteristics of over - excitation limiter

15. Dynamic characteristics of under -excitation limiter

16. Exciter IEEE model / type no.

17. Exciter response time

C. Parameters of Governor/ Turbine:

1. Governor average gain (MW/Hz)

2. Speeder motor setting range

3. Time constant of steam or fuel governor valve

4. Governor valve opening limits

5. Governor valve rate limits

6. Time constant of turbine (HP, IP, LP)

7. Governor block diagram showing transfer functions of individual elements using IEEE symbols along with set values.

8. Type of governor, whether IEEE standard governor used

9. Regulation and droop

10. Fraction of total power generated HP, IP, LP turbine

11. Maximum velocity limit HP, IP, LP turbine

12. Minimum velocity limit HP, IP, LP turbine

D. Operational Parameters:

1. Min. notice required for synchronising a generating unit from de-synchronisation

2. Min. time between synchronising different generating units in a generating station

3. The minimum block load requirements on synchronising

4. Time required for synchronising a generating unit for the following conditions:

    a. Hot

b. Warm

c. Cold

5. Maximum Generating Unit loading rate for the following conditions:

a. Hot

b. Warm

c. Cold

6. Minimum load without oil support (MW)

V. Plant Performance:

Daily Demand Profile (Last Year)	Half-hourly integrated demand throughout the day
Units Generated (Million kWH)	
Units consumed in Auxiliaries (Million kWH)	
Units supplied from system to Auxiliary Load	
Seasonal Generation	

2.2 Hydroelectric Stations:

I. General:

1. Name of generating station:
2. No. and capacity of units (MW)
3. Expected level of generation (MU)
4. Period of generation (in months) per year
5. Whether the plant is based on water released from dam/canal for irrigation purposes
6. Rating of all major equipments.
   a. Turbine
   b. Generators
   c. Generator Transformers

d. Auxiliary Transformers

7. Single line diagram of generating station and switchyard

8. Relaying and metering diagram

9. Neutral grounding of generator

10. Excitation control

11. Earthing arrangements with earth resistance values

12. Communication- Details of PLCC and other communication equipment installed

II. Protection:

(As applicable to thermal generating stations mentioned above)

III. Switchyard:

(As applicable to thermal generating stations mentioned above)

IV. Generating Units:

A. Parameters of generating units:

(As applicable to thermal generating station mentioned above)

B. Parameters of Excitation Control System:

(As applicable to thermal generating stations mentioned above)

C. Parameters of governor/ turbine:

(As applicable to thermal generating stations mentioned above)

D. Operational Parameters:

(a) Minimum notice required for synchronising a generating unit from de-synchronisation

(b) Minimum time between synchronising different generating units in a generatingstation

(c) Minimum block load requirements on synchronising

3 Planning Data Generation

(For submission on request by STU)

3.1 For Thermal Generating Stations, if desired by STU:

Connection:

1. Report of studies of parallel operation with Transmission System:
   a. Load flow studies
   b. Stability studies
   c. Short Circuit studies
2. Proposed connection with Transmission system:
   a. Voltage
   b. No. of circuits
   c. Connection Point(s) / Interface Point(s)

3.2 For Hydroelectric Generating Stations, if desired by STU:

(As applicable to thermal generating stations mentioned above)

Part - II - Distribution

(To be furnished by the distribution company to STU)

Standard Planning Data Distribution

I. General:

1. Single Line Diagram	Licensee-wise up to 66kV substations.
2. Consumer Data	Furnish category wise number of consumers, their connected loads to the best judgement of the Distribution Licensee

3. Reference to area offices presently in charge of the distribution

II. Connection:

1. Connection Points/ Interface Points:	Furnish single line diagram showing Connection Points/ Interface Points.
2. Voltage of supply at Connection Points/ Interface Points:	
3. Names of Grid Substation feeding the	
Connection Points/ Interface Points:	

III. Lines and Substations:

1. Line Data:	Furnish length of line and voltages (EHV level)
2. Substation Data:	Furnish transformer details of 220/ 11kV,132/11 kV, 66/22 kV, 66/ 11 kV substations, capacitor installations

IV. Loads:

1.Loads drawn at ConnectionPoints/ Interface Points:	If the Distribution Licensee receive power at a number of connection points in a compact area, which are interconnected in a ring, then such a Distribution Licensee shall forward the overall load drawn for overallArea of Supply, as well as at each connection point with the variation or tolerance as mutually discussed andagreed upon with the STU.
2.Details of loads fed at EHVif any:	Give name of consumer, voltage of supply, contract demand and name of grid substation from which line isdrawn, length of EHT line from grid substation to the consumer's premises.

V. Demand Data (For All Loads 5 MW and Above):

1.Type of Load & Rating in HP or kW:	State whether furnace loads, rolling mills, traction loads, other industrial loads, pumping loads etc.
2.Rated voltage:	

3.Electrical loading of equipment:	State number and size of motors, rating of arc furnaces/ induction furnace, types of drive and control arrangements.
4.Sensitivity of load to voltage and frequency of supply:	
5.Maximum harmonic content of load:	
6.Average and maximum phase unbalance of load:	
7.Nearest substation from which load is to be fed:	
8.Location map to scale:	Map shall show the location of load withreference to lines and sub-stations in the vicinity.

VI. Load Forecast Data:

1. Peak load for Connection Point/ Interface Point as well as peak load and energy forecastfor Area of Supply for each of the succeeding five years.
2. Details of methodology and assumptions on which forecasts are based.
3. Details of load 5 MW and above.
   a. Name of prospective consumer.
   b. Phasing of load.

1 Detailed Planning Data (Distribution)

I. General:

1. Schematic single line diagram of Distribution System (showing distribution lines from Connection Points/ Interface Points with Transmission System 220kV/ 11kV, 132/11 kV, 66/22 kV & 66/ 11 kV substations, consumer bus if fed directly from Transmission System)
2. Numbering and nomenclature of lines and substations (identified with feeding grid substations of the Transmission System and concerned 220kV/11kV, 132/ 11kV, 66/22 kV & 66/11 kV substation).

II Connection:

1. Connection Points/ Interface Points (furnish details of existing arrangement ofconnection)
2. Details of metering of Connection Points/ Interface Points.

2 Detailed Planning Data (Distribution)

(For submission on request by STU)

I. Connection:

1. Connection Points/ Interface Points as applied for

a. New

b. Upgrading existing connection

2. Changes in metering at Connection Points/ Interface Points

II. Loads:

1. Details of major loads of 1 MW and above to be contracted for next three years.

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ANNEXURE-2

THIRD PARTY PROTECTION SYSTEM CHECKING & VALIDATION TEMPLATE FOR A SUBSTATION

1. INTRODUCTION

(1) The audit reports, along with action plan for rectification of deficiencies found, if any, shallbe submitted to SLDC within a month of submission of report by auditor.

(2) The third-party protection system checking shall be carried at site by the designated agency. The agency shall furnish two reports:

(a) Preliminary Report: This report shall be prepared on the site and shall be signed by allthe parties present.

(b) Detailed Report: This report shall be furnished by agency within one month aftercarrying out detailed analysis.

2. CHECKLIST

(1) The protection system checklist shall contain information as per these Regulations.

(a) General Information (to be provided prior to the checking as well as to be included infinal report):

(i) Substation name

(ii) Name of Owner Utility

(iii) Voltage Level (s) or highest voltage level?

(iv) Short circuit current rating of all equipment (for all voltage level)

(v) Date of commissioning of the substation

(vi) Checking and validation date

(vii) Record of previous tripping's (in last one year) and details of protection operation

(viii) Previous Relay Test Reports

(ix) Overall single line diagram (SLD)

(x) AC aux SLD

(xi) DC aux SLD

(xii) SAS architecture diagram

(xiii) SPS scheme implemented (if any)

(b) The preliminary report shall inter-alia contain the following:

TABLE : FORMAT OF PRELIMINARY REPORT

S. No.	Issues	Remarks
1	Recommendation of last protection checking and validation	Status of works and pending issues if any
2	Review of existing settings at substation	Recommended Action
3	Disturbance Recorder out available for last 6 tripping's (Y/N)	Recommended Action
4	Chronic reason of tripping, if any	Recommended Action
5	Major non-conformity/deficiencyobserved	Recommended Action

(c) The relay configuration checklist for available power system elements at station:

(i) Transmission Line

(ii) Bus Reactor/Line Reactor

(iii) Inter-connecting Transformer

(iv) Busbar Protection Relay

(v) AC auxiliary system

(vi) DC auxiliary system

(vii)Communication system

(viii) Circuit Breaker Details

(ix) Current Transformer Details

(x) Capacitive Voltage Transformers Details

(xi) Any other equipment/system relevant for protection system operation

(d) The minimum set of points on which checking and validation shall be carried out is covered in this Regulation. The detailed list shall be prepared by checking and validationteam in consultation with concerned entity, SLDC and STU.

(i) Transmission Line Distance Protection/Differential Protection

a. Name and Length of Line

b. Whether series compensated or not

c. Mode of communication used (PLCC/OPGW)

d. Relay Make and Model for Main-I and Main-II

e. List of all active protections & settings

f. Carrier aided scheme if any

g. Status of Power Swing/Out of Step/SOTF/Breaker Failure/Broken Conductor/STUB/Fault Locator/DR/VT fuse fail/Overvoltage Protection/Trip Circuit supervision/Auto-reclose/Load encroachment etc.

h. Relay connected to Trip Coil-1 or 2 or both

i. CT ratio and PT ratio

j. Feed from DC supply-1 or 2

k. Connected to dedicated CT core (mention name)

l. Other requirements for protection checking and validation

(ii) Shunt Reactor & Inter-connecting Transformer Protection

a. Whether two groups of protections used (Group A and Group B)

b. Do the groups have separate DC sources

c. Relay Make and Model

d. List of all active protections along with settings

e. Status of Differential Protection/Restricted Earth Fault Protection/Back-upDirectional Overcurrent/Backup Earth fault/ Breaker Failure

f. Status of Oil Temperature Indicator/Winding Temperature Indicator/Bucholz/Pressure Release Device etc.

g. Relay connected to Trip Coil-1 or 2 or both

h. CT ratio and PT ratio

i. Feed from DC supply-1 or 2

j. Connected to dedicated CT core (mention name)

k. Other requirements for protection checking and validation

(iii) Busbar Protection Relay

a. Busbar and redundant relay make and model

b. Type of Busbar arrangement

c. Zones

d. Dedicated CT core for each busbar protection (Yes/No)

e. Breaker Failure relay included (Yes/No), if additional then furnish make and model

f. Trip issued to both Busbar protection in case of enabling

g. Isolator indication and check relays

h. Other requirements for protection checking and validation

(iv) AC auxiliary system

a. Source of AC auxiliary system

b. Supply changeover between sources (Auto/Manual)

c. Diesel generator (DG) details

d. Maintenance plan and supply changeover periodicity in DG

e. Single Line Diagram

f. Other requirements for protection checking and validation

(v) DC auxiliary system

a. Type of Batteries (Make, vintage, model)

b. Status of battery Charger

c. Measured voltage (positive to earth and negative to earth)

d. Availability of ground fault detectors

e. Protection relays and trip circuits with independent DC sources

f. Other requirements for protection checking and validation

g. Communication system

i. Mode of communication for Main-1 and Main-2 protection

ii. Mode of communication for data and speech communication

iii. Status of PLCC channels

iv. Time synchronization equipment details

v. 7OPGW on geographically diversified paths for Main-1 and main-2relay

vi. Other requirements for protection checking and validation

(vi) Circuit Breaker Details

a. Details and Status

b. Healthiness of Tripping Coil and Trip circuit supervision relay

c. Single Pole/Multi pole operation

d. Pole Discrepancy Relay available(Y/N)

e. Monitoring Devices for checking the dielectric medium

f. Other requirements for protection checking and validation

(vii) Current Transformer (CT)/Capacitive Voltage Transformer (CVT) Details

a. CT/CVT ID name and voltage level

b. CT/CVT core connection details

c. Accuracy Class

d. Whether Protection/Metering

e. CT/CVT ratio available and ratio adopted

f. Details of last checking and validation of CT/CVT healthiness

g. Other requirements for protection checking and validation

h. Other protections: Direction earth fault, negative sequence, over current, over voltage, over frequency, under voltage, under frequency, forward power, reverse power, out of step/power swing, HVDC protection etc.

3. SUMMARY OF CHECKING:

The summary shall specifically mention minimum following points:

(1) The settings and scheme adopted are in line with agreed protection philosophy or anyaccepted guidelines (e.g. Ramakrishna guidelines or CBIP manual based).

(2) The deviations from the RPC protection philosophy, if any and reasons for taking thedeviations shall be recorded.

(3) All the major general deficiency shall be listed in detail along with remedial recommendations.

(4) The relay settings to be adopted shall be validated with simulation based or EMTP studiesand details shall be enclosed in report.

(5) The cases of protection maloperation shall be analysed from protection indices report furnished by concerned utility, the causes of failure along with corrective actions and recommendations based on the findings shall be noted in the report.

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ANNEXURE-3

GENERATION RESERVE ESTIMATION AND FREQUENCY CONTROL

1. CALCULATION OF ACTUAL FREQUENCY RESPONSE CHARACTERISTICS OFCONTROL AREA

(a) Frequency Response Characteristics (FRC) computations:

Frequency Response Characteristics (FRC) will be computed for all events involvinga sudden 1000 MW or more load or generation loss or a step change in frequency by 0.10 Hz i.e. for all reportable events as notified by NLDC. The FRC shall be worked out by NLDC, RLDCs and SLDCs for each interconnection/region/control area (including for each generating station). Each generating station shall also compute it's FRC. The following steps shall be followed for computation of FRC

(i) After every event involving a sudden 1000 MW or more load or generation loss or a step change in frequency by 0.1 Hz, NLDC would get the PMUs frequency data. NLDC would also get the exact quantum of load/generation lost from the RLDC of the affected region.

(ii) NLDC shall plot the frequency graph and determine the initial frequency, minimum/maximum frequency, settling frequency and time points (points A, C and B of the Figure-A). Accordingly, frequency difference points & corresponding time to be used for FRC calculations would be informed to all RLDCs.

(iii) SLDC shall work out FRC for all the intra-state entities (for events indicatedby the WRLDC) based on the HDR available at SLDC and submit the same to WRLDC within six (6) working days after the event. (Format as per Table-B).

(iv) All generating stations shall also assess the FRC for their respective stations and submit the same to respective SLDC within six (6) working days. (Format as per Table-B). The high resolution data (1 second or better resolution) ofactive power generation and frequency shall also be shared with SLDC.

(b) Input data for FRC:

(i) The data for frequency response characteristic Calculations may be taken from thereal time telemetered data recorded by the SCADA systems installed at SLDC.

(ii) Bad quality of data could be flagged / mentioned by the SLDC and reasonable assumptions made for FRC computation. Details of these may be mentioned.

(c) Instructions for computation of FRC:

A sample frequency chart given at Figure-A with points A, B, and C labelled depicts atypical frequency excursion caused by a loss of a large generator in Indian power system. Point A denotes the interconnection frequency immediately before the disturbance. Point B represents the Interconnection frequency at the point immediately after the frequency stabilizes due to governor action but before the contingent area takes any corrective actions, automatic or manual. Point C represents the interconnection frequency at its maximum deviation due to the loss of generation.

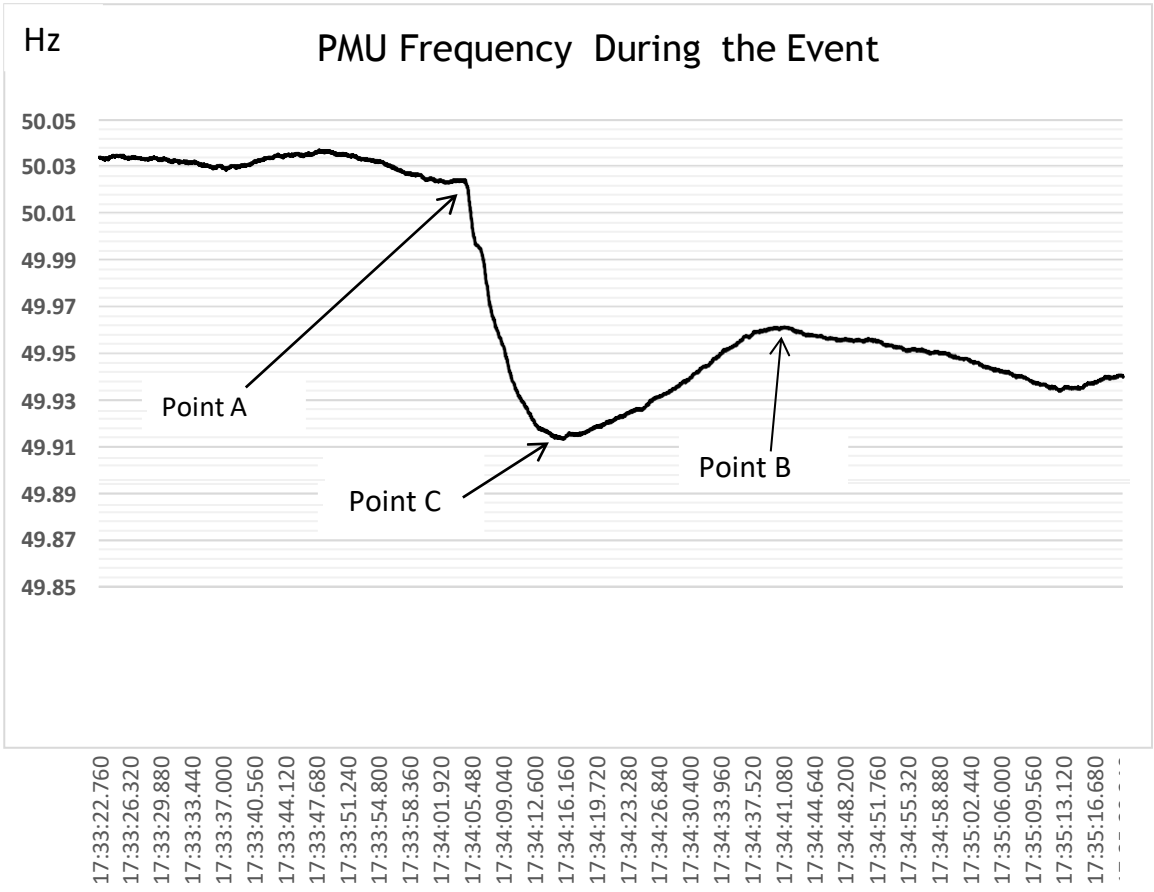

FIGURE A: SAMPLE PMU FREQUENCY PLOT SHOWING RELEVANT POINTS FOR FRC

CALCULATION

(d) Steps to work out frequency response characteristics of control area are as follows: -

Step-1: Actual net interchange of the control area immediately before the disturbance (Point

– A in the figure-A), say P_A. Sign convention for net power imported into a ControlArea is positive (+) and net power exported out of a control area is negative (-).

Step-2: Actual net interchange of the control area immediately after the disturbance (Point

– B in the figure-A), say P_B. Use the same sign convention as Step-1.

Step-3: The change in net interchange of the Control Area = (P_B -P_A). [For a disturbance that causes the frequency to decrease, this value should ideally be negative. The net interchange of a control area may be positive, if the drop in generation has occurred in that control area. Similarly, for load throw off or frequency rise cases ina control area, the net interchange shall normally be positive except for the ControlArea, where the load throw off has taken place.]

Step-4: If the control area has suffered the loss, then Load or generation lost by the controlarea = PL. Otherwise, the loss (PL) is zero. Sign convention for Load Loss is negative (-) and Generation Loss positive (+).

Step-5: The Control Area Response $\Delta P = (P_B-P_A) - P_L$

Step-6: The Frequency immediately before the disturbance = f_A.
Step-7: The Frequency immediately after the disturbance = f_B.

Step-8: Change in Interconnection Frequency from Point A to Point B = $\Delta f = (f_B - f_A)$

Step-9: Frequency Response Characteristic (FRC) of the Control Area = $\Delta P/ \Delta f$

Step-10: Frequency Response Obligation (FRO) of each control area calculated in advanceas per clause 3 of this Annexure

Step 11: Frequency Response Performance (FRP) = Actual Frequency ResponseCharacteristic (AFRC)/ Frequency Response Obligation (FRO)

TABLE: FRC CALCULATION SHEET TO BE USED BY ALL SLDC/RLDC/NLDC/CONTROL AREA

S. No	Particulars	Dimension	Control Area-1 /Region
1	Actual Net Interchange before the Event (Time= hh:mm:ss)	MW	
2	Actual Net Interchange after the Event (Time= hh:mm:ss)	MW	
3	Change in Net Interchange (2 - 1)	MW	
4	Generation Loss (+) / Load Throw off (-) during the Event	MW	
5	Control Area Response (3-4)	MW	
6	Frequency before the Event	Hz	
7	Frequency after the Event	Hz	
8	Change in Frequency (7-6)	Hz	
9	Frequency Response Characteristic (5 / 8)	MW/Hz	
10	Frequency Response Obligation (FRO) of control area	MW/Hz	
11	Frequency Response Performance (FRP)(9/10)	Numeric value (up to two decimal places)	

4 CALCULATION OF FREQUENCY RESPONSE PERFORMANCE

(a) The performance of each control area in providing frequency response characteristic shallbe calculated for each reportable event. Each control area shall separately assess their frequency response characteristic and share with SLDC along with high resolution data ofat least one (1) second for regional entity generating stations and ten (10) second for statecontrol area.

Frequency Response Performance (FRP) = Actual Frequency Response Characteristic (AFRC)/ Frequency Response Obligation (FRO)

Each control area shall be graded based on median Frequency Response

Performance annually (at least 10 events) as per following criteria:

TABLE : FREQUENCY RESPONSE CRITERIA

S. N	Performance*	Grading
i.	FRP≥ 1	Excellent
ii.	0.85 ≤ FRP < 1	Good
iii.	0.75 ≤ FRP <0.85	Average
iv.	0.5≤ FRP < 0.75	Below Average
v.	FRP <0.5	Poor

**Provided that for wind/solar generating stations and state control areas with internal generation less than 100 MW or annual peak demand less than 1000 MW, the FRP grading shall be indicative only.*

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ANNEXURE-4

PROTECTION STANDARDS

1. Introduction

This standard provides guidelines for the following:

(a) Minimum requirement of protection to be provided to safeguard the system from faults which may occur.

2. Protection Requirements

General Principles

3.1 No item of electrical equipment shall be allowed to remain connected to the system, unless it is covered by the appropriate protection aimed at reliability, selectivity, speed and sensitivity. The guidelines mentioned in the manual on protection of generators, generator transformers, and 220 kV and 400 kV networks vide publication no 274 of C.B.I.P shall be kept in view. All the generating companies and Distribution Licensees shall cooperate with the Transmission Licensee(s) to ensure correct and appropriate settings of protection to achieve effective, discriminatory isolation of faulty line/equipment within the target clearance times specified elsewhere in this standard.

3.2 Protection settings shall not be altered, or protection bypassed and/or disconnected without consultation and agreement of all affected Users. In case the protection has been bypassed and/or disconnected by agreement due to any cause, the same should be rectified and protection restored to normal conditions, as quickly as possible. If agreement has not been reached, the electrical equipment shall be isolated forthwith.

3. Protection Coordination

3.1 The settings of protective relays starting from the generating unit up to the remote end of 66 kV / 33 kV and 11 kV lines shall be such that only the faulty section is isolated under all circumstances. The Transmission Licensee shall notify the initial settings and any subsequent changes to the Users from time to time. Routine checks on the performance of the protective relays shall be

conducted and any malfunction shall be noted and corrected as soon as possible. The Transmission Licensee shall conduct the required studies for deciding the relay settings, with the data collected from the Users. Representatives of the generating companies, Transmission Licensees and Distribution Licensees shall meet periodically to discuss such malfunctions, changes in the system configuration, if any, and possible revised settings of relays.

3.2 The Transmission Licensee shall be responsible for arranging periodical meetings between the generating companies and Distribution Licensees to discuss coordination of protection. The Transmission Licensee shall investigate any malfunction of protection or other unsatisfactory protection issues. The concerned licensees shall take prompt action to correct any protection malfunction or issue as discussed and agreed to in these periodical meetings.

4. Fault Clearance Time

4.1 From stability considerations, the maximum Fault Clearance Time for faults on any user'ssystem directly connected to the Transmission System, or any faults on the Transmission System itself, shall be as follows:

Voltage Class	Target Clearance Time
400kV	100 milliseconds
220kV	120 milliseconds
132kV	160 milliseconds
66kV	300 milliseconds

4.2 Less Fault Clearance Time than the above is preferable.

4.3 Lower Fault Clearance Times for faults on a user's system may be agreed to, but only if, in the opinion of the Transmission Licensee, system conditions allow the same. At the generating stations, line faults should be cleared at the generating station end, within the critical time, to keep the generators in synchronism.

5 Generator Requirements

All generating units and all associated electrical equipment of the generating

company connected to the Transmission System shall be protected by adequate protection, as per CBIP manual vide publication 274, so that the Transmission System does not suffer dueto any disturbances originating at the generating unit.

6 Transmission Line Requirements

Every EHT line taking off from a generating station or a substation or a switching station shall necessarily have distance protection along with other protection as follows:

(a) **400 kV lines**: - These lines shall have two main distance protections; viz. Main I and Main II with permissive inter trip for remote earth fault. Three zone static/numerical non-switched distance protection with permissive inter trip for accelerated tripping at remote end in case of zone 2 fault as Main I protection shall be provided. Main II protection shall be similar fast protection using direction comparison or phase comparison carrier relay scheme. In addition to the above, single pole tripping and single shot single pole auto reclosing after an adjustable dead time shall be provided. In addition to the above, back- up protection with OCR and EFR shall be provided.

(b) **220 kV lines**: - Three zone static/numerical non-switched distance protection, with permissible inter-trip for end zone fault as main protection in case of zone 2 fault shall be provided. The back-up shall be three-phase directional over current relay and earth fault relay protection. Three pole tripping and Single Shot Three Pole Auto**-**reclosing with adjustable dead time shall be provided for the stability of the power system. However, forshort 220 kV lines directional comparison or phase comparison carrier protection as MainII can be provided. In addition to the above back-up protection with directional OCR (Over Current Relay) and directional EFR (Earth Fault Relay) shall be provided.

(c) **132 kV lines**: - Three zone static/numerical switched protection with permissible intertrip for accelerated tripping at the remote end in case of zone 2 protection shall be provided as main protection. The back-up will be directional three-phase over current andearth fault protection.

(d) **Busbar Protection**: - Adequate busbar protection for the station busbar sections in all 400 kV and 220 kV class substations shall be provided.

(e) **Local Breaker Backup Protection (LBB)**: - In the event of any circuit breaker

failing to trip on receipt of trip command from protective relays, all circuit breakers connected to the bus section to which the faulty circuit breaker is connected are required to be tripped with minimum possible delay through LBB protection. This protection also provides coverage for faults between the circuit breaker and the current transformer, which are not covered by other protections. All 220 kV and 400 kV circuits shall have Local Breaker Back-up Protection.

(f) **400 kV class Power Transformers**: - These shall be provided with differential protection, restricted earth fault protection, Bucholtz protection, and winding temperature protection along with back-up directional HV & LV IDMT over current protection.

(g) **220 kV, 132 kV and 66 kV class power transformers**: These shall have differential protection, restricted earth fault protection, Bucholtz protection, and winding/oil temperature protection. They shall also have directional over current as back-up protection with an instantaneous element. In addition to the above, Over Fluxing Relays, pressure relief valves/diaphragms shall be provided for all the power transformers. Appropriate fire protection for all the power transformers as per CBIP specifications and tariff advisory committee recommendations shall be provided. Over Fluxing Relays shall be provided on transformers having rating more than 100 MVA.

(h) **Distribution System**: For smaller transformers of HV class on the distribution system, differential protection shall be provided for 8 MVA capacity and above, along with back- up time lag over current and earth fault protection with directional feature for parallel operation. Transformers of 1.6 MVA capacity and above, but less than 8 MVA shall be protected by time lag over current, earth fault and instantaneous restricted earth fault relays. In addition, all transformers of 1.6 MVA and above shall be provided with gas operated relays, winding and oil temperature protection.

(i) **Distribution Lines**: All the 33 kV, 22 kV and 11 kV lines at Connection Points/ InterfacePoints shall be provided with a minimum of over current and earth fault relays as follows:

(j) **Plain Radial Feeders**: Directional over current and earth fault relays with suitablesettings to obtain discrimination between adjacent relay settings.

(k) **Parallel/Ring Feeders**: Directional time lag over current and earth fault relay.

(l) **Inadvertent Flow**: - When two systems are operating in parallel with floating tie-line, it may not be possible to have tie-line absolutely floating because of dynamics of network parameters and there will be a flow of energy from one system to another system. Such inadvertent flow shall be accounted for the purpose of commercial billing.

<<<<<<>>>

ANNEXURE-5

Requisition for Line Clear Permit

Date ……

Time ……

I Mr/Ms ----------request Line Clear Permit on the following HT/EHT line/equipment

1. **HV/EHV Apparatus/Line Identification:**

Details of works to be carried out:

2. **Estimated time required for completion:**

Name and Signature ……

……

(Requesting Safety Coordinator) (In-charge of crew)

Designation …… ……

Date …… ……

(For use in substation from where Line Clear Permit will be issued)

(a) Line Clear Permit issued : Yes/No

(b) Number and date of issue (Code No.):

(c) Time of issue:

(d) Date & time of return:

(e) Remarks: see check list LCP - H

3. Receipt of LCP

I have received confirmation from .....(name of issuing safety coordinator) at .....(location) that the safety precautions have been established and the instructions will not be issued at his location for their removal until his LCP- H is cancelled.

Name and Signature.....

(Requesting safety coordinator)

In charge of the crew at .....(time) on ..... (date)

(To be printed on the reverse of LCP-H: Checklist of Line Clear Permit)

4. Conditions:

(a) This permit is valid only for working in the feeder/equipment mentioned herein and notin any other feeder/equipment.

(b) Only authorised persons are allowed to work on feeders/equipments for which the permithas been issued.

(c) Works as per requisition only should be carried out.

(d) Before touching any part of the feeder/equipment, the same should be earthed at two points on either side through standard discharge rods connected with good earth. Temporary earthing may only be removed after completion of all works and after all the men have come down from the feeder/equipment.

(e) Work should be so planned that the Line Clear is returned before or at the time indicated. If unavoidable delay is anticipated, advance information should be given to the location from where the Line Clear is issued.

(f) Before return of the Line Clear, it should be ensured that all the men, materials,

tools/tackles etc. on line have returned and reported that all temporary returned and reported and all temporary earths removed. There should also be a check on the material, tools and plant issued for the work to ensure that nothing is left behind on the line or equipment.

(g) Only authorised persons should return Line Clear.

(h) In case the Line Clear cannot be returned in person, the same may be returned to the LineClear Issuing Authority over telephone by naming the code words assigned and the telephone number which is used for naming the code words assigned. In case two or more different code words are issued to the two or more persons in whose favour the permit is given, those persons must jointly return the Line Clear by naming their own code words. The Line Clear Return will not be deemed to be accepted unless returned by all these persons.

(i) The Line Clear issuing authority should go over the checklist of Line Clear Return beforeaccepting it.

(j) If Line Clear is returned over telephone, the Line Clear return form duly filled and signed should be sent to the Line Clear issuing authority by post immediately for record.

(k) Control person should keep all the required data of LCP issued & LCR received. He should monitor and keep specific note in log sheet when more than one LCP are issuedon same line/ equip/bay along with code words.

<<<<<<>>>

ANNEXURE-6

Check list for Line Clear Permit and Line Clear Permit

LCP-H Number .....

Dated ..... Time.....

1. **Check List of the Line Clear Permit:**

   (a) Name of location for which line clear is issued

   (b) Reference and authority requisitioning Line Clear: (Indicate original LCP-G numberincluding suffix and prefix)

   (c) Identity of HV Apparatus

   (d) Sources from which the line/equipment is charged

   (e) Number/name of circuit breaker/isolating switch open at each of above sources

   (f) Whether confirmed that the line is disconnected at both ends

   (g) Whether line is earthed at both ends

   (h) Whether circuit breaker truck removed in case of indoor switchgear controlling thefeeder/equipment for which line clear is given

   (i) Whether fuses of control supply voltage of the circuit breaker/isolating switches controlling the feeder/equipment for which line clear is given are removed and kept in safe custody

   (j) Time of issue of Line Clear Permit and LCP-G No.

   (k) Name of requesting safety coordinator on whom LCP-G is issued

   (l) Approximate time for returning LCP-G as ascertained from the requesting coordinator

Name and Signature……..

(Issuing Safety Coordinator)

Designation……

a. Line Clear Permit

LCP - G No……

I, Mr/Ms.---------- (Issuing Safety Coordinator) do hereby issue permission to Mr/Ms.----------

--- (Requesting Safety Coordinator) for carrying out works as per requisitionNo……..date……..time .....

The EHV/ HV Line/equipment herein described is declared safe. The permission is subject to theconditions given in LCP-F.

Name and Signature……..

(Person issuing Line Clear Permit)

Designation……

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ANNEXURE-7

Line Clear Return

LCP - I Number……

Date …… Time……

LCP-H No……. Dated…….

I, Mr/Ms. ---------- hereby return the LCP No. -----at (time) for the following HT/EHT

Line/Apparatus. I declare that all the crew who were sent on work have been withdrawn, temporary earth(s) removed, all repair tools and materials checked and the feeders/equipment mentioned below are safe to be energised.

(a) HV/EHV Apparatus/Line Identification**:**

(b) Safety precaution no longer required:

(c) Isolation [state locations and each point of isolation indicating means by which isolationwas achieved]

(d) Earthing [state location at which earthing was established and identify each point ofearthing

(e) Details of work done

b. Check list to be ticked off:

(a) Whether all men withdrawn: *Yes/No*

(b) Whether all temporary earth removed: *Yes/No*

(c) Whether materials, tools and plant used in the work have been checked: *Yes/No*

(d) Code Number (If used when Line Clear is returned over phone) ----------

Name and Signature……

(Requesting Safety Coordinator)

Designation……

In-charge of Crew ..... (Designation)

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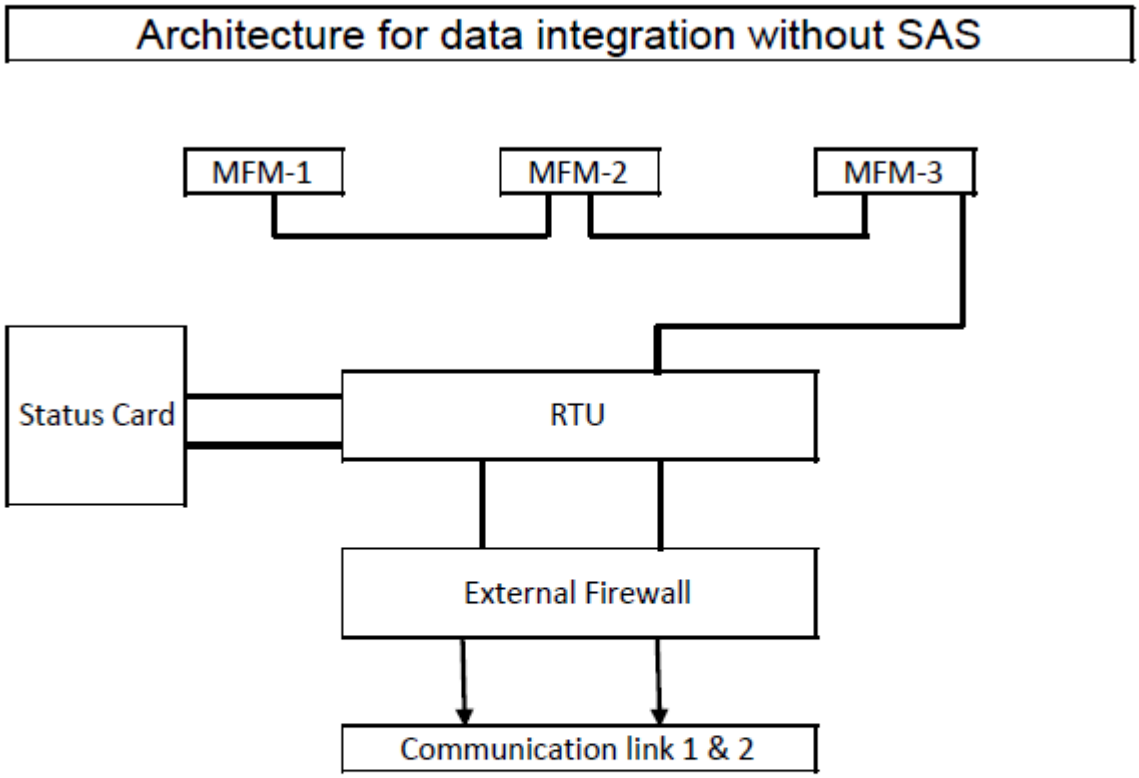
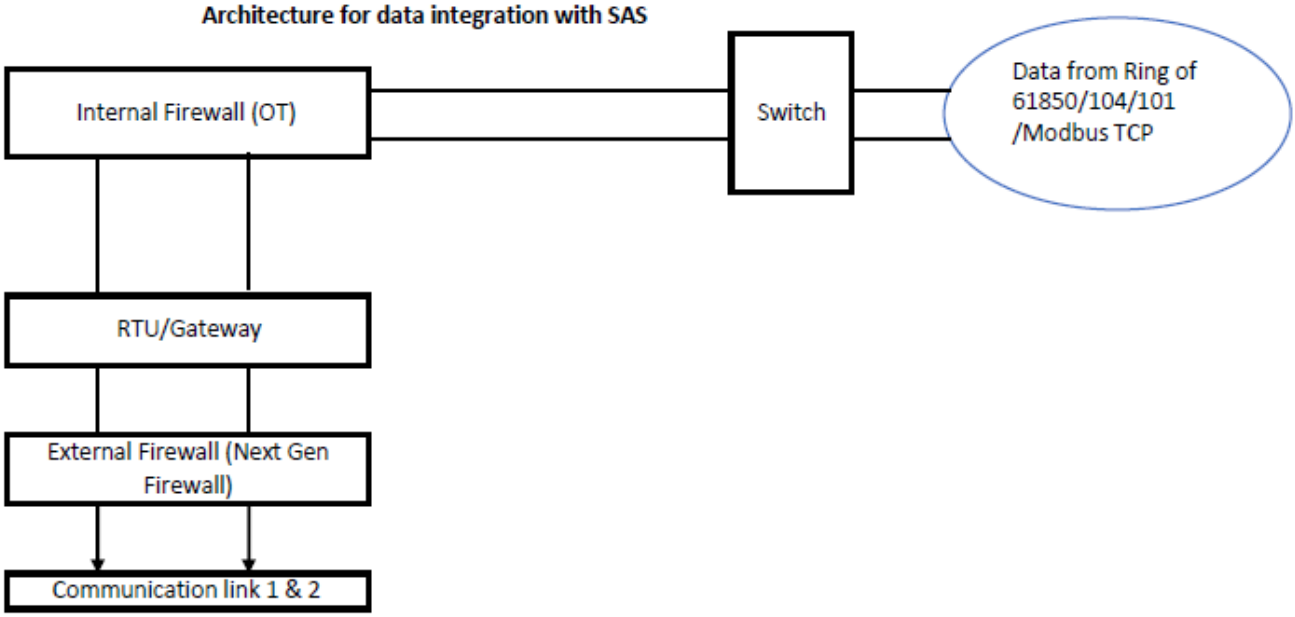
ANNEXURE-8

Cyber security Architecture for data integration of RTU/SAS with SLDC/Sub SLDC



Analog Protocol	Modbus, Modbus TCP, IEC-101, IEC-104, IEC-61850
Status data Protocol	IEC-101, IEC-104, IEC 61850, DNP 3.0
RTU to FEP	IEC-101 and IEC-104

Architecture for data integration with SAS



Data reporting to SLDC/SubSLDC- IEC104, IEC 101

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GUJARAT ELECTRICITY REGULATORY COMMISSION

Draft Gujarat Electricity Regulatory Commission (Grid Interactive Battery Energy Storage System) Regulations, 2026

Notification No. ____ of 2026

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LIST OF ABBREVIATIONS

Abbreviation	Full form
ARR	Aggregate Revenue Requirement
BESS	Battery Energy Storage System
BESSD	Battery Energy Storage System Developer
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CGP	Captive Generating Plant
CGRF	Consumer Grievance Redressal Forum
DSM	Deviation Settlement Mechanism
ESO	Energy Storage Obligation
EV	Electric Vehicle
G2V	Grid-to-Vehicle
GEDA	Gujarat Energy Development Agency
GERC	Gujarat Electricity Regulatory Commission
IEGC	Indian Electricity Grid Code
IPP	Independent Power Producers
MYT	Multi-Year Tariff
PAF	Plant Availability Factor
RA	Resource Adequacy
REC	Renewable Energy Certificates
RTE	Round Trip Efficiency
SLDC	State Load Despatch Centre
STU	State Transmission Utility
V2G	Vehicle-to-Grid

NOTIFICATION

Draft Gujarat Electricity Regulatory Commission (Grid Interactive Battery Energy Storage System) Regulations, 2026

NOTIFICATION NO. ____ of 2026

GERC-_____: Gujarat Electricity Regulatory Commission in exercise of the powers conferred by sub-Section (2) of Section 181 read with Section 61, Section 66 and Section 86 of the Electricity Act, 2003 (36 of 2003) and all other powers enabling it in that behalf, hereby makes the following Regulations, namely:

Chapter 1: Preliminary and Conceptual Framework

1 Short title and commencement

1.1 These Regulations shall be called the Gujarat Electricity Regulatory Commission (Grid Interactive Battery Energy Storage System) Regulations, 2026.

1.2 These Regulations shall extend to the whole of the State of Gujarat.

1.3 These Regulations shall come into force on the date of their publication in the Official Gazette of the State of Gujarat.

2 Definitions and Interpretation

2.1 In these Regulations, unless the context otherwise requires:

(a) **'Act'** means the Electricity Act, 2003 (36 of 2003);

(b) **"Aggregator(s)"** means an entity registered/ appointed with/by the distribution licensee to provide aggregation of one or more services like demand response services under the demand response mechanism, distributed generation, energy storage, etc.;

(c) **"Ancillary Services" or "AS"** means the services necessary to support the operation of the power system for maintaining grid frequency, voltage, reliability, and security, and includes Primary Reserve Ancillary Service (PRAS), Secondary Reserve Ancillary Service (SRAS), Tertiary Reserve Ancillary Service (TRAS), reactive power support, black start services, and such other services as may be specified by the Commission or as defined in the Indian Electricity Grid Code Regulations from time to time;

(d) **"Associated Generating Plant"** means a generating plant in which a co-located BESS is installed, and which is treated for the purposes of charging of co-located BESS under the applicable regulatory framework;

(e) **"Battery Energy Storage Systems"** or **"BESS"** shall mean electrochemical devices connected to the Power System that absorb electricity from the grid or generation sources, store it in the form of chemical energy, and discharge it, in the form of electricity, when required. They typically include batteries, power conversion system, and battery management system;

(f) **"Battery Energy Storage System Developer" or "BESSD" or "Developer"** shall mean the entity developing/owning/operating the BESS facility for supply of power under these Regulations;

(g) "**Captive Generating Plant" or "CGP"** shall have the same meaning as assigned to it under the Act;

Provided that, the captive status of a Captive Generating Plant with a co-located Battery Energy Storage System shall be determined in accordance with the applicable captive policy framework and the relevant Regulations, Rules, or Orders.

(h) **"Co-located BESS"** means a BESS installed at the same location and connected to the same evacuation infrastructure as a generating station, including renewable or conventional generation, for purposes such as firming of power, smoothing, or enhancing despatchability;

(i) **"Commission"** means the Gujarat Electricity Regulatory Commission (GERC);

(j) **"Distribution Licensee"** shall have the same meaning as assigned to it under the Act;

(k) **"Generating company"** shall have the same meaning as assigned to it under the Act;

(l) **"Prosumer"** means a consumer of electricity in the area of supply of the Distribution Licensee, having distributed generation, with or without a battery storage system, who consumes electricity and can inject the electricity back to the grid using the same network, in accordance with arrangements specified in these Regulations.

(m) **"Renewable Energy sources"** includes sources defined by the Government of India from time to time, under the Electricity Act, 2003.

(n) **"Standalone BESS"** means a BESS operating independently, not a part of an integrated renewable plus storage asset, and capable of participating in energy markets, capacity markets, or ancillary services;

(o) **"State Load Despatch Centre" or "SLDC"** shall have the same meaning as assigned under the Act and shall be responsible for integrated operation of the power system within the State;

2.2 Save as aforesaid and unless repugnant to the context or the subject-matter otherwise requires, words and expressions used in these Regulations and not defined, but defined in the Act, or the Gujarat Electricity Grid Code/Indian Electricity Grid Code (IEGC) (as applicable) or any other Regulation of the Commission/Central Electricity Regulatory Commission (CERC) shall have the meaning assigned to them respectively in the Act or the Grid Code or such other Regulation.

2.3 Reference to any Act, Rules and Regulations shall include amendments or consolidations or re-enactment thereof.

3 Scope and Applicability

3.1 These Regulations shall apply to the planning, procurement, development, deployment, operation, scheduling, despatch, and utilisation of Grid Interactive BESS within the State of Gujarat.

3.2 These Regulations shall be applicable to all entities including:

- Generating Companies
- Transmission Licensees
- Distribution Licensees
- Standalone BESS Developers
- Captive Generating Plants
- Consumers/Prosumers with storage under Net Metering/ Gross Metering/ Net Billing/ Group Net Metering/ Virtual Net Metering arrangements
- Aggregators for aggregating storage services

3.3 Applicability shall extend to BESS developed and deployed under these regulations.

3.4 All type of BESS projects connected to Intra-State Transmission Network or Distribution network and to be installed in the State of Gujarat shall be required to be registered with Gujarat Energy Development Agency (GEDA).

Provided that no separate registration shall be required for a BESS which is integrated and installed as part of a new Renewable Energy project, subject to the condition that the registration of such Renewable Energy project clearly includes the BESS component, its capacity, configuration, location and interconnection details.

3.5 GEDA shall, in consultation with the STU, SLDC, distribution licensees and other concerned agencies, prepare and notify a detailed Standard Operating Procedure consisting of application processing, documentation requirements, technical particulars, issuance of registration and commissioning certificate of grid-connected BESS projects in the State of Gujarat, in accordance with these Regulations, within three months from the date of notification of these Regulations.

4 Objective

4.1 The objectives of these Regulations are to provide a comprehensive framework for the deployment and utilisation of BESS in the State, including but not limited to:

a) Enhancing flexibility, reliability, stability and security of the power system;

b) Enabling efficient and optimal utilisation of battery energy storage resources;

c) Enabling the efficient utilization of renewable energy and addressing the issues related to intermittency of renewable energy.

d) Enabling deployment and utilisation of BESS as part of generation, transmission, and distribution assets;

e) Establishing a framework for procurement and enabling business models for deployment of BESS;

f) Enabling participation of BESS in grid support services and electricity markets.

g) Establishing a framework for Aggregators and third-party BESS developers to participate in the electricity market.

h) Enabling compliance with Energy Storage Obligation (ESO) targets for obligated entities in accordance with the provisions specified under the GERC (Procurement of Power from Renewable Energy Sources) Regulations, 2025, as amended from time to time.

5 Ownership of BESS

5.1 BESS may be developed, owned and operated by Generating Companies, Transmission Licensees, Distribution Licensees, Independent Power Producers (IPPs), Captive Generating Plants, Renewable Power Developers, Independent Storage Service Providers, Consumers/ Prosumers or Aggregators, subject to compliance with applicable Laws, Regulations and directions issued by the Commission.

5.2 Nothing contained in these Regulations shall restrict the participation of any entity in development or operation of BESS, subject to applicable statutory provisions.

6 Business Models for BESS

6.1 BESS may be deployed and operated under one or more of the following business models:

- Co-located with new/ existing renewable or conventional generators;
- Grid-connected standalone storage;
- Embedded in distribution or transmission networks;
- Battery Energy Storage under Net Metering/ Gross Metering/ Net Billing/ Group Net Metering/ Virtual Net Metering arrangements;
- Integrated with Electric Vehicle (EV) Charging stations and battery swapping

stations, including for Vehicle-to-Grid (V2G) services and Grid-to-Vehicle (G2V) services;

Provided that generating plant/ captive generating plant shall be allowed to install only a co-located BESS, which shall be charged using electricity generated from the associated generating plant/ captive generating plant.

Provided further that grid-connected standalone storage projects may be installed by third-party service providers, for providing storage services to licensees and/or sell power into the market or to participate in ancillary service or any other such services.

6.2 BESS shall have the same legal status as that of the owner:

Provided that for the standalone BESS, owned and operated by the licensees, the legal status shall still be that of the owner, but for the purpose of scheduling and despatch and other matters, it shall be treated at par with a separate storage element.

6.3 The Commission may, from time to time, recognise or approve additional business models for deployment of BESS.

6.4 A standalone BESS can also serve multiple functions, provided that the allocation for capacity for each of these functions are earmarked accordingly for the same, and each allocated capacity shall abide by its commitments, so as not to encroach on the commitments of the other earmarked allocation.

Chapter 2: Planning, Procurement and Deployment of BESS

7 General Principles for Planning, Procurement and Deployment of BESS

7.1 All entities shall consider deployment of BESS as an integral component of system planning, resource adequacy, and grid flexibility enhancement.

7.2 The minimum individual BESS project size shall be 1 MW (power rating) or higher, with a corresponding energy rating of at least two hours, and shall be connected at 11 kV or above.

Provided that this minimum size does not apply to BESS installed at the Distribution Transformer (DTR) level, or co-located with Captive Generating Plants, or for BESS installed under Net Metering/ Gross Metering/ Net Billing/ Group Net Metering/ Virtual Net Metering arrangements by consumers/ Prosumers.

Provided further that for BESS co-located with existing generating stations, the minimum energy rating requirement may be reduced to less than two hours where the primary application is ancillary services/ frequency regulation.

Provided also that the Commission may, from time to time, review and revise the minimum project size through separate order to adapt to technological advancements and market conditions.

7.3 The planning, procurement and deployment of BESS shall be undertaken in a manner that ensures:

a) Optimal utilisation of storage capacity;

b) Efficient integration of renewable energy sources;

c) Enhancement of system reliability, resilience and security;

d) Economic efficiency in comparison with alternative solutions; and

e) Alignment with applicable policies, including Energy Storage Obligations (ESO) and renewable energy targets.

7.4 BESS may be deployed as:

a) A generation-linked asset;

b) A transmission system asset;

c) A distribution system asset; or

d) A standalone storage asset.

e) Prosumer / Consumer owned asset

7.5 BESS shall preferably be procured as a service through competitive bidding under Section 63 of the Act, with tariff discovered as a Availability-based fixed charge in accordance with the prevailing Guidelines of the Ministry of Power, Govt. of India dated 10th March, 2022, for Procurement and Utilization of Battery Energy Storage Systems as part of Generation, Transmission and Distribution assets, along with Ancillary Service,

or any updated Guidelines, or the Guidelines of the Govt. of Gujarat, which adopt the same, with or without modification, if any. The bidding parameters may also specify performance parameters such as charging/discharging rate, efficiency, ramp rate, etc., depending upon the requirements of the specific use of BESS. The tariff discovered through the competitive bidding process may be adopted by the Commission in line with existing regulations.

Notwithstanding the foregoing, procurement of BESS under Section 62 shall be permitted only in exceptional circumstances, with the prior permission from the Commission. Such approvals shall be granted upon submission of adequate rational demonstrating the necessity and justification as to why procurement of BESS service through competitive bidding route is not feasible along with the techno-commercial analysis for such procurement, and ensuring compliance with the applicable Regulations, technical norms / standards, and tariff principles, while taking into account prevailing market conditions and the availability of cost-effective alternatives.

7.6 Transmission and distribution licensees may evaluate deployment of BESS as an alternative to conventional network augmentation.

7.7 Where a BESS is proposed for purposes other than compliance with ESO obligations, the licensee shall undertake a techno commercial feasibility assessment of the project, including a cost-benefit analysis comparing the proposed BESS deployment with conventional alternative solutions, and shall submit the same to the Commission for approval.

7.8 The technical standards for construction of BESS shall be guided by Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulation, 2022, as amended from time to time.

8 Generation linked BESS

8.1 Planning of Generation-linked BESS

8.1.1 Generating Companies may plan to install co-located BESS with existing or upcoming generating stations, including renewable and conventional generating stations.

8.1.2 The planning of BESS by generating entities shall primarily be for:

a) Firming and shaping of renewable energy output;

b) Compliance with contractual obligations including despatchability requirements;

c) Participation in electricity markets including energy and ancillary services;

d) Optimisation of generation scheduling and reduction of deviations.

8.1.3 If BESS is co-located with renewable energy projects, such BESS may be considered as part of hybrid or firm power arrangements, subject to applicable Regulations.

8.2 Procurement of Generation-linked BESS

8.2.1 Generating entities may procure or develop BESS through:

a) Competitive procurement; or

b) Third-party arrangements including leasing or service contracts.

8.2.2 Where BESS is developed as part of a competitively bid project under Section 63 of the Act, the tariff shall be discovered through such bidding process as per the prevailing MoP guidelines.

8.2.3 All procurement proposals under these Regulations shall require approval of the Commission.

8.3 Deployment of Generation-linked BESS

8.3.1 Co-located BESS shall be operated as part of the generating station for the purpose of scheduling and despatch, unless otherwise specified.

Provided that where a BESS is co-located and integrated with generating station / Renewable Energy generating station, no separate connectivity / open access approval shall be required for such BESS, so long as the total injection at the interconnection point does not exceed the connectivity capacity / open access quantum granted to such generating station / Renewable Energy generating station:

Provided that the total injection from the project, including injection from the Renewable Energy generating component and the BESS component, shall not exceed the connectivity quantum / sanctioned capacity / open access quantum granted to such project, as applicable. Any injection beyond such granted quantum shall be treated as inadvertent injection and shall not be eligible for any commercial settlement.

Provided further that such integration shall be subject to compliance with applicable Grid Code, connectivity, metering, protection, scheduling and communication requirements, orders / regulations of the Commission, as applicable.

9 Transmission linked BESS

9.1 Planning of Transmission BESS

9.1.1 Transmission Licensees shall consider BESS as part of transmission system planning.

9.1.2 BESS may be planned for:

a) Congestion management in transmission corridors;

b) Deferral of transmission network augmentation;

c) Integration of large-scale renewable energy;

d) Provision of grid support services;

e) Enhancement of system reliability and contingency support.

9.1.3 Transmission licensees, in coordination with the SLDC and STU, shall identify strategic locations for deployment of BESS in the transmission network and shall form part of

the State Transmission System Plan framed by the STU.

9.2 Procurement of Transmission BESS

9.2.1 Transmission Licensees shall primarily procure BESS through competitive bidding process under Section 63 of the Act as per the prevailing MoP guidelines.

9.2.2 All procurement proposals shall require approval of the Commission.

9.3 Deployment of Transmission BESS

9.3.1 The transmission licensees may consider deployment of BESS as part of transmission planning and shall coordinate with the SLDC for optimal utilisation of such systems.

9.3.2 The transmission licensee may deploy BESS as part of the transmission system where such deployment is found to be technically and economically feasible.

10 Distribution linked BESS

10.1 Planning of Distribution BESS

10.1.1 Distribution Licensees shall assess the requirement for deployment of BESS as part of distribution system planning or resource adequacy planning.

10.1.2 Planning shall consider:

a) Peak demand management;

b) Integration of distributed renewable energy resources;

c) Reduction of network losses;

d) Voltage regulation and power quality improvement;

e) Compliance with Energy Storage Obligations;

f) Management of deviation charges.

10.1.3 The Distribution Licensee shall, while planning and procuring BESS, duly consider the requirements arising from Energy Storage Obligations (ESO) specified under applicable Regulations, including the GERC (Procurement of Power from Renewable Energy Sources) Regulations, 2025, and align such procurement with its power procurement strategy.

10.1.4 Distribution licensees, in coordination with the SLDC/STU, may identify strategic locations for deployment of BESS in the distribution network.

10.2 Procurement of Distribution BESS

10.2.1 Distribution Licensees shall procure BESS primarily through competitive bidding under Section 63.

10.2.2 All procurement proposals shall require approval of the Commission.

10.3 Deployment of Distribution BESS

10.3.1 Distribution BESS may be deployed:

a) At substations;

b) At feeder level

c) At Distribution Transformer Level

d) At consumer level through aggregation.

10.3.2 Distribution Licensees shall maintain a database of BESS installed under Net Metering/ Gross Metering/ Net Billing/ Group Net Metering/ Virtual Net Metering arrangements within their licensed area.

11 Standalone BESS

11.1 Planning of Standalone BESS

11.1.1 Standalone BESS Developers may establish storage systems at locations identified based on market opportunities, grid requirements, or contractual arrangements.

11.1.2 Such planning shall consider:

a) Proximity to load centres or renewable generation;

b) Grid connectivity;

c) Market participation opportunities.

11.2 Procurement and Commercial Framework for Standalone BESS

11.2.1 Standalone BESS may operate under:

a) Merchant model;

b) Bilateral contracts;

c) Capacity or ancillary service contracts.

11.2.2 Procurement of services from standalone BESS by licensees shall be through competitive mechanisms under Section 63 of the Act ..

11.3 Deployment of Standalone BESS

11.3.1 Standalone BESS shall be treated as independent entity for scheduling, despatch and market participation as per the prevailing regulations.

11.3.2 Such BESS may provide the following services:

a) Energy arbitrage;

b) Ancillary services;

c) Capacity support;

d) Other grid services.

Chapter 3: Scheduling, Despatch, Energy Accounting & Ancillary Services

12 General Principles for Operation of BESS

12.1 All grid-connected standalone BESS shall be operated in accordance with the provisions of Gujarat Electricity Grid Code and other applicable Regulations.

12.2 The BESS shall be recognised as a controllable and despatchable resource, capable of both injection and drawl of energy, subject to the purpose for which such BESS is installed and the applicable connectivity, open access, scheduling and commercial settlement framework.

12.3 The operation of BESS shall be guided by the following principles:

a) Grid security and reliability shall have over-riding priority;

b) Optimal utilisation of storage capacity shall be ensured;

c) Compliance with contractual obligations shall be maintained;

d) Efficient participation in electricity markets and ancillary services shall be enabled;

e) For balancing generation & consumption.

13 Scheduling of BESS

13.1 All grid-connected BESS shall be scheduled and despatched by SLDC in accordance with applicable scheduling and despatch procedures in the Gujarat Electricity Grid Code as well as other applicable Orders/ Regulations of the Commission, as amended from time to time.

13.2 For the purpose of scheduling and energy accounting:

a) Charging of BESS shall be treated as drawal of electricity;

b) Discharging of BESS shall be treated as injection of electricity.

Provided that, co-located BESS shall only be charged through associated generating station.

13.3 Scheduling of Generation-linked BESS

13.3.1 Where the BESS is co-located with a generating station, scheduling shall be undertaken as part of the associated generating station, and such BESS shall not be scheduled as a separate entity, subject to provisions of applicable Regulations.

13.3.2 SLDC shall specify detailed procedures for scheduling and energy accounting of co-located BESS, consistent with these Regulations within two months of notifying these Regulations and submit the same to the Commission for the approval.

13.3.3 Such BESS may be utilised for firming, smoothing and time-shifting of renewable energy, subject to compliance with the applicable scheduling and deviation settlement

provisions as per the Regulations notified by the Commission.

13.4 Scheduling of Transmission-linked BESS

13.4.1 BESS deployed as part of the transmission system shall be operated under the control of SLDC.

13.4.2 The SLDC shall make appropriate arrangements for the charging of the BESS, including the determination of the charging schedule and the identification of the source(s) of energy used for such charging, in a manner consistent with grid-security, operational requirements, and the applicable Regulations. However, SLDC shall retain overall supervisory control and may issue over-riding directions during grid contingencies.

13.4.3 For a BESS installed in the network of a transmission licensee, the drawl schedule for charging of BESS and injection schedule for discharge from BESS shall be accounted for in the drawl /dispatch schedule of respective distribution licensee in whose supply area BESS is installed by transmission licensee. The accounting of the charge/ discharge of such BESS shall be maintained and shall be published by SLDC on weekly/monthly basis along with weekly/ monthly State Energy Account Statements on its website.

13.4.4 The SLDC shall maintain a separate pool account to capture and account for all costs incurred in charging the transmission linked BESS, as well as all revenue earned through discharging through transmission linked BESS. Accordingly, the net cost or the net benefit shall be shared between beneficiaries through separate pool account maintained by SLDC. The SLDC shall prepare procedure for sharing of such net cost / benefit, thereof, amongst the beneficiaries and shall submit the procedures for approval of the Commission within one month from the date of notification of this Regulation.

13.4.5 The utilisation of transmission linked BESS shall be aligned with system requirements including congestion management and grid support.

13.5 Scheduling of Distribution-linked BESS

13.5.1 Distribution Licensees shall schedule the BESS for applications such as peak shaving , loss reduction and network management as per the provisions of the applicable Regulations / Codes.

13.5.2 Distribution Licensee shall ensure coordination with SLDC for scheduling and despatch of BESS in line with the provisions of the applicable Regulations / Codes.

13.6 Scheduling of Standalone BESS

13.6.1 Standalone BESS shall be scheduled as independent entities in line with the provisions of applicable Regulations / Codes.

13.6.2 Such BESS shall submit schedules for:

a) Charging;

b) Discharging;

c) Ancillary services, where applicable.

14 Despatch and Control of BESS

14.1 SLDC shall be the responsible for the despatch of all grid-connected BESS.

14.2 Despatch of BESS shall be undertaken considering:

a) System demand-supply balance;

b) Grid frequency and voltage conditions;

c) Congestion in network;

d) Contractual obligations of BESS operators.

15 Energy Accounting and Settlement

15.1 Energy accounting of BESS shall be carried out separately for charging energy and discharged energy and will be carried out as per the applicable Grid Code.

16 Ancillary Services and Grid Supports by BESS

16.1 Subject to these Regulations, BESS may be utilised for providing ancillary services and grid support services in the State, as and when the appropriate Regulations are notified by the Commission.

16.2 BESS shall be eligible to provide fast response services to support grid stability and reliability, including frequency regulation, ramping support, reserve management, voltage support and such other services as may be specified under applicable Regulations or directions issued by the Commission.

16.3 The SLDC, in consultation with STU and Distribution Licensees shall specify eligibility criteria for BESS resources to provide ancillary services, based on technical criteria and operational performance, and submit the same to the Commission for its approval within two months from the date of notification of this Regulations. After approval from the Commission, SLDC shall publish the eligible criteria and registration process for ancillary service providers.

16.4 The SLDC shall prepare a procedure for Scheduling, Metering, Accounting, Settlement, and Commercial mechanisms for the operationalisation of ancillary services, for approval by the Commission, within four months from the date of publication of this Regulation.

16.5 BESS Developer designated or contracted for provision of ancillary services shall comply with despatch instructions issued by SLDC for such services.

16.6 SLDC will have over-riding power regarding scheduling and despatch of BESS in case of grid contingencies or system emergencies.

16.7 BESS Developer may provide ancillary services either as a standalone resource, as part of a generating station, or through aggregation, subject to compliance with technical and operational requirements specified by the SLDC.

16.8 BESS Developer participating in electricity markets shall be compensated based on

market-determined prices.

17 Multi-use and Revenue Framework

17.1 Subject to these Regulations, Standalone BESS may be utilised for multiple applications including:

a) Energy arbitrage;

b) Ancillary services;

c) Peak demand management;

d) Congestion management.

17.2 Where BESS is deployed for multiple uses, operation shall be subject to:

a) Technical feasibility;

b) Contractual obligations;

c) System constraints.

17.3 In case of competing requirements, priority shall be as follows:

a) Grid security and reliability;

b) Ancillary service obligations;

c) Contractual commitments;

d) Market participation.

17.4 Recovery of costs through multiple revenue streams shall be permitted, contractual payments, and market-based revenues.

17.5 Revenues and performance obligations for different services shall be accounted separately to prevent double accounting or double recovery of benefits or liabilities.

17.6 The Commission may, from time to time, enable participation of BESS in emerging market mechanisms including capacity markets, flexibility markets and ancillary service markets, based on system requirements and regulatory developments.

18 Curtailment and Rescheduling of BESS

18.1 SLDC may curtail or reschedule operation of BESS in the interest of:

a) Grid constraint/security;

b) System reliability;

c) Emergency conditions.

18.2 Such directions shall be binding on all BESS operators.

Chapter 4: Technical, Safety, Data & Cybersecurity Framework

19 Technical Standards

19.1 BESS installation shall conform to technical standards specified by the Central Electricity Authority (CEA), Policies and Guidelines issued by the Ministry of Power and MNRE, Govt. of India and other relevant authorities. They shall abide by the relevant Rules and Regulations framed under the Electricity Act, 2003, including the Indian Electricity Grid Code (IEGC), Grid Connectivity Standards, and other relevant Rules/Codes/Procedures issued by the Commission from time to time.

19.2 BESS providers shall submit real-time and periodic data to SLDC in the prescribed format notified by SLDC and approved by the Commission.

19.3 The procedure for first-time charging, testing and commissioning of BESS shall be specified in the Gujarat Electricity Grid Code, as amended from time to time.

20 Safety, Cybersecurity and Environmental Norms

20.1 BESS systems shall comply with Central Electricity Authority (Measures Related to Safety and Electric Supply) Regulations, 2023, as amended time to time and other applicable Standards and Codes.

20.2 The cybersecurity and communication protocols shall adhere to the guidelines of the Ministry of Electronics and Information Technology (MeitY), the Central Electricity Authority (CEA), and the Ministry of Power (MoP),

20.3 Environmental management and end-of-life disposal of batteries shall be in accordance with the Battery Waste Management Rules 2022 or any other guidelines / Regulations of the Government of India / Government of Gujarat as amended time to time. The responsibility of disposal shall lie with the owner of the BESS.

Chapter 5: Miscellaneous

21 Role of Consumers/Prosumers

21.1 All consumers/prosumers, including those availing Net Metering/Gross Metering/ Net Billing/ Group Net Metering/ Virtual Net Metering arrangements, shall be allowed to install a BESS at eligible consumers/prosumers' premises, either as standalone systems or in conjunction with renewable energy sources, with prior approval of the Distribution Licensee or Transmission Licensees, as applicable.

21.2 Such installations shall comply with the applicable technical standards and connectivity requirements specified by the CEA and other relevant Regulations in force. The consumer/prosumer shall register itself with GEDA and take prior permission of distribution licensee / transmission licensee before commissioning the BESS.

21.3 In the event of any deviation from the prescribed technical standards, the same shall be rectified by BESS developer and certified by the concerned Distribution Licensee or State Transmission Utility prior to synchronization with the grid.

Provided that BESS operating in complete isolation from the grid shall not be subject to the above requirements relating to intimation, inspection, or certification.

21.4 Consumers or prosumers with BESS installed under Net Metering/ Gross Metering/ Net Billing/ Group Net Metering/ Virtual Net Metering arrangements shall be permitted to utilise such systems for self-consumption.

22 Role of Aggregator

22.1 Aggregators may aggregate BESS resources from grid-connected standalone storage, from multiple sites to provide services to the SLDC/Transmission Licensees/Distribution Licensees or other market participants.

22.2 Aggregators registered/appointed with/by the Distribution Licensees shall follow the protocols issued by SLDC.

23 Open Access to BESS

23.1 GERC (Terms and Conditions of Intra-State Open Access) Regulations, 2011 and GERC (Terms and Conditions for Green Energy Open Access) Regulations, 2024, as amended from time to time, as applicable, shall govern the open Access and related charges.

24 Dispute Resolution

24.1 All billing related disputes of consumers/prosumers shall be dealt with by the Consumer Grievance Redressal Forum (CGRF). Any other dispute arising under this Regulation that does not fall under the purview of the CGRF shall be adjudicated by the Commission.

25 Power to give directions

25.1 The Commission may, from time to time, issue such directions and orders as it considers appropriate for the implementation of these Regulation.

26 Power to relax

26.1 The Commission may, by general or special order, for reasons to be recorded in writing, and after giving an opportunity of hearing to the parties likely to be affected, may relax any of the provisions of these Regulations on its own motion or on an application made before it by an interested person.

27 Power to amend

27.1 The Commission may, from time to time, add to, vary, alter, suspend, modify, amend, or repeal any provision of these Regulations.

28 Power to remove difficulties

28.1 If any difficulty arises in giving effect to the provisions of these Regulations, the Commission may, by an order, make such provisions, not inconsistent with the provisions of the Act and these Regulations, as may be necessary for removing the difficulty.

Sd/-

Place: Gandhinagar **RANJEETH KUMAR J., IAS**

Date: 12.05.2026 Secretary