Annexures

of

46th ERPC Meeting

of

EASTERN REGIONAL POWER COMMITTEE

Date: 06th August'2022

Time: 14:00 Hrs

Mayfair Tea Resort, Siliguri

Annexure-A

ATTENDANCE SHEET FOR 46TH ERPC MEETING ON 06TH AUGUST 2022

S.N	Name	Designation	Company Name		MOBILE NO:	SIGNATURE
1	MR. S . SURESH KUMAR	ACS , POWER . GOW	POWER DEPT		9999048918	
2	Shri Santanu Basu, IAS	Chief Managing Director	WBSEDCL		9874157619	
3	Dr P.B. Salim, IAS	CMD	WBPDCL		95317 75711	
4	Shri Harish Saran	Executive Director	PTC INDIA LIMITED		9810394429	
5	Shri Sudip Kumar Dash	Head Commercial	MPL		9204652809	
6	Nadeem Ahmad	Electrical Superintending Engineer	BSPHCL		7763814046	
7	Shri Jaganath Sahoo	General Manager (Operation Services) ER-I	NTPC		9416212526	
8	Shri Kallol Sarkar	General Manager (Commercial) ER-I	NTPC		8902 499534	
9	Shri Manish Jain	Additional General Manager (Commercial)	NTPC		9650993492	
10	Shri Pradeep Kumar Mohanty	Head (Electrical)	GMRKEL			
11	Shri Dharmendra Nath Patra	General Manager (Electrical)	OHPC		7328840020	
12	Shri Amiya Kumar Mohanty	General Manager (Electrical)	OHPC		7328840019	
13	Shri U.K. Pati	Director (Operation)	OPTCL		9438902280	
14	Shri Santosh Kumar Das	Deputy General Manager (Electrical)	OPTCL		9438907316	
15	Shri Chitta Ranjan Mishra	Deputy General Manager (Electrical)	OPTCL		9438907305	
16	Shri Manoj Kumar Karmali	Director (Project)	JUSNL		9939583762	
17	Shri Mukesh Kumar Singh	General Manager	SLDC Jharkhand		943015389	
18	Shri D P Bhargava	Managing Director	Teesta Urja Ltd		9958833998	
19	Shri Jaideep Lakhtakia	Executive Director (Power Sales & Regulations)	Teesta Urja Ltd		9810519283	
20	Shri Sanjay Mittal	Director Power Sales	JITPL		9811314080	
21	Shri Shubhang Nandan	Head (Power Sales & Regulatory)	JITPL		8102899777	
22	Shri KMK Prusty	General Manager (O&M)	KBUNL		9004497014	
23	Shri Subhasis Ghosh	Director (O&M)	WBPDCL		9073900831	

ATTENDANCE SHEET FOR 46TH ERPC MEETING ON 06TH AUGUST 2022

I.No	Name	Designation	Company Name		MOBILE NO:	SIGNATURE
24	Shri Kausik Dutta	Executive Director (OS)	WBPDCL		8336903895	
25	Shri V V Shivakumar	General Manager (Commercial) ER-II	NTPC		9447797577	
26	Shri B B Mehta	Director	SLDC Odisha		9879200136	
27	Shri P K Sathpathy	Senior General Manager	SLDC Odisha		9438907410	
28	Shri S C Dash	General Manager	SLDC Odisha		9438907966	
29	Shri Sabyasachi Roy	Director (Operations)	WBSETCL		9434910015	
30	Shri Debashis Chaki	Chief Engineer CPD	WBSETCL		9434910019	
31	Shri Goutam Nayak	Chief Engineer SLDC	WBSETCL		9434910020	
32	Shri Sandip Pal	Vice President (System Operations)	CESC		[illegible]	
33	Shri Arunava Sen Gupta	General Manager (System Operations)	CESC		9831802682	
34	Shri A.K. Maiti	Executive Director	Powergrid		9434740036	
35	PARTHO GHOSH	Chief General Manager	Powergrid		9434748263	
36	Shri Uttam Kumar	Director (Operation)	BSPTCL		9264477220	
37	Shri Satya Narayan Kumar	Chief Engineer (O&M)	BSPTCL		7763817721	
38	Shri Arun Kumar Chaudhury	Chief Engineer (SO)	BSPTCL		7763817733	
39	Shri Nimish Sheth	Chief Operating Officer	DMTCL		7042879619	
40	Shri Umakanta Sahoo	Director (T&BD & Commercial)	GRIDCO			
41	Shri Prashant Kumar Das	Chief General Manager (PP)	GRIDCO		9438907408	
42	Shri Deepak Kumar	Chief Engineer (Commercial)	NBPDCL		9264437178	
43	**Shri Arup Sarkar**	**Member (Finance)**	DVC		9425294115	
44	Shri Jayanta Dutta	Chief Engineer (System Engineering)	DVC		9431515717	
45	Shri Purushottam Prasad	Chief Engineer (Commercial)	SBPDCL		7763814744	
46	Shri Irshad Akhatar	Electrical Executive Engineer (Commercial)	SBPDCL		7763814050	

ATTENDANCE SHEET FOR 46TH ERPC MEETING ON 06TH AUGUST 2022

S.No	Name	Designation	Company Name		MOBILE NO:	SIGNATURE
47	Shri Rajib Sutradhar	Executive Director	ERLDC			
48	Shri Saugato Mondal	Deputy General Manager	ERLDC			
49	Shri Manas Das	Chief Manager	ERLDC		9007070925	
50	Ms. Shabari Pramanick	Manager	ERLDC		9007058764	
51	Shri Abhijeet Kumar	Chief Engineer (PMC)	BSPHCL			
52	Shri K. K. Verma	Chairman, TCC & MD, JUSNL cum Director (D&P)	JUSNL & JBVNL		7004775151	K C Verma 6/8/22
53	Shri Arvind Kumar	Executive Director (C & R)	JBVNL		7004784607	6/8/22
54	Shri Hare Ram Panday	Director(Projects)	BSPTCL		7763817709	
55	N S Mondal	Member Secretary	ERPC			N.S. Mondal
56	S. Kejriwal	Superintending Engineer	ERPC			Kejriwal
57	A. De	Executive Engineer	ERPC		9681932906	alik.erpc@gov.in
58	P P Jena	Executive Engineer	ERPC		9776194991	
59	S K Pradhan	Assitant Executive Engineer	ERPC		8249244719	Sk.pradh[illegible]@gov.in
60	S R Swain	Assitant Engineer	ERPC		9337791451	
61	K Satyam	Assitant Engineer	ERPC		7355225072	
62	A Basu	Assitant Executive Engineer	ERPC/BSPTCL		7070939184	
63	Shri A B Rathod	Chief Engineer SLDC Gujarat	GETCO			
64	Shri Kalyan Kumar Ghosh	FA & CFO	WBSEDCL		9830572512	
65	Shri Abhijeet Latua	Director HR	WBSEDCL			
66	Shri Santanu Sarkar	Chief Engineer, PTP	WBSEDCL		9900793210	
67	DEBASHIS MAJUMDER	DGM	WBPDCL			
68	RAJAT KOLEY	SR. MANAGER	WBPDCL			
69	Sri. Asim Nandi	EXECUTIVE DIRECTOR (COMMERCIAL)	DVC			

REGISTRATION SHEET FOR 46TH ERPC MEETING ON 06TH AUGUST 2022

l.No	Name	Designation	Company Name		MOBILE NO:	SIGNATURE
70	Sri. Subrata Ghosal	Chief Engineer (COMMERCIAL)	DVC		9432677003	
71	Shri Namgyal Tashi	Executive Engineer	Sikkim (SLDC)		7797672743	
72	Shri Ashish Lamichaney	Assistant Engineer	Sikkim(Transmission)		9615878284	
73	Shri Bhanu Sharma	Assistant Engineer	Sikkim (Trading)		7063679856	
74	Shri Somranjan Panda	Superintending Engineer, Regulating Cell	WBSEDCL		9433430100	
75	Shri Partha Saha	Senior Manager (F&A), Fund and Payment Dept	WBSEDCL		7003039751	
76	Shri Surya kant Singh	Manager (F&A), Corp. Compilation	WBSEDCL		9874011899	
77	SHIBESH DEB	CHIEF ENGINEER /HYDEL	WBSEDCL		9339297659	
78	Preetam Banarji	SE	WBSEDCL		7003871109	
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Amar Hill, Saki Vihar Road,
Powai, Mumbai – 400 072
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Fax : +91-22-28571707 / 1913
Email : cnms@chemtrols.co.in
Website: www.chemtrols.com

INDUSTRIES PVT LTD.
(Formerly Known as Chemtrols Engineering Ltd.)

July 6, 2022

Ref: UEX130005/SBU5/ERPC/001/2022

To
The Member Secretary
Eastern Regional Power Committee
14 Golf Club Road
Tollygunge, Kolkata-700033

Sub: Proposal for AMC of RTU and Control Centres under Eastern Region SCADA/EMS Upgradation Project

Ref: Maintenance Contract Ref: CC-CS/326-ER2/EMS-1767/3/G4/CA-III/4635 dated 31.05.2013

Kind Attn. Shri M. S. Mondal

Dear Sir,

With reference to the above subject matter and subsequent discussion had with you along with members of POSOCO, Powergrid and all other constituents during special meeting held at your premises on 14-06-2022, we are pleased to submit our offer for AMC of RTUS (with immediate effect) and also for Control Centre (ERLDC & SLDCs) for additional 2 years (after completion 6years AMC period) as per below mentioned options

Option-1

Offer for AMC of RTU & LDMS AMC (Excluding supply of spares and repairing of hardware) as below

Sl. No.	Min. RTU & LDMS Qty.	Unit	Unit Price Per month	Monthly Total Price	Yearly Total Price
1	20	set	8,400	1,68,000	20,16,000
2	40	set	7,000	2,24,000	26,88,000
3	60	set	5,600	3,13,600	37,63,200
4	80	set	4,480	2,91,200	34,94,400

(All prices are excluding GST)

- Payment shall be made on Quarterly basis including applicable taxes and duties
- Minimum order qty. of RTU & LDMS under proposed AMC as mentioned in the above tables shall be considered.
- AMC of RTU & LDMS shall be considered from 01-07-2022 onwards.
- Quarterly AMC prices of all Control Centre shall remain same. However, replacement of Firewalls and Battery banks shall be excluded from Chemtrols scope
- The Performance Bank Guarantee currently submitted will be reduced to 3% of the value of the extended Contract Amount as per GoI norms
- We request you to release the 10% amount with-held over the duration of the AMC Contract before the commencement of the extension Contract.
- All Other terms and conditions as mentioned in the service contract shall remain same.

Option-2

Sl. No.	Particulars	Unit	Min. Qty.	Unit Price Per Month	Total Price per month	Yearly Total Price
1	AMC of Control Centres	Nos.	9	1,42,796	12,85,164	154,21,968
2	AMC of RTU & LDMS	Set	200	4,000	8,00,000	96,00,000

(All prices are excluding GST)

- AMC of RTU & LDMS shall be excluding supply of spares and repairing of hardware.
- AMC of RTU & LDMS shall be considered from 01-07-2022 onwards.
- Payment shall be made on Quarterly basis including applicable taxes and duties
- Extended (2 years) AMC of Control Centre shall be as per terms and conditions of existing AMC Service Contract. However, revised price as mentioned in the above table shall be applicable
- The Performance Bank Guarantee currently submitted will be reduced to 3% of the value of the extended Contract Amount as per GoI norms
- We request you to release the 10% amount with-held over the duration of the AMC Contract before the commencement of the extension Contract.

Please let us know which option you would like to proceed with. As you are aware, we have been giving RTU maintenance support for over 5 years now without asking for any additional payment, and keeping this also in mind, request your favorable consideration to the options put forward.

We look forward to continuing to work with you over the next few years.

Thanking You,

Yours Sincerely,

Hindol Dhar

(Hindol Dhar)
Sr. Manager

Annexure-B3

EASTERN REGIONAL POWER COMMITTEE

ERPC (CONDUCT OF BUSINESS RULES), 2022

ERPC (TECHNICAL CO-ORDINATION SUB-COMMITTEE) REGULATIONS, 2022

ERPC (OPERATION CO-ORDINATION SUB-COMMITTEE) REGULATIONS, 2022

ERPC (COMMERCIAL SUB-COMMITTEE) REGULATIONS,2022

ERPC (PROTECTION SUB-COMMITTEE) REGULATIONS, 2022

ERPC (TELECOMMUNICATION, SCADA AND TELEMETRY SUBCOMMITTEE) REGULATIONS, 2022

ERPC (TRANSMISSION PLANNING SUB-COMMITTEE REGULATIONS),2022

ERPC (ESTABLISHMENT FUND) REGULATIONS,2022

ERPC FUND REGULATIONS, 2022

KOLKATA

AUGUST 2022

CONTENTS

Eastern Regional Power Committee

(Conduct of Business) Rules, 2022

CHAPTER-I
GENERAL

[Dated: 06th August 2022]

1. Short title and commencement

1.1. Government of India, under the provision of Sub-Section 55 of Section 2 of the Electricity Act 2003 vide Resolution F.No. 23/21/2021-R&R dated 03rd December'2021 and subsequent Corrigendum dated 17th December'2021 published in the Gazette of India (herein after referred to as 'GoI Resolution', attached at Annexure-A) has established the Eastern Regional Power Committee (hereinafter referred to as 'ERPC') comprising of States of West Bengal, Bihar, Orissa, Jharkhand and Sikkim for facilitating the integrated operation of the power systems in the Region.

1.2. Drawing powers from the para (9) of the aforesaid GoI Resolution, the ERPC hereby makes the following rules called "Eastern Regional Power Committee (Conduct of Business) Rules,2022" (hereinafter referred to as 'CBR').

1.3. These rules shall come into force from the date of its approval by the ERPC and shall remain in force unless otherwise modified and shall supersede "Eastern Regional Power Committee (Conduct of Business) Rules, 2011".

2. Definitions:

2.1 In these Rules unless the context otherwise requires:

a) 'Act' means the Electricity Act, 2003.
b) 'Agenda' means the list of business items proposed to be transacted at a meeting of the Committee or Sub-Committee.
c) 'Authority' means Central Electricity Authority (CEA)

d) 'CBR' means 'Eastern Regional Power Committee (Conduct of Business) Rules, 2022'

e) 'Commercial Sub-Committee (CC)' means a sub-committee constituted by the ERPC to consider commercial related issues.

f) 'Commission' means the Central Electricity Regulatory Commission (CERC).

g) 'Committee' means the Eastern Regional Power Committee (ERPC) constituted by the Central Government under Sub-Section (55) of Section 2 of the Act.

h) 'CTU' means Central Transmission Utility.

i) 'ERLDC' means Eastern Regional Load Despatch Centre.

j) 'IEGC' means the Indian Electricity Grid Code regulations by CERC.

k) 'Meeting' means a meeting of the Committee or Sub-Committee convened by the Head of the Secretariat or any member authorized to convene a meeting in the absence of the Head of Secretariat.

l) 'Member' means the member of the ERPC as per GoI Resolution.

m) 'NCT' means National Committee on Transmission

n) 'NLDC' means National Load Despatch Centre.

o) "Non Regular Member" means members who are participating in the meetings of ERPC paying Participation fees.

p) 'NPC' means National Power Committee constituted by MoP, GoI to resolve the issues among RPCs.

q) 'Operation Coordination Sub-Committee (OCC)' means a sub-committee constituted by the ERPC to consider all issues related to operation of the regional grid.

r) 'POSOCO' means Power System Operation Corporation Limited.

s) 'Protection Sub-Committee (PC)' means a sub-committee constituted by the ERPC to consider all power system protection related issues.

t) 'Sub-Committee' means the sub-committee constituted by ERPC to guide and assist it in conducting the functions assigned to it.

u) 'System Study Sub-Committee' means a sub-committee constituted by ERPC to carry out the system studies.

v) 'Technical Coordination Sub-Committee (TCC)' means a sub-committee constituted by the ERPC to assist the ERPC on all technical, commercial and other matters.

w) 'TeST Sub-Committee' means a sub-committee constituted by ERPC to consider all issues related to Telecommunication, SCADA and Telemetry.

x) "Transmission Planning Sub-Committee" means a sub-committee constituted by ERPC to study and give suggestions on the intra-state transmission planning proposals submitted by the state transmission utilities including DVC.

y) "Year" means a financial year.

2.2 The words and expression used and not defined in these Rules shall be construed as having the same meaning as defined in the Act.

3. Functions of ERPC

3.1 Clause 29 (4) of the Act provides that "the Regional Power Committee in the region may, from time to time; agree on matters concerning the stability and smooth operation of the integrated grid and economy and efficiency in the operation of the power system in that region."

3.2 As per Clause-6 of the MoP Resolution dated 3rd December 2021 ERPC shall carry out following functions:

(1) To undertake Regional Level operation analysis for improving grid performance.

(2) To facilitate inter-state/inter-regional transfer of power.

(3) To facilitate all functions of planning relating to inter-state/intra state transmission system with CTU / STU.

(3A) To provide views on the inter-state transmission system planned by CTU within 45 days of the receipt of the proposal by the concerned RPC. The views of RPC will be considered by National Committee on Transmission for sending their recommendation to Ministry of Power for approval of new inter-state transmission system.

(4) To coordinate planning of maintenance of generating machines of various generating companies of the region including those of inter- state generating companies supplying electricity to the Region on annual basis and also to undertake review of maintenance programme on monthly basis.

(5) To undertake planning of outage of transmission system on monthly basis.

(6) To undertake operational planning studies including protection studies for stable operation of the grid.

(7) To undertake planning for maintaining proper voltage through review of reactive compensation requirement through system study committee and monitoring of installed capacitors.

(8) To evolve consensus on all issues relating to economy and efficiency in the operation of power system in the region.

3.3 ERPC shall discharge the functions envisaged in Regulations, IEGC and orders of CERC, CEA Regulations, Orders of MoP, GoI Resolution issued from time to time.

3.4 ERPC may decide any function for itself, from time to time.

4. Chairperson of ERPC

4.1 Para (4) of the GoI Resolution provides**:**

"Chairperson of the ERPC would represent the States of the region by rotation in alphabetical order. Members of the ERPC from the particular State would nominate the Chairperson of ERPC from amongst themselves. The term of the Chairperson would be for a period of one year."

4.2 In the last ERPC meeting of each year, the members of the ERPC belonging to the concerned State shall nominate the Chairperson of the ERPC for the ensuing year, who shall take over the charge w.e.f. 1st April.

4.3 In the event, Chairperson ceases to be a member of the ERPC, and he/she is from a particular State having two or more members, members of ERPC from that State shall consult each other and communicate their nomination for Chairperson of ERPC.

4.4 As per MoP order No. A-60016/59/2005 Adm-I dated 23.02.2006, Member Secretary, ERPC will be under the administrative and financial control of the Chairperson, ERPC.

4.5 The Chairperson, ERPC shall preside over the ERPC meeting.

5. Secretariat of ERPC

5.1 Clause-8 of MoP Resolution dated 3rd December 2021 specifies that:

"The Committee shall have a Secretariat of its own which will be headed by the Member Secretary of the Committee. The Member Secretary as well as other staff for the Secretariat shall be provided by the Central Electricity Authority in the manner as was being provided to the erstwhile Eastern Regional Electricity Board."

5.2 The Secretariat shall be the nodal point for all communications with ERPC.

5.3 The Secretariat shall assist ERPC for discharging all the functions of ERPC.

5.4 The Secretariat shall also discharge functions assigned to it by MoP, CEA and CERC.

5.5 The detailed functions and duties of the Secretariat are appended at Annexure-I.

5.6 Manpower

5.6.1 As per GoI Resolution, "The Committee shall have a secretariat of its own which will be headed by the Member Secretary of the Committee. The Member Secretary as well as other staff for the secretariat shall be provided by the Central Electricity Authority in the manner as was being provided to the erstwhile Eastern Regional Electricity Board".

5.6.2 However, in order to help discharge the duties of ERPC Secretariat, as and when required, officers from State Utilities of ER may be deputed to ERPC Secretariat on loan basis with consent of ERPC Forum.

5.6.3 However, in order to help discharge the duties of ERPC Secretariat, as and when required, Group "C" officials may be outsourced with consent of ERPC Forum.

5.6.4 Member Secretary is also empowered to hire services of personnel as and when required on short-term basis. The same shall be vetted by ERPC Forum in due course.

5.6.5 ERPC may hire experts or consultants for specific assignments. For this purpose, ERPC shall make regulation determining the terms and conditions.

6. Constituents' obligation to furnish data / information to the Secretariat of ERPC

6.1 As per CEA Regulations Grid Standard 2010, clause (15)

(a) All real time operational data as required by the Appropriate Load Despatch Center shall be furnished by the Entities.

(b) All data required by Regional Power Committee, in discharge of the responsibilities assigned to it, shall be furnished by Regional Load Despatch Centre (RLDC).

(c) All operational data, including disturbance recorder and event logger reports, for analyzing the grid incidents and grid disturbance and any other data which in its view can be of help for analyzing grid incident or grid disturbance shall be furnished by all the Entities within twenty-four hours to the Regional Load Despatch Centre and concerned Regional Power Committee.

(d) All equipment such as disturbance recorders and event loggers shall be kept in healthy condition, so that under no condition such important data is lost.

(e) A real time operation display of the grid position shall also be made available to the Regional Power Committee by Regional Load Dispatch Centre.

(f) Regional Load Dispatch Centre shall classify the grid incidents and grid disturbances according to regulation 11, analyse them and furnish periodic reports of grid incidents and grid disturbances to the Regional Power Committee which shall recommend remedial measures to be taken on the Report of Regional Load Despatch Centre to prevent recurrences of such grid incidents and grid disturbances.

6.2 The constituents of the region shall make available to the Secretariat all the data / information required by the Secretariat to discharge all its functions or to carry out any other responsibility/function assigned to it by the Authority/Commission/Committee

7. Website of ERPC

The ERPC website shall be maintained by ERPC Secretariat.

CHAPTER - II

METHODOLOGY TO DISCHARGE THE FUNCTIONS

8. All decisions shall be taken during a meeting of the constituent members called 'ERPC Meeting'. All decisions of ERPC shall be by consensus. Chapter-III deals with the procedure for conducting ERPC Meeting as well as all other Sub-Committee meetings of ERPC.

9. Para (10) of GoI Resolution dated 03.12.2021 and subsequent Corrigendeum dated 17.12.2021 provides:

"The Committee may constitute its Sub-Committees, Task Forces, Ad-hoc Committees and Standing Committees, as deemed necessary for efficient functioning. It may also set up, if required, Groups/ Committees of eminent experts to advise it on issues of specific nature. The level of the representative to the Sub-Committees etc. would depend on the nature of the issue concerned."

10. Wherever a Sub-Committee is constituted to discharge the functions of ERPC on a regular basis, ERPC shall constitute such sub-committee(s) by making a separate regulation.

11. Wherever, Sub-Committees, Task Forces, Ad-hoc Committees and Standing Committees or Committee, Groups/ Committees of eminent experts is constituted to discharge a one-time job; ERPC or Sub-Committee constituted by it, shall constitute it through a resolution passed respectively in ERPC meeting or Sub-Committee meeting.

CHAPTER-III

PROCEDURE FOR CONDUCTING ERPC MEETING

12. Periodicity, Place and date of ERPC Meeting

12.1 The ERPC shall meet at least once in a month, as per Clause-11 of MoP Resolution dated 3rd December 2021 and subsequent Corrigendum dated 17.12.2021.

12.2 Member Secretary, ERPC on its own or a matter referred by CEA/GOI or on a matter proposed by any constituents may convene a meeting on short notice on any urgent matter in consultation with The decision of Member Secretary and Chairperson with regard to degree of urgency shall be binding on all parties concerned.

12.3 The date of the meeting will be decided by Member Secretary, ERPC in consultation with Chairperson, ERPC as well as the host organisation. The place will be decided by Member Secretary, ERPC in consultation with the host organisation.

12.4 In case the situations are not conducive for physical meetings, the meetings may be conducted through Video Conferencing or Hybrid mode(physically as well as virtually).

13. Hosting the ERPC meeting

13.1 Meeting will be hosted by member organizations as per the roster finalized by ERPC. The host member organisation shall incur its expenditure

13.2 ERPC shall determine the terms and procedure for maintaining the roster. The regulations on hosting of ERPC meetings are appended at Annexure-II.

14. Re-scheduling / Cancellation of Meeting

14.1 If a meeting is required to be rescheduled or cancelled, the same shall be intimated to the members at the earliest by telephone/ e-mail and also posted on ERPC Website.

15. Notice for the Committee meeting and Agenda

15.1 Notice for the Committee meeting shall be issued by Member Secretary, ERPC at least three weeks in advance in consultation with Chairperson, ERPC. For urgent meeting (refer 12.2) notice of one week may be given.

15.2 Agenda for Committee meeting shall be put up after discussions in TCC. Every constituent should ensure that it places its agenda item in time. For agenda of TCC meeting, refer the related regulations.

15.3 Agenda pertaining to ERPC Secretariat shall be placed directly before the Committee.

15.4 Member Secretary, ERPC may also put any agenda involving urgent matter/ policy issue directly before the Committee in consultation with Chairperson, ERPC.

15.5 Normally, ERPC shall meet to discuss the agenda related to transmission planning submitted by CTU on monthly basis. Discussions other than those related to transmission planning shall generally be put up after discussions in Technical Coordination Sub-Committee (TCC)

16. Effect of Non-receipt of Notice of Meeting by a Member

16.1 The non-receipt of notice by any member of ERPC or Sub-Committees shall not invalidate the proceeding of the meeting or any decision taken in the meeting.

17. Quorum of ERPC Meeting

17.1 The Quorum of the meeting shall be 50% of its members or the person authorized by the member.

17.2 Only members of ERPC accompanied by not more than two representatives of concerned organization shall participate in the meeting. Additional representatives may participate with prior permission of the Member Secretary.

17.3 Special Invitees by Member Secretary may also attend the meeting

18. Decision making and implementation

18.1 All decisions shall be taken during a meeting of the constituent members called 'ERPC Meeting'. All decisions of ERPC shall be by consensus.

18.2 As per Clause-7 of MoP Resolution dated 3rd December 2021 and subsequent Corrigendum dated 17.12.2021, the decision of the ERPC arrived at for Operation of the Regional Grid and Scheduling and dispatch of Electricity shall be followed by Eastern Regional Load Despatch Centre (ERLDC) subject to the directions of regulations of the Central Commission, if any.

18.3 Each constituent shall follow the decision of ERPC and convey to the ERPC Secretariat the follow up action taken on the decision(s) taken in the previous meeting(s). ERPC Secretariat shall compile the follow up action on the decision(s) and place it before the ERPC. Follow up action shall be omitted for those decisions which have been completely implemented.

19. Presiding Authority and the Convener

19.1 The Chairperson, ERPC shall preside over the meeting of ERPC.

19.2 The Member Secretary, ERPC shall convene the meeting.

19.3 If the Chairperson is unable to be present at the meeting for any reason, ex-Chairperson of the previous year shall preside over the meeting. If ex-Chairperson is not present, then the ERPC members from State Utilities may decide among themselves who will preside over the meeting.

19.4 If the Member Secretary is unable to be present at the meeting for any reason, the next senior most officer of the ERPC Secretariat shall convene the meeting.

20. Recording and finalization of the minutes

20.1 The host organisation shall get the proceedings of the meeting electronically recorded and handover its copy to the Secretariat. The Secretariat shall keep it as record until the minutes of the meeting get confirmed.

20.2 The minutes of the meeting shall be finalized after due approval of Chairperson, ERPC and circulated to all its members by ERPC Secretariat within 15 working days from the date of this meeting. The minutes shall also be posted on the website of ERPC.

21. Confirmation of the Minutes

21.1 Minutes of the ERPC meeting shall be placed in the next meeting for getting confirmed. In case of minutes pertaining to urgent matters, it may be got confirmed by circulation among the members.

CHAPTER-IV

COMPOSITION AND FUNCTIONS OF SUB-COMMITTEE OF ERPC

22. Constitution of Sub-Committee of ERPC

22.1 Following Sub-Committees have been constituted by ERPC to assist it in conducting the functions assigned to it in their respective Regulations:

22.1.1 Technical Co-ordination Sub-Committee (TCC)

22.1.2 Operation Co-ordination Sub-Committee (OCC)

22.1.3 Commercial Sub-Committee (CC)

22.1.4 Protection Co-ordination Sub-Committee (PCC)

22.1.5 Telecommunication, SCADA & Telemetry Sub-Committee (TeST)

22.1.6 Transmission Planning Sub-Committee (TPC)

22.2 Each Sub-Committee shall make a regulation for the procedure for conducting its meetings and get it approved from ERPC. Each Sub- Committee may amend its procedure as and when it requires and get the amendment approved from ERPC.

22.3 Any of these sub-committees can be discontinued through a Resolution of ERPC.

22.4 ERPC may constitute any other sub-committee that it may deem fit through its Resolution.

22.5 TCC Meeting shall be hosted by member organization as per the roster finalized for ERPC meeting. Special TCC meeting, if any, shall be hosted separately by ERPC Secretariat.

CHAPTER-V

EXPENDITURE OF ERPC

23. MoP communication to CEA vide letter no. A-60016/59/2005 Adm-I dated 23rd February 2006 stipulates “The activities of the Regional Power Committees (RPCs) will be fully financed by the constituent Members with effect from 01.04.2006 and the Central Electricity Authority will take immediate steps in this regard.”

24. MoP communication to CEA vide letter no. F.No.6/10/90-Trans dated 3rd April 2006 stipulates “For a transition period of six months the establishment expenditure of RPC would be met out of the budget of the CEA and the same will be reimbursed by the constituent members of the RPCs. Meanwhile, the constituents of RPCs will finalise the share of expenditure to be borne by the constituents of RPCs so that the RPCs become self-financing. The expenditure meted out from the budget and contribution of share by the constituent members will be reviewed by the Ministry of Power, every quarter.”

Unquote (for para 23 & 24): All activities to be self-financed. All expenditures met out of the Central budget shall be reimbursed by the constituent members of ERPC. Any other Establishment related expenditure shall be financed by constituent members of ERPC.

25. For the purpose of reimbursement of expenditures met out of Central Budget to the consolidated fund of GoI, and all other Establishment related expenditure a fund named “ERPC ESTABLISHMENT FUND” has been created and is being maintained by ERPC. Out of this fund, a cheque shall be issued and got deposited to the consolidated fund of GoI for an amount equal to the quarterly bill amount, within the period specified on the bill.

26. As and when CEA/Central Government discontinue the practice of first spending from central budget and getting reimbursement, the all the establishment related expenditure of the ERPC Secretariat shall be met out of “ERPC Establishment Fund”.

27. ERPC shall make regulations on “ERPC Establishment Fund”.

28. The expenses related to ERPC meeting shall be borne by each constituent in respect of the meeting hosted by it (on the basis of roster on its turn).

29. Expenses related to sub-committee meetings and any other meetings/workshops/seminar hosted by ERPC Secretariat shall be met out of the fund named "ERPC FUND", which shall be maintained by ERPC for this purpose. ERPC shall make regulations on "ERPC Fund".

30. Expenses related to activities as a consequence of functions entrusted under IEGC, other regulations / orders of CERC/MoP/CEA shall be met out of the "ERPC Fund" mentioned in para-(29) above.

MEMBER, MEMBER BY ROTATION & CONTRIBUTION

31. Members of ERPC

GoI Resolution dated 03.12.2021 provides for permanent membership and membership of one year by rotation. As per the GoI Resolution the following organisations shall be permanent member of ERPC:

(i) Member (Grid Operation & Distribution), Central Electricity Authority (CEA).

(ii) One representative each of Central Generating Companies, Central Transmission Utility (CTU), Central Government owned Transmission Company, National Load Despatch Centre (NLDC) and the Eastern Regional Load Despatch Centre (ERLDC).

(iii) From each of the States in the region, the State Generating Company, State Transmission Utility (STU), State Load Despatch Centre (SLDC), one of the State owned distribution companies as nominated by the State Government.

(iv) A representative each of every generating company (other than central generating companies or State Government owned generating companies) having more than 1000 MW installed capacity in the region.

(v) A representative each of every Nodal Agency appointed by the Government of India for coordinating cross-border power transactions with the countries having electrical inter-connection with the region.

(vi) Member Secretary, ERPC – Convenor

The representative from respective organizations should be either the head of the organization or at least a person not below the rank of a Director on the Board of the company / corporate entity except for Central Public Sector Undertaking (CPSUs) where representative could also be at the level of Executive Director.

32. Members of ERPC by rotation

The GoI Resolution also provides for membership of ERPC by rotation. The following organizations shall be member of ERPC by rotation for a period of one year.

(i) One distribution company by alphabetical rotation out of the private distribution companies functioning in the region.

(ii) A representative of the generating companies having power plants in the region [not covered in para 3(ii) to 3(iv) of GoI] by alphabetical rotation.

A representative of one private transmission licensee, nominated by Central Government, operating the Inter State Transmission System, by alphabetical rotation out of such Transmission Licensee operating in the region.

(iii) One member representing the electricity traders in the region by alphabetical rotation, which have trading volume of more than 500 million units during the previous financial year.

Wherever a member is represented by rotation, the nomination would be for a period of one year. The level of representation shall be same as is applicable for permanent members.

33. Contribution

(i) All members except CEA, NLDC, CTU and ERLDC shall contribute to 'ERPC Establishment Fund', 'ERPC Fund' and any other fund created by ERPC as per the regulations of respective funds.

(ii) Contributions to the funds for the following year shall be decided by ERPC in its last meeting of the financial year and this decision shall be communicated to all members by ERPC Secretariat.

(iii) All members shall send their contributions in one installment to the ERPC Secretariat within 30 days from the date of communication by ERPC Secretariat failing of which may attract penalty

(iv) All contributions shall be made through any electronic mode.

(v) The contribution of the constituents shall be kept in funds as 'Trustee' until the money is spent for the purpose.

(vi) ERPC shall decide on the deployment of surplus funds from time to time. For this purpose ERPC shall constitute a group of at least three experts in the field of finance and audit from the constituents.

(vii) As per the decision of 33rd ERPC Meeting, Contribution by non-regular member organizations shall be decided by ERPC in its last meeting of the financial year and this decision shall be communicated to all members by ERPC Secretariat.

CHAPTER-VI

REPORTS BY ERPC

SECRETARIAT

34. The following reports shall be prepared and circulated.

Sl. No	Name of the report	Periodicity
1	Monthly Progress Report of Eastern Regional Grid/Operational Data	Monthly
2	Annual Report of ERPC	Annual
3.	Regional Load Generation Balance Reports	Annual + Mid-term
5.	Major Grid incident report	As and when required

CHAPTER-VII

MISCELLANEOUS

35. Saving of inherent Power of the ERPC.

(a) Nothing in these Rules shall bar the ERPC from adopting in conformity with the Act a procedure that is at variance with provisions in these Rules, if the ERPC in view of the special circumstances of a matter or class of matters deem it necessary or expedient to deal with such a matter or class of matters.

(b) Nothing in these Rules shall expressly or by implication, bar the ERPC to deal with any matter or exercise any power under the Act for which no Rules have been framed and ERPC may deal with such matters and functions in a manner it thinks fit.

Annexure-I

FUNCTIONS & DUTIES OF ERPC SECRETARIAT

1. The Secretariat shall perform the following duties namely:

(i) Keep custody of records of proceedings of the Committee, Sub-Committees, Task Force and Working Groups of the ERPC.

(ii) Prepare agenda for the Committee and Sub-Committee meetings.

(iii) Prepare minutes of Committee and Sub-Committee meetings.

(iv) Monitor follow-up action on the decision taken in the Committee & Sub-Committee meeting.

(v) Maintain archive of data and information pertaining to operating parameters, protection system and communication system of the regional power system.

(vi) Collect from the constituent members or other offices, companies, firms or any other party as may be directed by Committee, such information as may be considered useful in the efficient discharge of functions of the Committee under the Resolution and place the information before the Committee and its Sub-Committees.

2. The duties and responsibility envisaged under Indian Electricity Grid Code Regulations (IEGC), other Regulations/Orders of MoP, CEA, CERC Regulations, ERPC Resolutions, GoI Resolution from time to time shall be carried out by the ERPC Secretariat.

3. The functions envisaged for ERPC Secretariat in IEGC Regulations 2010 and subsequent amendments are given below:

(i) **Compliance Oversight:** The RPC in the region shall also continuously monitor the instances of non-compliance of the provisions of IEGC and try to sort out all operational issues and deliberate on the ways in which such cases of non-compliance are prevented in future by building consensus. The Member Secretary RPC may also report any issue that cannot be sorted out at the RPC forum to the Commission. The RPC shall also file monthly reports on

a. Status of UI payment

b. Installation of capacitors by states vis-à-vis the requirement/targets, as decided in the RPC.

(ii) **Reactive Power Compensation:** The person already connected to the grid shall also provide additional reactive compensation as per the quantum and time frame decided by respective RPC in consultation with RLDC. The Users and STUs shall provide information to RPC and RLDC regarding the installation and healthiness of the reactive compensation equipment on regular basis. RPC shall regularly monitor the status in this regard.

(iii) **System Security Aspects:** Any prolonged outage of power system elements of any User/CTU/STU, which is causing or likely to cause danger to the grid or sub-optimal operation of the grid, shall regularly be monitored by RLDC. RLDC shall report such outages to RPC. RPC shall finalize action plan and give instructions to restore such elements in a specified time period.

(iv) **Power System Stabilizer:** Power System Stabilizers (PSS) in AVRs of generating units (wherever provided), shall be got properly tuned by the respective generating unit owner as per a plan prepared for the purpose by the CTU/RPC from time to time.

CTU /RPC will be allowed to carry out checking of PSS and further tuning it, wherever considered necessary.

(v) **Automatic Under Frequency Relay and df/dt relay:** RPC shall decide and intimate the action required by SEB, distribution licensee and STUs to get required load relief from Under Frequency and Df/Dt relays. All SEB, distribution licensee and STUs shall abide by these decisions.

RLDC shall keep a comparative record of expected load relief and actual load relief obtained in Real time system operation. A monthly report on expected load relief vis-a- vis actual load relief shall be sent to the RPC and the CERC.

RLDC shall inform RPC Secretariat about instances when the desired load relief is not obtained through these relays in real time operation.

SLDC shall furnish monthly report of UFR and df/dt relay operation in their respective system to the respective RPC.

RPC Secretariat shall carry out periodic inspection of the underfrequency relays and maintain proper records of the inspection.

(vi) **System Protection Schemes (SPS):** Such schemes would be finalized by the concerned RPC forum and shall always be kept in service.

(vii) **Voltage Control Measures:** All Users, CTU and STUs shall provide adequate voltage control measures through voltage relay as finalized by RPC, to prevent voltage collapse.

(viii) **Procedure for Operational Liaison:** Forced outages of important network elements in the grid shall be closely monitored at the RPC level.

RPC shall send a monthly report of prolonged outage of generators or transmission facilities to the Commission.

(ix) **Outage Planning Process:** The RPC Secretariat shall be primarily responsible for finalization of the annual outage plan for the following financial year by 31st January of each year.

All SEBs/STUs, transmission licensees, CTU, ISGS IPPs, MPPs and other generating stations shall provide RPC Secretariat their proposed outage programme in writing for the next financial year by 30th November of each year.

RPCs shall submit quarterly, half-yearly reports to the Commission indicating deviation in outages from the plan along with reasons .These reports shall also be put up on the RPC website.

(x) **Demarcation of responsibilities:** RLDC shall periodically review the actual deviation from the dispatch and net drawal schedules being issued, to check whether any of the regional entities are indulging in unfair gaming or collusion.

In case any such practice is detected, the matter shall be reported to the Member Secretary, RPC for further investigation/action.

(xi) **Preparation of various Accounts :** RPC Secretariat or any other person as notified by the Commission from time to time, shall prepare monthly Regional Energy Account, Regional Transmission Account, Regional Transmission Deviation Account, Compensation account, Ramping certificate, DC certificate, Security Contraint Economic Despatch account, weekly Deviation Settlement Mechanism account, ancillary services accounts, Reactive Energy account, URS Account and congestion charge account, based on data provided by RLDC/NLDC/ISGS and renewable regulatory charge account based on data provided by SLDC/ RLDC of the State/ Region in which wind generator is located and any other charges specified by the Commission for the purpose of billing and payments of various charges.

(xii) **Transmission System Availability Certificate:** Member Secretary, ERPC shall certify transmission system availability factor for regional AC and HVDC transmission systems separately for the purpose of payment of transmission charges.

Annexure-II

REGULATIONS ON HOSTING OF ERPC MEETINGS

1. As per Clause-11 of MoP Resolution dated 3rd December 2021 and subsequent Corrigendum dated 17.12.2021, ERPC shall meet at least once in a month.
2. Members of ERPC who are members by rotation for a year as per GoI Resolution will not be required to host ERPC meeting [e.g. Member-Trader, Member-IPP (≤1000 MW installed capacity) and Member-Private-DISCOM].
3. The roster for hosting the ERPC meetings shall be in the order as was decided in the 1st meeting of ERPC.

   Final host for a meeting will be decided by Member Secretary, ERPC in consultation with Chairperson, ERPC and shall be announced at the previous meeting. However, Member Secretary, ERPC is empowered to swap the order between two consecutive parties in the list. The roster is as under:

Sl. No.	Host Organization
1.	West Bengal
2.	DVC
3.	NHPC
4.	Power Grid
5.	Sikkim
6.	PTC
7.	Orissa
8.	Jharkhand
9.	Bihar
10.	NTPC
11.	CESC
12.	APNRL
13.	MPL
14.	JITPL
15.	GMRKEL
16.	TPTCL
17.	Teesta Urja Limited
18.	BRBCL
19.	NPGC

4. When the turn for hosting ERPC meeting comes to a State as per above roster, existing members of ERPC from that State (excluding IPPs in the State) shall decide amongst themselves as to who will host the meeting or whether the meeting will be hosted jointly by all members from that State or a group of members.

5. The host organisation shall communicate to the Secretariat about venue, nodal officer, contact telephone no, e-mail id etc.

6. The name of new member of ERPC will be appended to the roster.

Eastern Regional Power Committee

(Technical Co-ordination Sub-Committee) Regulations 2022

[Dated: 6th August 2022]

General

Drawing powers from the para (10) of the GoI Resolution dated 03.12.2021 and subsequent Corrigendum dated 17.12.2021, ERPC hereby makes the following Sub-Committee called "**Technical Co-ordination Sub-Committee**" (hereinafter referred to as '**TCC**').

1. Functions of TCC:

TCC shall consider issues referred to it by the

(a) Operation Co-ordination Sub-Committee

(b) Commercial Sub-Committee

(c) Protection Co-ordination Sub-Committee

(d) Telecommunication, SCADA & Telemetry Sub-Committee (TeST)

(e) Transmission Planning Sub-Committee (TPC)

(f) Other groups/committees/task force constituted by ERPC

(g) Agenda points proposed by the constituents concerning operation of regional grid, commercial aspects, inter-state/inter- regional transfer of power, grid stability etc. leading to economy and efficiency in the operation of power system in the region.

TCC shall consider the matters/issues referred to it by CTU on transmission planning of Eastern Region.

TCC shall also consider the matters/issues referred to it by ERPC.

TCC shall assist to implement the decision of the ERPC and provide guidance on formulation of policy matters on regional grid operation, grid security and commercial matters.

2. Composition of TCC:

2.1 TCC shall comprise of one technical person from each of the ERPC member organizations.

2.2 The TCC members shall be at the level of Member/ Director in State Utilities, and Executive Director/ General Manager in CPSUs, Technical Head of Distribution Company/ Traders/ IPPs, Heads of NLDC & ERLDC, Chief Engineer of CEA and Member Secretary of ERPC.

2.3 Chairperson of TCC shall be nominated by Chairperson, ERPC and shall be from the State, the Chairperson, ERPC represents, for a period concurrent with his/her tenure.

2.4 In the event Chairperson, TCC ceases to be a member of TCC, then Chairperson, ERPC will nominate a new Chairperson.

2.5 In the event of change in the Chairperson, ERPC during a year, the incumbent Chairperson, TCC shall continue.

PROCEDURE FOR CONDUCTING TCC MEETING

3. Periodicity and date of TCC Meeting

3.1 TCC shall normally meet a day before the ERPC meeting.

3.2 TCC may meet separately also as and when needed to address urgent matter which shall be called a special TCC meeting.

3.3 The date of Special TCC meeting will be decided by Member Secretary, ERPC in consultation with Chairperson, TCC.

4. Hosting the TCC meeting

4.1 TCC Meeting will be hosted by member organization as per the roster finalized for ERPC meeting. Special TCC meeting shall be hosted by ERPC Secretariat.

5. Re-scheduling / Cancellation of Meeting

5.1 If a meeting is required to be cancelled or rescheduled, the same shall be intimated to the members at the earliest by telephone / e-mail and also posted on ERPC website.

6. Notice for the Committee meeting and Agenda

6.1 Notice for the TCC meeting shall be issued by Member Secretary, ERPC at least three weeks in advance. Member Secretary, ERPC may convene a Special TCC meeting on short notice on any urgent matter in consultation with Chairperson, TCC.

6.2 Agenda for TCC meeting shall include issues referred to it by various sub-committees, other groups/committees/task force constituted by ERPC, agenda points proposed by constituents, matters/issues referred by CTU.

6.3 Notice may also be issued to non-regular Member organizations of ER to participate in the TCC meeting.

6.4 The agenda points proposed by the constituents for the meeting should reach ERPC Secretariat at least 15 days in advance of the meeting.

6.5 The Member Secretary, ERPC shall finalize the agenda in consultation with Chairperson, TCC and get it posted on the ERPC Website at least 7 days in advance and shall also circulate the agenda to all of its members. Agenda submitted beyond cut-off time as specified shall be posed to Chairperson, TCC for his/her permission. If permitted, it shall be taken up as additional agenda. Agenda submitted after the commencement of the meeting shall not be permitted.

6.6 Member Secretary, ERPC may also put any agenda involving urgent matter/ policy issue directly in consultation with Chairperson, TCC.

7. Effect of Non-receipt of Notice of Meeting by a Member

7.1 The non-receipt of notice by any member of TCC or Sub-Committees shall not invalidate the proceeding of the meeting or any decision taken in the meeting.

8. Quorum of TCC Meeting

8.1 The Quorum of the meeting shall be 50% of its members or the persons authorized by the members.

9. Decision making and implementation

9.1 All decisions in the TCC shall be taken by consensus. TCC shall decide whether its recommendations will be placed before ERPC for approval or information or refer its decisions to sub-committee(s) for implementation.

9.2 ERLDC shall follow the decision of the TCC concerning scheduling, despatch and operation of the regional grid, provided it is consistent with CERC Regulations/orders.

9.3 Each constituent must ensure the implementation of decision taken in the meeting.

9.4 Each constituent should furnish its “action taken report” on the decision taken by TCC in its next meeting as also in subsequent meeting(s) as per requirement.

10. Presiding Authority and the Convener

10.1 The Chairperson, TCC shall preside over the meeting.

10.2 Member Secretary, ERPC shall be the Co-Chairperson of TCC.

10.3 Superintending Engineer, ERPC shall be the convener of the meeting.

10.4 If the Chairperson is unable to be present at the meeting for any reason, Co-Chairperson of TCC shall preside over the meeting. If Co-Chairperson is not present then the members present shall choose a person among themselves, who shall preside over the meeting.

11. Recording of the minutes

11.1 The host organisation shall get the proceedings of the meeting electronically recorded and handover its copy to the Secretariat. The Secretariat shall keep it as record until the minutes of the meeting are got confirmed.

11.2 The minutes of the meeting shall be finalized in consultation with Chairperson, TCC and circulated to all its members by ERPC Secretariat within 15 working days from the date of this meeting. The minutes shall also be posted on the website of ERPC.

12. Confirmation of the minutes

12.1 Minutes of the TCC meeting shall be placed in the next meeting for confirmation. In case of minutes pertaining to urgent matters, it may be got confirmed by circulation.

Eastern Regional Power Committee

(Operation Co-ordination Sub-Committee) Regulations 2022

[Dated: 6th August 2022]

General

Drawing powers from the para (10) of the GoI Resolution dated 03.12.2021 and subsequent Corrigendum dated 17.12.2021, ERPC hereby makes the following Sub-Committee called "**Operation Co-ordination Sub-Committee**" (herein after referred to as '**OCC**')

1. Functions of OCC:

1.1 OCC shall discus all issues related to operation of the regional grid, power supply position of the region, maintenance schedule for generating units and major transmission lines, operation discipline, operation of Automatic Under-Frequency Relays, grid incidents/disturbances, and the status of implementation of the recommendations of the Inquiry Committees, etc.

1.2 OCC shall also discuss any other operational issues as specified in Indian Electricity Grid Code (IEGC) and other CERC regulations.

1.3 OCC shall also deliberate upon any matter as referred by TCC or ERPC.

2. Members of OCC:

2.1 OCC shall comprise of one technical person from each of the member organisation of ERPC. The OCC members shall be at the level of Chief Engineer or equivalent.

2.2 Member Secretary, ERPC shall be the Chairperson of OCC.

2.3 Superintending Engineer (Operation) of Secretariat shall be the convener of OCC.

2.4 Member Secretary, ERPC may co-opt any other person/entity in OCC as special invitee.

PROCEDURE FOR CONDUCTING OCC MEETING

3. **Periodicity, Place and date of OCC Meeting**

    3.1 The meeting will be held at regular interval of about 4 weeks or earlier, as required.

    3.2 The place and date of the meeting will be decided by Member Secretary, ERPC.

4. **Hosting the OCC meeting**

    4.1 In general, The OCC meeting shall be hosted by ERPC Secretariat., However, in special cases the same may be hosted by any other constituents of ER.

5. **Re-scheduling / Cancellation of Meeting**

    5.1 If a meeting is required to be cancelled or rescheduled, the same shall be intimated to the members at the earliest by telephone /e-mail and also posted on ERPC Website.

6. **Notice for the Committee meeting and Agenda**

    6.1 Notice for the Committee meeting shall be issued by Convener at least 10 days in advance.

    6.2 The agenda points proposed by the constituents for the meeting should reach ERPC Secretariat at least 7 days in advance of the meeting. ERPC Secretariat shall finalize the agenda and get it posted on the ERPC Website at least 3 days in advance. Agenda submitted beyond cut-off time as specified shall be posed to Chairperson for his/her permission. If permitted, it shall be taken up as additional agenda. Agenda submitted after the commencement of the meeting shall not be permitted.

    6.3 Member Secretary, ERPC may also put any agenda involving urgent matter/policy issue directly.

    6.4 Notice may also be issued to non-regular Member organizations of ER to participate in the OCC meeting.

7. Effect of Non-receipt of Notice of Meeting by a Member

7.1 The non-receipt of notice by any member of OCC or Sub-Committees shall not invalidate the proceeding of the meeting or any decision taken in the meeting.

8. Quorum of OCC Meeting

8.1. The Quorum of the meeting shall be 50% of its members or the persons authorized by the members.

8.2. Special invitees by Member Secretary may also attend the meeting.

9. Decision making and implementation

9.1. All decisions in the OCC shall be taken by consensus.

9.2. Each constituent must ensure the implementation of the decisions taken in the meeting.

10. Presiding Authority and the Convener

10.1. Member Secretary, ERPC shall preside over the meeting.

10.2. Superintending Engineer ERPC shall convene the meeting.

10.3. If Member Secretary is unable to be present at the meeting for any reason, the next senior most officer of the ERPC Secretariat shall preside over the meeting.

11. Recording of the minutes

11.1. The minutes of the meeting shall be finalized and circulated to all its members by ERPC Secretariat within 10 working days from the date of the meeting. The minutes shall also be posted on the website of ERPC.

12. Confirmation of the Minutes

12.1. Minutes of the OCC meeting shall be placed in the next meeting for confirmation. However, in case of any urgency, the minutes may be confirmed by circulation to the members.

Eastern Regional Power Committee

(Commercial Sub-Committee) Regulations, 2022

[Dated: 6th August 2022]

General

Drawing powers from the para (10) of the GoI Resolution dated 03.12.2021 and subsequent Corrigendum dated 17.12.2021, ERPC hereby makes the following Sub-Committee called "**Commercial Sub-Committee**" (herein after referred to as '**CC**').

1. Functions of CC:

1.1 Commercial Sub-Committee(CC) shall discuss all commercial related issues viz. energy accounting, schemes required for inclusion in the Bulk Power Transmission Agreements, requirement of power from the new projects, installation of special energy meters and its cost sharing, etc., metering aspects, reviewing of the payments towards DSM charges, treatment of transmission losses, commercial declaration of lines/substation, on request from CTUs, commercial issues in inter-state an inter-regional exchange of power, issues concerning settlement of payments among constituents, if any, etc. and any other matter referred by the TCC/ERPC.

2. Composition of Commercial Sub-Committee (CC):

2.1. Commercial Sub-Committee shall comprise of one person (dealing with commercial matters) each from the constituent organisation of ERPC. The CC members shall be at the level of Chief Engineer or equivalent.

2.2. Member Secretary, ERPC shall be Chairperson of the CC.

2.3. Superintending Engineer, ERPC shall be the Convener of the CC.

PROCEDURE FOR CONDUCTING CC MEETING

3. Periodicity, Place and date of CC Meeting

3.1. The meeting will be held at regular interval of about 4 months or earlier, if required.

3.2. The place and date of the meeting will be decided by Member Secretary, ERPC.

4. Hosting the CC meeting

4.1. In general, The CC meeting shall be hosted by ERPC Secretariat. However, in special cases the same may be hosted by any other constituents of ER.

5. Re-scheduling / Cancellation of Meeting

5.1. If a meeting is required to be cancelled or rescheduled, the same shall be intimated to the members at the earliest by telephone / e-mail and also posted on ERPC Website.

6. Notice for the Committee meeting and Agenda

6.1. Notice for the Committee meeting shall be issued by Member Secretary, ERPC at least 15 days in advance.

6.2. The agenda points proposed by the constituents for the meeting should reach ERPC Secretariat at least 10 days in advance of the meeting. ERPC Secretariat shall finalize the agenda and get it posted on the ERPC Website at least 7 days in advance, and shall also circulate the agenda to all of its members. Agenda submitted beyond cut-off time as specified shall be posed to Chairperson for his/her permission. If permitted, it shall be taken up as additional agenda. Agenda submitted after the commencement of the meeting shall not be permitted.

6.3. Member Secretary, ERPC may also put any agenda involving urgent matter/ policy issue directly.

6.4. Member Secretary, ERPC may convene a meeting on short notice on any urgent matter.

6.5. Notice may also be issued to non-regular Member organizations of ER to participate in the CC meeting.

7. Effect of Non-receipt of Notice of Meeting by a Member

7.1. The non-receipt of notice by any member of CC or Sub-Committees shall not invalidate the proceeding of the meeting or any decision taken in the meeting.

8. Quorum of CC Meeting

8.1. The Quorum of the meeting shall be 50% of its members or the persons authorized by the members.

8.2. Special Invitees by Member Secretary may also attend the meeting.

9. Decision making and implementation

9.1. All decision in the CC shall be taken by consensus.

9.2. ERLDC shall follow the decision of the CC concerning scheduling, despatch and operation of the Regional Grid, provided it is consistent with CERC Regulations/ orders.

9.3. Each constituent must ensure the implementation of the decisions taken in the meeting.

9.4. Each constituent should furnish its "action taken report" on the decisions taken by CC in its next meeting as also subsequent meeting(s) as per requirement.

10. Presiding Authority and the Convener

10.1. Member Secretary, ERPC shall preside over the meeting.

10.2. Superintending Engineer, ERPC shall convene the meeting.

10.3. If Member Secretary is unable to be present at the meeting for any reason, the next senior most officer of the ERPC Secretariat shall preside over the meeting.

11. Recording of the minutes

The minutes of the meeting shall be finalized and circulated to all its members by ERPC Secretariat within 10 working days from the date of this meeting. The minutes shall also be posted on the website of ERPC.

12. Confirmation of the Minutes

Minutes of the CC meeting shall be placed in the next meeting for confirmation. However, in case of any urgency, the minutes may be confirmed by circulation to the members.

Eastern Regional Power Committee

(Protection Co-ordination Sub-Committee) Regulations 2022

[Dated: 6th August 2022]

General

Drawing powers from the para (10) of the GoI Resolution dated 03.12.2021 and subsequent Corrigendum dated 17.12.2021, ERPC hereby makes the following Sub-Committee called "**Protection Co-ordination Sub-Committee**" (herein after referred to as '**PCC**').

1. Functions of PCC:

1.1 Protection Co-ordination Sub-Committee (PCC) shall discuss all power system protection related issues viz. analysis of system disturbances in the region, review of protective relaying schemes, relay co-ordination islanding schemes, automatic under frequency, load shedding schemes, review of the implementation of recommendation made by the Inquiry Committee of the grid disturbance in the region concerning the above matters, etc. and any other matter referred by the TCC/ERPC.

2. Composition of Protection Co-ordination Sub-Committee

2.1. Protection Co-ordination Sub-Committee shall comprise of one person each from the constituent organisation of ERPC. The PCC members shall be at the level of Chief Engineer or equivalent and dealing with power system protection / testing.

2.2. Member Secretary, ERPC shall be Chairperson of the PCC.

2.3. Superintending Engineer, ERPC shall be convener of the PCC.

<u>PROCEDURE FOR CONDUCTING PC MEETING</u>

3. Periodicity, Place and date of PC Meeting

3.1. The meeting will be held at regular interval of about 4 weeks or earlier, as required

3.2. The place and date of the meeting will be decided by Member Secretary, ERPC.

4. Hosting the PCC meeting

4.1. In general, The PCC meeting shall be hosted by ERPC Secretariat. However, in special cases the same may be hosted by any other constituents of ER.

5. Re-scheduling / Cancellation of Meeting

5.1. If a meeting is required to be cancelled or rescheduled, the same shall be intimated to the members at the earliest by telephone / e-mail and also posted on ERPC Website immediately.

6. Notice for the Committee meeting and Agenda

6.1. Notice for the Committee meeting shall be issued by Member Secretary, ERPC at least 15 days in advance.

6.2. The agenda points proposed by the constituents for the meeting should reach ERPC Secretariat at least 10 days in advance of the meeting. ERPC Secretariat shall finalize the agenda and get it posted on the ERPC Website at least 5 days in advance, and shall also circulate the agenda to all of its members. Agenda submitted beyond cut-off time as specified shall be posed to Chairperson for his/her permission. If permitted, it shall be taken up as additional agenda. Agenda submitted after the commencement of the meeting shall not be permitted.

6.3. Member Secretary, ERPC may also put any agenda involving urgent matter/ policy issue directly.

6.4. Member Secretary, ERPC may convene a meeting on short notice on any urgent matter.

6.5. Notice may also be issued to non-regular Member organizations of ER to participate in the PCC meeting, as and when required.

7. Effect of Non-receipt of Notice of Meeting by a Member

7.1. The non-receipt of notice by any member of PC shall not invalidate the proceeding of the meeting or any decision taken in the meeting.

8. Quorum of PCC Meeting

8.1. The Quorum of the meeting shall be 50% of its members or the persons authorized by the members.

8.2. Special Invitees by Member Secretary may also attend the meeting.

9. Decision making and implementation

9.1. All decisions in the PCC shall be taken by consensus.

9.2. ERLDC shall follow the decisions of the PC concerning Protection Coordination, Analysis of grid incidences and Disturbance report preparation, etc. of the Regional Grid, provided it is consistent with CERC Regulations/orders.

9.3. Each constituent should ensure the implementation of the decisions taken in the meeting.

9.4. Each constituent should furnish its “action taken report” on the decision taken by PC in its next meeting, as also subsequent meeting(s) as per requirement.

10. Presiding Authority and the Convener

10.1. Member Secretary, ERPC shall preside over the meeting.

10.2. Superintending Engineer, ERPC shall convene the meeting.

10.3. If Member Secretary is unable to be present at the meeting for any reason, the next senior most officer of the ERPC Secretariat shall preside over the meeting.

11. Recording of the minutes

The minutes of the meeting shall be finalized and circulated to all its members by ERPC Secretariat within 15 working days from the date of this meeting. The minutes shall also be posted on the website of ERPC.

12. Confirmation of the Minutes

Minutes of the PC meeting shall be placed in the next meeting for confirmation. However, in case of urgency the minutes may be confirmed by circulation to the members.

Eastern Regional Power Committee

(Telecommunication, SCADA & Telemetry Sub-Committee) Regulations 2022

[Dated: 6th August 2022]

General

Drawing powers from the para (10) of the GoI Resolution dated 03.12.2021 and subsequent Corrigendum dated 17.12.2021, ERPC hereby makes the following Sub-Committee called "**Telecommunication, SCADA & Telemetry Sub-Committee**" (herein after referred to as '**TeST**').

1. **Functions of TeST:**

   1.1 TeST Sub-Committee shall meet to deliberate upon Telecommunication, SCADA and Telemetry schemes of ER and issues thereon in accordance with the provisions of Indian Electricity Grid Code.

2. **Composition of Telecommunication, SCADA & Telemetry Sub-Committee:**

   2.1. Telecommunication, SCADA & Telemetry Sub-Committee shall comprise of one person each from the constituent organisation of ERPC. The TeST members shall be at the level of Chief Engineer or equivalent and conversant with Telecommunication, SCADA & Telemetry in the region.

   2.2. Member Secretary, ERPC shall be Chairperson of the TeST.

   2.3. Superintending Engineer of Secretariat shall be convener of the TeST.

<u>PROCEDURE FOR CONDUCTING TeST MEETING</u>

3. **Periodicity, Place and date of TeST Meeting**

   3.1. The meeting will be held at regular interval of about 4 months or earlier, if required.

   3.2. The place and date of the meeting will be decided by Member Secretary, ERPC.

4. Hosting the TeST meeting

4.1. In general, The TeST meeting shall be hosted by ERPC Secretariat. However, in special cases the same may be hosted by any other constituents of ER.

5. Re-scheduling / Cancellation of Meeting

5.1. If a meeting is required to be cancelled or rescheduled, the same shall be intimated to the members at the earliest by telephone / e-mail and also posted on ERPC Website immediately.

6. Notice for the Committee meeting and Agenda

6.1. Notice for the Committee meeting shall be issued by Member Secretary, ERPC at least 15 days in advance.

6.2. The agenda points proposed by the constituents for the meeting should reach ERPC Secretariat at least 10 days in advance of the meeting. ERPC Secretariat shall finalize the agenda and get it posted on the ERPC Website at least 5 days in advance and shall also circulate the agenda to all of its members. Agenda submitted beyond cut-off time as specified shall be posed to Chairperson for his/her permission. If permitted, it shall be taken up as additional agenda. Agenda submitted after the commencement of the meeting shall not be permitted.

6.3. Member Secretary, ERPC may also put any agenda involving urgent matter/policy issue directly.

6.4. Member Secretary, ERPC may convene a meeting on short notice on any urgent matter.

6.5. Notice may also be issued to non-regular Member organizations of ER to participate in the TeST meeting, as and when required.

7. **Effect of Non-receipt of Notice of Meeting by a Member**

7.1. The non-receipt of notice by any member of TeST shall not invalidate the proceeding of the meeting or any decision taken in the meeting.

8. **Quorum of TeST Meeting**

8.1. The Quorum of the meeting shall be 50% of its members or the persons authorized by the members.

8.2. Special Invitees by Member Secretary may also attend the meeting.

9. **Decision making and implementation**

9.1. All decisions in the TeST shall be taken by consensus.

9.2. ERLDC shall follow the decisions of the TeST, provided it is consistent with CERC Regulations/orders.

9.3. Each constituent should ensure the implementation of the decisions taken in the meeting.

9.4. Each constituent should furnish its "action taken report" on the decision taken by TeST in its next meeting, as also subsequent meeting(s) as per requirement.

10. **Presiding Authority and the Convener**

10.1. Member Secretary, ERPC shall preside over the meeting.

10.2. Superintending Engineer, ERPC shall convene the meeting.

10.3. If Member Secretary is unable to be present at the meeting for any reason, the next senior most officer of the ERPC Secretariat shall preside over the meeting.

11. Recording of the minutes

The minutes of the meeting shall be finalized and circulated to all its members by ERPC Secretariat within 15 working days from the date of this meeting. The minutes shall also be posted on the website of ERPC.

12. Confirmation of the Minutes

Minutes of the TeST meeting shall be placed in the next meeting for confirmation. However, in case of urgency, the minutes may be confirmed by circulation to the member

Eastern Regional Power Committee

(Transmission Planning Sub-Committee) Regulations 2022

[Dated: 6th August 2022]

General

Drawing powers from the para (10) of the GoI Resolution dated 03.12.2021 and subsequent Corrigendum dated 17.12.2021, ERPC hereby makes the following Sub-Committee called "**Transmission Planning Sub-Committee**" (herein after referred to as '**TPC**').

1. Functions of TPC:

1.1 Transmission Planning Sub-Committee (TPC) shall study and give suggestions on the intra-state transmission planning proposals submitted by the state transmission utilities including DVC.

2. Composition of Transmission Planning Sub-Committee (TPC) Sub-Committee:

2.1. Transmission Planning Sub-Committee shall comprise of members from each of the state transmission utilities, SLDCs, DVC, CTU, ERLDC & ERPC Secretariat. The TPC members shall be at the level of Chief Engineer or equivalent.

2.2. Member Secretary, ERPC shall be Chairperson of the TPC.

2.3. Superintending Engineer, ERPC shall be convener of the TPC.

<u>PROCEDURE FOR CONDUCTING TPC MEETING</u>

3. Periodicity, Place and date of TPC Meeting

3.1. The meeting will be held as and when required.

3.2. The place and date of the meeting will be decided by Member Secretary, ERPC.

4. Hosting the TPC meeting

4.1. The TPC meeting shall be hosted by ERPC Secretariat, Kolkata.

5. Re-scheduling / Cancellation of Meeting

5.1. If a meeting is required to be cancelled or rescheduled, the same shall be intimated to the members at the earliest by telephone / e-mail and also posted on ERPC Website immediately.

6. Notice for the Committee meeting and Agenda

6.1. Notice for the Committee meeting shall be issued by Member Secretary, ERPC at least 15 days in advance.

6.2. The agenda points proposed by the constituents for the meeting should reach ERPC Secretariat at least 10 days in advance of the meeting. ERPC Secretariat shall finalize the agenda and get it posted on the ERPC Website at least 5 days in advance and shall also circulate the agenda to all of its members. Agenda submitted beyond cut-off time as specified shall be posed to Chairperson for his/her permission. If permitted, it shall be taken up as additional agenda.

6.3. Agenda submitted after the commencement of the meeting shall not be permitted.

6.4. Member Secretary, ERPC may also put any agenda involving urgent matter/ policy issue directly.

6.5. Member Secretary, ERPC may convene a meeting on short notice on any urgent matter.

6.6. Notice may also be issued to non-regular Member organizations of ER to participate in the TPC meeting, as and when required.

7. Effect of Non-receipt of Notice of Meeting by a Member

7.1. The non-receipt of notice by any member of TPC shall not invalidate the proceeding of the meeting or any decision taken in the meeting.

8. Quorum of TPC Meeting

8.1. The Quorum of the meeting shall be 50% of its members or the persons authorized by the members.

8.2. Special Invitees by Member Secretary may also attend the meeting.

9. Decision making and implementation

9.1. All decisions in the TPC shall be taken by consensus.

9.2. Each concerned constituent should ensure the implementation of the decisions taken in the meeting.

9.3. Each concerned constituent should furnish its "action taken report" on the decision taken by TPC in its next meeting, as also subsequent meeting(s) as per requirement.

10. Presiding Authority and the Convener

10.1. Member Secretary, ERPC shall preside over the meeting.

10.2. Superintending Engineer, ERPC shall convene the meeting.

10.3. If Member Secretary is unable to be present at the meeting for any reason, the next senior most officer of the ERPC Secretariat shall preside over the meeting.

11. Recording of the minutes

The minutes of the meeting shall be finalized and circulated to all its members by ERPC Secretariat within 15 working days from the date of this meeting. The minutes shall also be posted on the website of ERPC.

12. Confirmation of the Minutes

Minutes of the TPC meeting shall be placed in the next meeting for confirmation. However, in case of urgency, the minutes may be confirmed by circulation to the members

ERPC (ESTABLISHMENT FUND) REGULATIONS-2022

[Dated: 6th August 2022]

Drawing power from section 25(d) of 'Eastern Regional Power Committee (Conduct of Business) Rules, 2022', ERPC hereby makes the following regulations called "**ERPC (Establishment Fund) Regulations 2011**".

1. **Name:** The name of the fund shall be "**ERPC Establishment Fund**".

2. **Objective:** The fund shall be utilized for meeting reimbursement of expenditure met out of Central Budget to the consolidated fund of GoI, and all other Establishment related expenditure.

3. **Contribution:** All members of ERPC except CEA, NLDC, CTU and ERLDC shall contribute equal amount on annual basis as per the decision of ERPC. Members of ERPC shall send their contribution through any electronic mode. Besides, all non-regular members, participating in the meetings of ERPC shall contribute Participation Fee, on annual basis as per the decision of ERPC.

4. **Operation:** The fund shall be operated by a group of three officers from member constituents of ERPC, preferably posted in Kolkata as nominated by Member Secretary, ERPC. Bank account shall be opened in the name of the fund in a scheduled bank and officers nominated as above shall be given the cheque drawing authority. The maximum tenure of each nominated officer will be three years. The tenure of any nominated officer can be further extended at the sole discretion of Member Secretary, ERPC.

5. The actual expenditure met out of Central Budget for the relevant period as approved by Member Secretary, ERPC shall be reimbursed to the consolidated fund of GoI by cheque drawn in favor of 'DDO, ERPC, Kolkata'.

6. Audited yearly statement of receipt & expenditure of the fund shall be placed before the ERPC.

7. ERPC Secretariat shall place the head wise budget estimate for the next financial year before the ERPC forum in the last ERPC meeting of the current financial year for approval.

8. Expenditure against approved budget, as per para (7), can be made with the approval of Member Secretary, ERPC.

9. The fund shall be audited by Chartered Accountant.

10. The accounts of the fund shall be got audited by two officers, one officer nominated by incumbent Chairperson from his own organisation & the other nominated by the Chairperson of previous year from his own organisation. The officers nominated as above shall be other than the officers nominated as per para-4 above.

11. ERPC, if desires, may constitute a Sub-Committee, comprising of at least three experts in the field of finance and audit from the constituents to discuss/ settle/ recommend on various issues related to this fund.

12. Management of surplus fund shall be at the sole discretion of ERPC. Expenditure from the surplus funds shall be made only after the consent of ERPC.

ERPC FUND REGULATIONS-2022

[Dated: 6th August 2022]

Drawing power from section 28 of 'Eastern Regional Power Committee (Conduct of Business) Rules, 2022', ERPC hereby makes the following regulations called "**ERPC Fund Regulations 2022**".

1. **Name:** The name of the fund shall be **"ERPC Fund".**

2. **Objective:** The fund shall be utilised for

   (i) Expenses related to meetings, workshops, seminars etc. hosted by ERPC Secretariat.
   (ii) Expenses related to hospitality extended to officials of constituents and other guests on their visit to ERPC Secretariat.
   (iii) Expenses related to printing and binding works for flex/banner, publication of reports etc.
   (iv) Expenses related to discharge of any other functions deemed fit by ERPC.

3. **Contribution:** All members and non-regular members of ERPC except CEA, NLDC, CTU and ERLDC shall contribute equal amount on annual basis as per the decision of ERPC. Members of ERPC shall send their contribution through any electronic mode.

4. **Operation:** The fund shall be operated by a group of three officers from member constituents of ERPC preferably posted in Kolkata as nominated by Member Secretary, ERPC. Bank account shall be opened in the name of the fund in a scheduled bank and officers nominated as above shall be given the cheque drawing authority. The maximum tenure of each nominated officer will be three years. The tenure of any nominated officer can be further extended at the sole discretion of Member Secretary, ERPC.

5. Expenditure from ERPC Fund can be made with the approval of Member Secretary, ERPC.

6. Audited Yearly statement of receipt & expenditure of the fund shall be placed before the ERPC.

7. The fund shall be audited by Chartered Accountant.

8. The accounts of the fund shall be got audited by two officers, one officer nominated by incumbent Chairperson from his own organisation and the other nominated by the Chairperson of previous year from his own organisation. The officers nominated as above shall be other than the officers nominated as per para-4 above.

9. ERPC, if desires, may constitute a Sub-Committee, comprising of at least three experts in the field of finance and audit from the constituents to discuss/ settle/ recommend on various issues related to this fund.

10. Management of surplus fund shall be at the sole discretion of ERPC. Expenditure from the surplus funds shall be made only after the consent of ERPC.

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Annexure-C1

Technical minimum schedule support to ISGS plants of Eastern Region by availing URS power of surrendered beneficiaries

As per the earlier practice, thermal ISGS stations were provided with Technical Minimum schedule support by RLDC, whenever sum of requisition from all the beneficiaries fell below technical minimum, by is jacking up the beneficiary schedule to ensure technical minimum schedule to the generators.

However, in the light of CERC Order on Petition No: 60/MP/2019, the practice of jacking up surrendered schedule of beneficiaries by RLDC was withdrawn in Eastern Region w.e.f 01.02.2022, except in cases as mandated in Section 5.7 of detailed Reserve Shutdown Procedure (RSD) (CERC Order No. - L-1/219/2017-CERC), which states:

Quote

RLDC shall Suo-moto revise the schedule of any generating station as per clauses 6.5.14 and 6.5.20 of the Grid Code to operate at or above technical minimum in the ratio of under-requisitioned quantum (with respect to technical minimum) in the interest of smooth system operation under the following conditions:

- ✓ *Extreme variation in Weather Conditions*
- ✓ *High Load Forecast*
- ✓ *To maintain reserves on regional or all India basis*
- ✓ *Network Congestion*
- ✓ *Any other event which in the opinion of RLDC/NLDC shall affect the grid security.*

While doing so, it is possible that the requisition of some beneficiaries may go up to ensure technical minimum. In this case, SLDCs may surrender power from some other inter-State generating station(s) or intra-State generating station(s) based on merit order. The concerned RLDC shall issue R-1 schedule accordingly and this shall be intimated to the concerned generating station, through the scheduling process."

Unquote.

The methodology evolved in the working committee meeting for giving Technical minimum schedule support to ISGS plants of Eastern Region by availing URS power of surrendered beneficiaries was approved in the 45th ERPC meeting held on 26.03.2022. The methodology adopted in ER is as follows:

Working arrangement for commercial settlement of transfer of URS from one constituent to another constituent

(i) Existing URS Methodology as per regulatory provisions:

a) The un-requisitioned surplus left over in a station can be availed by the beneficiaries requiring power more than their entitlement.

b) The surplus power of one or more beneficiaries of the stations is apportioned to one or more availing beneficiaries on pro rata distribution

c) The surrendering beneficiary does not pay the Fixed Charge (FC) of its surplus share availed by the beneficiary/beneficiaries. The availing beneficiary/beneficiaries pay the FC of the station of the surplus power availed by them.

d) During off peak period, the stations are not getting the Technical Minimum Schedule because of not qualifying in Merit Order Dispatch (MoD) of beneficiaries & opting for RSD. Once the station goes under RSD, the station at many times is not available during the peak period. Thus, the beneficiaries who badly need power are not getting the power due to station under RSD. Also, the FC of the Station under RSD has to be borne by beneficiaries.

e) Therefore, in Eastern Region, it is proposed to utilise the URS power effectively and efficiently, the brief summary of the idea/scheme is as follows:

Methodology Approved in 45th ERPC meeting for Technical minimum schedule support to ISGS plants of Eastern Region by availing URS power of surrendered beneficiaries.

a. Waiver of Fixed Cost for Scheduling up to technical minimum: All the ER constituents namely West Bengal, Odisha, Bihar, Jharkhand, DVC & Sikkim agreed for 100% FC waive off for the URS availed by the availing beneficiary/beneficiaries up to Technical Minimum.

b. NTPC will continuously display the cost of the URS Power available at the discounted rate up to the Technical Minimum of the ISGS stations. Beneficiaries participating in the scheme shall avail the URS power based on their Merit order Dispatch.

c. Post facto Commercial settlement will be done by NTPC and beneficiaries participating in the scheme.

d. This methodology is applicable for Eastern Region beneficiaries only.

In line with the methodology approved in 45th ERPC meeting held on 26.03.2022, NTPC has developed the Technical Minimum software for Easter Region-URJA [URS Re-Scheduling and Jacking-Up Assistant] in co-ordination with ERLDC and ERPC. **The same has been implemented in Eastern Region w.e.f. 15.04.2022.**

Annexure-C3

220kV Bus Bar Protection status at BSPTCL

Sl. no.	Name of the GSS	Status	Remarks
01	Fatuha	GE make Bus Bar Panel available at site. Its commissioning work is pending as one of the relay found defective during panels testing. Relay replacement and further commissioning work to be done by agency.	Continuous follow up from site is needed.
02	Khagaul	Bus Bar Protection Panel not available. One main one transfer bus scheme.	New installation and commissioning is needed.
03	Biharsharif	• Installation and commissioning of new Bus Bar Protection Panel was awarded to M/s GE in 2015, but work remained partially completed and executing agency left midway. • At present 18 no of 220kV bays are available which cannot be integrated in existing Bus Bar Protection Relays. • Also, suitable space is not available in cable trench.	• As per service engineer of m/s GE following modification in old Bus Bar scheme is needed. a) Scheme modification b) Hardware modification c) Software modification d) Firmware modification. • Suitable space in cable trench also needed.
04	Dehri	Bus Bar Panel not available. One main one transfer bus scheme.	New installation and commissioning is needed.
05	Bodhgaya	Bus Bar Panel not available. One main one transfer bus scheme.	New installation and commissioning is needed.
06	Sampatchak	• ABB make Electromechanical type Bus Bar Panel available but not in service due to cases of mal operation. • An estimate for new bus bar scheme prepared and submitted, as per field officials. • Fault Data extraction facility not available in present scheme.	Retrofitting with Numerical type Bus Bar Relay or change of complete Bus Bar Panel is needed for Proper Data Extraction and Fault Analysis
07	Begusarai	ABB make Electromechanical type Bus Bar Panel available but not in service. Fault	Retrofitting with Numerical type Bus Bar Relay or

		Data extraction facility not available in present scheme.	change of complete Bus Bar Panel is needed for Proper Data Extraction and Fault Analysis
08	Bihta new	Alstom make Bus Bar Protection scheme available. Not in service since 28.08.21 due to repeated operation of Y phase Bus Bar Relay. Matter communicated to OEM for rectification of Y phase relay.	Defective relay needs to be replaced to take the Bus Bar Protection system in service
09	Pusauli	ERL make numerical type Bus Bar Protection panel available, but out of service due to mal operation just after commissioning of the GSS.	As it is not working properly since its commissioning in 2015, thorough inspection from OEM is needed.
10	Gopalganj	• As reported, Bus Bar Protection panel was not working properly after its commissioning in 2005. • Easun make **Digital type** Bus Bar Panel available but out of service. Fault Data extraction facility not available.	Retrofitting with Numerical type Bus Bar Relay or change of complete Bus Bar Panel is needed for Proper Data Extraction and Fault Analysis
11	Hajipur	• ABB make **Electromechanical type** Bus Bar panel available but out of service since 03 nos. GSS Bays of BGCL commissioned in same switchyard in 2016. • Fault Data extraction facility not available in present scheme.	Retrofitting with Numerical type Bus Bar Relay or change of complete Bus Bar Panel is needed for Proper Data Extraction and Fault Analysis
12	Darbhanga	• As reported, Bus Bar Protection Panel was not working properly after its commissioning in 2006. • Easun make **Digital type** Bus Bar Panel available but out of service. Fault Data extraction facility not available.	Retrofitting with Numerical type Bus Bar Relay or change of complete Bus Bar Panel is needed for Proper Data Extraction and Fault Analysis
13	Sonenagar NEW	Working	Bus Bar Protection testing done in July 2021 for integration of 220/132 kV 160 MVA ICT.
14	Motipur	Working	
15	Musahari	Working	

16	Khagaria new	Working	Bus Bar Protection testing done on 18/01/22 for integration of 220kV Saharsa New (PGCIL) d/c bays
17	Kisanganj new	Working	Bus Bar Protection testing done on 05/03/22 for integration of 220kV Thakurganj (u/c) d/c bays
18	Madhepura	**Not** Working	• Existing Bus Bar scheme has 04 nos. of bays. • 06 nos. of bays not integrated. • Electromechanical type Bus Bar scheme, fault Data extraction facility not available.
19	Laukahi	Working	

Present Status of Busbar Protection for 220 KV System of OPTCL					
Name of Substation	**Relay Make**	**Relay Model**	**Numerical/Static**	**Busbar Status**	**Remarks**
400/220/132/33 KV Mendhasal	SIEMENS	7SS5231-5CA01-0AA1/HH	Numerical	Healthy	
220/132/33 KV Atri	ALSTOM	BCU-P40 AGILE,P743; MCU-P40 AGILE,P741	Numerical	Healthy	
220/132/33 KV Chandaka-B	SIEMENS	MICOM P741	Numerical	Healthy	
220/132/33kV Goda	GE	B-90	Numerical	Healthy	
220/132/33 KV Balasore	SIEMENS	SIPROTEC 7SS52	Numerical	Healthy	
400/220/33 KV New Duburi	SIEMENS	SIPROTEC 7SS52	Numerical	Healthy	
220/132/33 KV Duburi Old	SIEMENS	SIPROTEC 7SS52	Numerical	Healthy	
220/132/33 KV Joda	SIEMENS	SIPROTEC 7SS52	Numerical	Healthy	
220/132/33 KV Kesinga	SCHNEIDER	MCU-MICOM P741;BCU-MICOM P43	Numerical	Healthy	
220/132/33 KV Jayapatna	GE	B90 Multiline	Numerical	Healthy	
220/132/33 KV Bhanjanagar	SIEMENS	SIPROTEC 7SS52	Numerical	Healthy	
220/132/33 KV Aska New	ALSTOM	MVAJM	Numerical	Healthy	
220/132/33 KV Bargarh New	GE	B90 Multiline	Numerical	Healthy	
220/132/33 KV Nayagarh					Not Available. New Numerical Relay will be commissioned.
220/132/33 KV Samangara	SIEMENS	SIPROTEC 7SS52	Numerical	Unhealthy	01no. Bay Unit (Bus Coupler) is defective. 220kV power supply is not available due to breakdown of D/C Lines during cyclone.
220/132/33 KV Chandaka	SIEMENS	SIPROTEC 7SS52	Numerical	Unhealthy	02nos. Bay Units are defective. M/s SIEMENS is not responding to the call.
220/132/33 KV Cuttack	SIEMENS	SIPROTEC 7SS5251	Numerical	Unhealthy	01no. Bay Unit is defective & sent to SIEMENS Factory for repair.
220/132/33 KV Bidanasi	SIEMENS	SIPROTEC 7SS52	Numerical	Unhealthy	02nos. Bay Units are defective. M/s SIEMENS has been contacted for rectification.
220/132/33 KV Paradeep	ALSTOM	BCU-P40 AGILE,P743; MCU-P40 AGILE,P741	Numerical	Not Commissioned	Will be commissioned during ongoing SAS Project.
220/33 KV Rengali	ER	B3, B24H2	Electromagnetic	Defunct	To be replaced by Numerical Relay
400/220/132/33 KV Meramundali	SIEMENS	SIPROTEC 7SS52	Numerical	Unhealthy	Central Unit & 01no. Bay Unit are defective.M/s SIEMENS has been contacted for rectification.
220/132/33 KV Bhadrak	AREVA	P141	Numerical	Defunct	To be replaced by Numerical Relay.
220/132/33 KV Bolangir New	ABB	REB500	Numerical	Not Commissioned	To be replaced by Numerical Relay of new version.
220/132/33 KV Narendrapur	SIEMENS	SIPROTEC 7SS52	Numerical	Unhealthy	01no. Bay Unit is defective.M/s SIEMENS has been contacted for rectification.

Name of Substation	Relay Make	Relay Model	Numerical/Static	Busbar Status	Remarks
400/220/132/33 KV Lapanga	SIEMENS	SIPROTEC 7SS52	Numerical	Not Commissioned	Will be Commissioned after procurement of CT Primary links for higher CT Ratio.
220/132/33 KV Katapalli	ABB	REB500	Numerical	Not Commissioned	To be replaced by Numerical Relay of new version.
220/132/33 KV Budhipadar	SIEMENS	SIPROTEC 7SS52	Numerical	Unhealthy	03nos. Bay Units are defective.M/s SIEMENS has been contacted for rectification.
220/132 KV Tarkera	SIEMENS	SIPROTEC 7SS52	Numerical	Unhealthy	03nos. Bay Units are defective.M/s SIEMENS has been contacted for rectification.
220/132/33 KV Jayanagar	SIEMENS	SIPROTEC 7SS52	Numerical	Unhealthy	01no. Bay Unit is defective.M/s SIEMENS has been contacted for rectification.
220/132/33 KV Therubali	SIEMENS	SIPROTEC 7SS52	Numerical	Unhealthy	03nos. Bay Units are defective.M/s SIEMENS has been contacted for rectification.
220/33 KV Infocity-2	SIEMENS	SIPROTEC 7SS54	Numerical	Healthy	
220/33 KV Narsinghpur	GE	B90 Multiline	Numerical	Healthy	
220/33 KV Ranki/ Keonjhar	TOSHIBA	GRB200	Numerical	Healthy	
220/33 KV Barkote	ALSTOM	FAC34RF111B	Electromechanical	Not Commissioned	To be replaced by Numerical Relay of new version.
220/33 KV Bonai	GE	B30 Multiline	Numerical	Not Commissioned	To be replaced by Numerical Relay of new version.
220/33 KV Malkangiri	SIEMENS	SIPROTEC 7SS52	Numerical	Healthy	
220/33 KV Balimela	ABB	SPAE 010	Static	Defunct	To be replaced by Numerical Relay of new version.
220/33 KV Kashipur	GE	B90 Multiline	Numerical	Unhealthy	Central Unit & 01no. Bay Unit are defective.M/s GE has been contacted for rectification.
220/33 KV Laxmipur	SCHNEIDER	MICOM P741	Numerical	Unhealthy	01no. Communication Cable of Bay Unit is defective.

Present Status of Busbar Protection for 220 KV System (JUSNL)

Name of Substation	Relay Make	Relay Model	Numerical/Static	Busbar Status	Remarks
220/132KV Hatia-II GSS	Siemens	SIPROTEC 7SS525	Numerical	Working	
220/132/33 KV Burmu (Ratu) GSS	ABB	REB670	Numerical	Working	
220/132KV Dumka-II (Madanpur) GSS	Schendier (MiCOM)	MiCOM P743(Bay Unit) MiCOMP741(Central Unit)	Numerical	Working	
220/132/33 KV Godda GSS	ZIV	Central Unit-DBC Bay Unit-DBP	Numerical	Working	
220/132/33 KV Jasidih GSS	ZIV	Central Unit-DBC Bay Unit-DBP	Numerical	Working	
220/132/33 KV Giridih GSS	Siemens	SIPROTEC 7SS85	Numerical	Working	
220/132/33 KV Lalmatia GSS	N/A				Single main bus With transfer bus
220/132 KV Chandil GSS	N/A				Single main bus With transfer bus
220/132KV Ramchanderpur GSS	GE	Multilin B90	Numerical	Working	Spurious operation of busbar protection was observed in recent past. The scheme requires detail checking.
220/132KV Chaibasa-II GSS (Ulijhari)	Schendier (MiCOM)	MiCOM P743(Bay Unit) MiCOM P741(Central Unit)	Numerical	Working	During 3rd party protection audit, busbar protection is found to be not in operation due to issue in peripheral unit.
220/132KV Bhagodih (Garhwa New) GSS	ZIV	Central Unit-DBC Bay Unit-DBP	Numerical	Working	
220/132/33 KV PTPS Switchyard	N/A				All the 220KV Bays will be shifted to 400/220KV PTPS_New GSS
220/132/33 KV Govidpur GSS	ZIV	Central Unit-DBC Bay Unit-DBP	Numerical	Working	
220/132/33 KV Itakhori GSS	ZIV	Central Unit-DBC Bay Unit-DBP	Numerical	Working	

Present Busbar Protection Status of 220 KV System under WBSETCL

Name of Substation	Relay Make	Type	Numerical/Static	Status	Remarks
Alipurduyar 220 KV	Siemens	7SS52	Numerical	Functional	
New Jalpaiguri 220 KV	Abb	RADSS	Static	Functional	
Dalkhola 220 KV	Abb	RADHA	Static	Functional	
Gazole 220 KV	Siemens	7SS85	Numerical	Functional	
Gokarna 400 KV	Abb	REB670	Numerical	Static relay replacing by Numerical	Expected to be put into service with in May-22
Rejinagar 220 KV	Alstom	Micom P741/743	Numerical	Functional	
Sagardighi 220 KV	ZIV	DBC/DBP	Numerical	Functional	
Jeerat 400 KV	Abb	REB670	Numerical	Functional	
Dharampur 220 KV	Alstom	Micom P746	Numerical	Functional	
Krishnanagar 220 KV	Areva	FAC34	Static	Functional	
Kasba 220 KV	Abb	REB670	Numerical	Functional	
KLC 220 KV	Abb	REB670	Numerical	Functional	
NewTown 220 KV	Abb	RADHA	Static	Functional	
Barasat 220 KV	Siemens	7SS85	Numerical	Functional	
Subhasgram 220 KV	Areva	FAC34	Static	Functional	
Laxmikantapur 220 KV	Abb	REB670	Numerical	Functional	
New Haldia 220 KV	Abb	RADHA	Static	Functional	
Domjur 220 KV	Abb	RADHA	Static	Functional	
Foundry Park 220 KV	Siemens	7SS52	Numerical	Functional	
Howrah 220 KV	Areva	FAC34	Static	Functional	
Rishra 220 KV	Abb	RADHA	Static	Functional	
Chanditala 400 KV	Alstom	Micom P741/743	Numerical	Functional	
Midnapore 220 KV	Abb	RADHA	Static	Functional	
Kharagpur 400 KV	Alstom	Micom P741/743	Numerical	Functional	
Vidyasagar Park 220 KV	Alstom	MFAC34	Static	Functional	
Egra 220 KV	Siemens	7SS85	Numerical	Functional	
New Bishnupur 220 KV	Abb	REB670	Numerical	Functional	
Arambag 400 KV	Abb	REB670	Numerical	Work in progress	Expected to be put into service with in April--22
Satgachia 220 KV	Abb	REB670	Numerical	Static relay replacing by Numerical	Expected to be put into service with in May-22
Durgapur 220 KV	Abb	REB670	Numerical	Functional	
Sadaipur 220 KV	Abb	REB670	Numerical	Functional	
Asansol 220 KV	Abb	RADHA	Static	Functional	
Hura 220 KV	Siemens	7SS52	Numerical	Functional	

Report of the Technical Committee on "Patna & Ranchi Islanding Scheme"

Background:

In the meeting held on 28th December 2020 and chaired by the Hon'ble Minister of State (IC) it was directed that islanding schemes should be implemented for all major cities of the country considering all the strategic and essential loads. Subsequently, in line with the direction given in the meeting, the subject matter was discussed in PCC meeting of ERPC and it was finalized that new islanding scheme would be implemented for capital cities of Patna & Ranchi.

Initially it was decided that Patna Islanding Scheme would be designed considering one unit of NPGCL and corresponding loads of Patna City whereas for Ranchi Islanding Scheme, it was decided to consider one unit of TVNL as participating generator with corresponding loads of Ranchi city.

The matter was discussed in several OCC meetings as well as in 44th & 45th TCC Meeting of ERPC. In 45th TCC meeting, it was decided to constitute technical committee for finalizing the Patna & Ranchi Islanding Scheme.

Accordingly, the committee was formed consisting of members from concerned utilities.

The committee further co-opted members from CESC to the Committee.

The 1st meeting of the committee was held on 19.04.2022 & subsequently three more meetings were held to decide the Islanding schemes.

Discussion & Recommendation of the committee:

<u>Ranchi Islanding Scheme:</u>

In 191st OCC meeting of ERPC held on 20.05.2022, a proposal was approved to charge the existing 220 kV Tenughat-PTPS S/C line at 400 kV level & terminate the line at 400 kV PVUNL S/s for supplying start up power to PVUNL. The new line will be 400 kV Tenughat-PVUNL S/C line. It emerged that after implementation of the above proposal, there will not be any connectivity between the participating generator (Tenughat) and Load centre of Ranchi.

In the 3rd meeting of the committee, Jharkhand representative informed that the above arrangement is an interim one & 400 kV Tenughat-PVUNL line will be later on shifted from PVUNL to 400 kV PTPS S/s after commissioning of PVUNL units (tentatively in 2023). However, they did not communicate any firm timeline for this interim arrangement.

As the timeline of interim arrangement as well as the final network configuration is not clearly spelt out, members opined that the discussion related to Ranchi Islanding Scheme may be kept in abeyance.

Accordingly, it was decided that discussion on Ranchi Islanding Scheme is possible only after finalization of the network configuration.

Patna Islanding Scheme:

The islanding scheme would be designed considering one unit of NPGCL (660 MW) as participating generator & corresponding load Patna city (approx. 560 MW).

Islanding Logic

Based on the preliminary study result of Patna Islanding scheme, the scheme is found to be stable for all the extreme scenarios. The dynamic study report of the Patna Islanding scheme is enclosed at Annexure-B.

The islanding logic is proposed as follows:

I. As the islanding should commence before picking up of any of the under-frequency protection stage of units and that's why island formation will start at 48.4 Hz with a delay of 200 msec.

II. In scenario where Generation is minimum, Loads are becoming High in the island in both the cases of Minimum & Maximum load, so to tackle this situation and avoid fast frequency dip as well as to limit the rate of frequency down following should be done at the instant of island formation,

   Whenever Load >80 MW of Generation, Trip 50 MW between (48.5- 48.7 Hz).

   Whenever Load >150 MW of Generation, Trip 150 MW between (48.5- 48.7 Hz).

III. **Even after that island will be load rich for the case when generation is minimum, In this case, Under frequency Load Shedding (UFLS) inside the island is proposed** to trigger at 48.2 Hz so as to balance the load generation within the island.
   The details are as follows:

   - 48.2 HZ 100 ms 20 % of island load.
   - 48.0 Hz 100 ms 10% of Island load.
   - 47.8 Hz 100 ms 10 % of Island load.

Centralized monitoring and control unit

- As per the preliminary study, **Centralized island monitoring and control unit** needs to be incorporated for continuous monitoring of load and generation balance in the island. It is necessary to maintain the load generation balance within the island for island stability and desired UFLS within the island needs to be implemented as per the final logic decided in line with the study.
- Redundant communication from centralized unit to all feeders needs to be ensured without any delay.
- Apart from centralized unit command which will be sent to the UFLS feeders as well as breakers that need to be tripped for island formation (400 kV as well below voltage level), Stage-wise local UFLS scheme also needs to be ensured to make the system more redundant and full proof.
- Healthiness of all UFLS feeders inside the island also needs to be monitored by a centralized scheme.
- The centralized scheme should have test mode along with arming and disarming mode to ensure that mock testing can be performed without actual breaker tripping by ensuring communication/command signals are reaching the last mile.

- Scheme should be using the existing relays capability to maximum and should have enough redundancy at each level to ensure its successful operation.
- Scheme design should be done also considering in case of any failure of one main control unit, the backup controller should be live and in armed condition.

Action to be taken at Generator side

- NPGCL to decide about the scheme regarding unit selection during islanding as it will require tripping of breakers to create the island. This requires flexibility based on selection of units with one and half scheme bus arrangement. It should be noted that islanding should not be unit specific and should work even with one unit in service during actual conditions.
- NPGC must ensure that during islanding, islanded unit auxiliary or any AC connection between existing units and islanded units should not be there as it will create a loop with the grid.
- NPGC to check regarding capability and feasibility of its units for islanded mode of operation with OEM.

Load Generation balance within island

- In addition to centralised monitoring unit, Provision for monitoring of load generation balance of the system shall be done at NPGCL end as well as SLDC Bihar end.
- Based on the load generation imbalance, corrective action such as necessary pre-identified block load shedding is to be done via centralized unit between 48.8 Hz i.e., last grid side UFR stage setting & 48.4 Hz which is frequency for island formation. This way Island survival and stability can be assured.
- For the above, block of loads /feeders needs to be pre-identified which will be tripped by centralized unit command in between the frequency (48.7-48.5 Hz), in case of large load generation imbalance as per the logic obtained from the study.
- Whenever frequency is below 48.8 Hz (Last STAGE of grid side UFLS) and above islanding frequency (48.4 Hz) and hovering around the same even after some block load shedding by the centralized island monitoring and control system, load generation imbalance can be minimized manually also to stabilize the frequency by SLDC on regular basis. This can be done using alarm system integration for SLDC operators.
- Identified maximum load within the island is to be reviewed periodically. In case of load within the island is exceeding the maximum load considered for the study, it needs to be revised and limited accordingly for successful island formation and its survival.

Finally, the islanding study should be done in detail considering all plant dynamics and various control loops of the plant considering influences from speed and pressure control loop which needs to be studied in consultation with OEM. Scheme detailed engineering design for actual installation and implementation should be done considering reliability, security, selectivity, robustness and redundancy.

****

PATNA ISLANDING STUDY

Introduction:

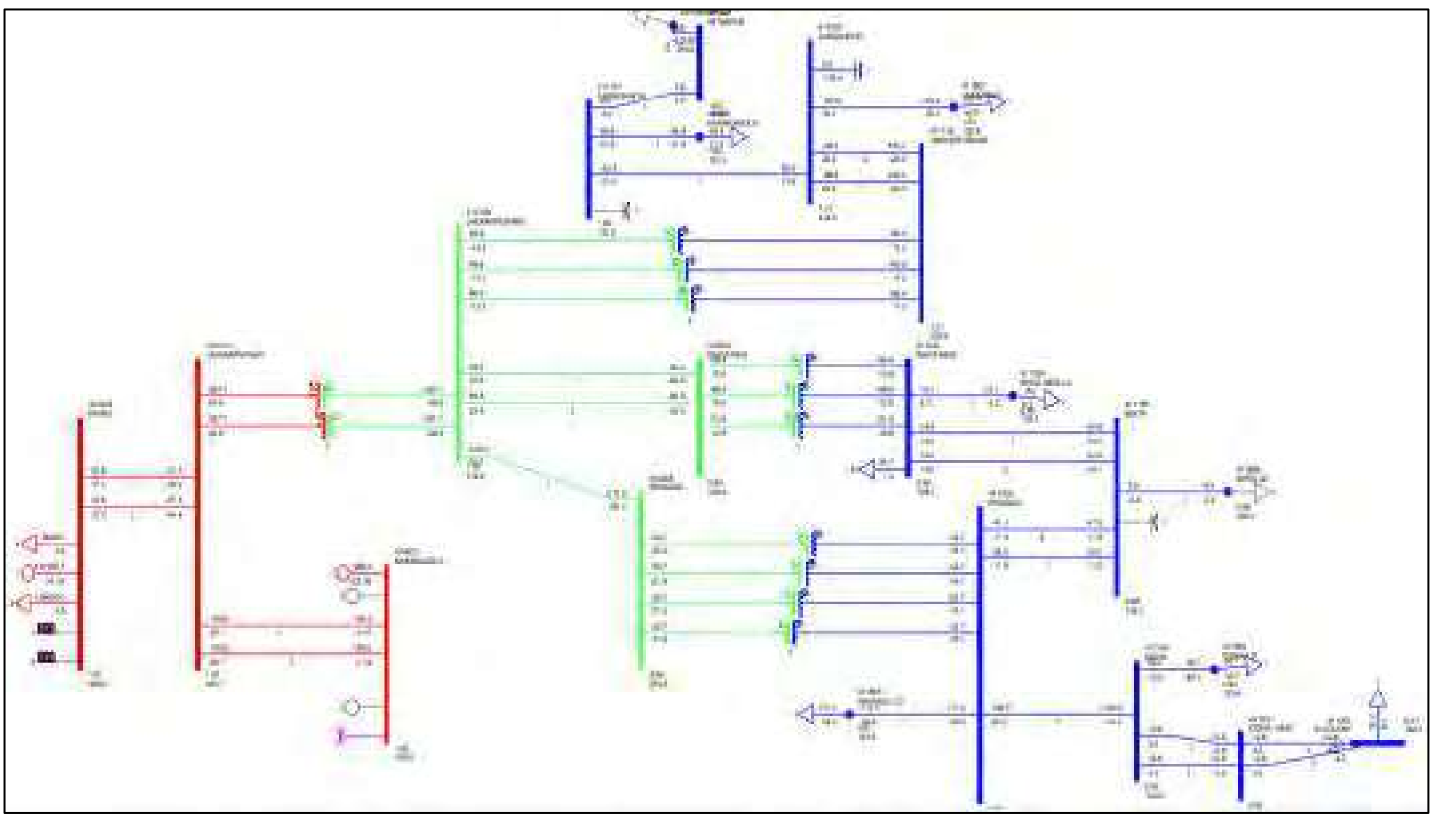
One of the key features of a resilient power system is robust islanding scheme. Success of an islanding scheme depends on the design as well as implementation of the logic. Logic needs to be robust as well as simple. Extensive study is required to design an effective islanding scheme. For PATNA islanding scheme design various preliminary studies are done and the results are discussed below. However, these studies are done based on certain assumption (which will be discussed below) and its purpose is to check the broader feasibility of an islanding scheme. Hence the final islanding logic must be finalized by the respective generating plants in consultation with their OEM.

1. Modeling:

A. Network:

Network modeling data is taken from latest PSSE base case as shared by BIHAR SLDC. Only the part of BIHAR network which corresponds to the Island to be formed, is taken into consideration. Rest of the grid is modeled as an equivalent generator or load.

In one of the equivalent generator bus (400 KV PATNA Bus) two loads are added: 1) Load 1 is a negative load and used for creating the frequency disturbance during the dynamic simulation. 2) Load 2 is All India load.



B. Generator:

NPGC generators are modeled as "GENROU" (cylindrical rotor synchronous machine) based on the OCC magnetization curve. The parameters of "GENROU" are populated based on the generator data sheet.

	Con Value	Con Description
1	5.2600	T'do (> 0)
2	0.0210	T''do (> 0)
3	0.6600	T'qo (> 0)
4	0.0330	T''qo (> 0)
5	2.6500	H, Inertia
6	0.0000	D, Speed Damping
7	2.0300	Xd
8	1.9800	Xq
9	0.3000	X'd
10	0.5000	X'q
11	0.2400	X''d = X''q
12	0.1500	Xl
13	0.0290	S(1.0)
14	0.1700	S(1.2)

Figure 1: NPGC generator parameters.

The equivalent generator representing the All-India grid is modeled by a simple classical cylindrical rotor **"GENCLS" model and its Inertia value** is used as per the inertia calculated during real frequency excursion event in the grid.

C. Exciter and PSS:

The NPGC excitation system is represented by ST7C model of PSSE library along with that PSS2B is used.

	Con Value	Con Description
1	0.0200	TR - regulator input filter time constant (s)
2	1.0000	TG - lead time constant of voltage input (s)
3	1.0000	TF - lag time constant of voltage input (s)
4	1.1000	VMAX - voltage reference maximum limit (p.u.)
5	0.9000	VMIN - voltage reference minimum limit (p.u.)
6	43.8400	KPA (>0) - voltage regulator gain (p.u.)
7	5.1580	VRMAX - voltage regulator maximum limit (p.u.)
8	-5.1580	VRMIN - voltage regulator minimum limit (p.u.)
9	0.0000	KH - feedback gain (p.u.)
10	1.0000	KL - feedback gain (p.u.)
11	1.0000	TC - lead time constant of voltage regulator (s)
12	1.0000	TB - lag time constant of voltage regulator (s)
13	1.0000	KIA (>0) - gain of the first order feedback block (p.u.)
14	3.0000	TIA (>0) - time constant of the first order feedback block
15	0.0000	TA (>0) - thyristor bridge firing control time constant (s)

Figure 2: NPGC exciter model

D. Governor model:

TGOV1 governor model is used and following parameters are considered in simulation:

	Con Value	Con Description
1	0.0500	R
2	0.1000	T1 (>0)(sec)
3	0.8930	V MAX
4	0.4667	V MIN
5	2.0000	T2 (sec)
6	11.0000	T3 (>0)(sec)
7	0.0000	Dt

Figure 3: NPGC governor Model

However, the above model doesn't take for the RGMO and maximum output limit is limited to 5% of current generation value for maximum governor output.

During few simulation the lower limit of the governor is not restricted to 5% of MCR , the reason is as follows:

We know that there is a speed controller in generator, which starts unloading the unit even beyond the 5% limit of RGMO when speed crosses some value and speed controller takes over the load controller.

Also HP-LP bypass system is there for quick load reduction.

E. Load modeling:

Loads are modeled as below:

Real Power: 100% Constant Current

Reactive Power: 100% Constant Admittance

Frequency dependency of the load is not modeled.

2. Design logic:

Following points are considered in designing the islanding logic:

I. Frequency setting for last stage of the existing All-India UFLS scheme is 48.8 HZ; therefore island formation should happen below this frequency with sufficient margin.

II. However, during few scenarios after the formation of the island, island may be generation deficit. To tackle such some UFLS scheme is designed for island. But this UFLS scheme starts much below the grid side UFLS scheme.

III. Present frequency protection setting for NPGC units is as follows:

Under Frequency: 47.4 Hz, 2sec
Over frequency: 52 Hz, 2 sec Only Alarm No tripping, but mechanical side speed related tripping of turbine is there. (At what frequency corresponding to turbine speed ,tripping is there needs to be given by plant)

Based on the above inputs following islanding logic is proposed:

I. Islanding should commence before picking up of any of the under-frequency protection stage of units and that's why island formation will start at 48.4 Hz with a delay of as minimum as possible.

II. In scenario where Generation is minimum, Loads are becoming High in the island in both the cases of Minimum & Maximum load, so to tackle this situation and avoid fast frequency dip as well as to limit the rate of frequency down following should be done at the instant of island formation,

Whenever Load >80 MW of Generation, Trip 50 MW at the instant of island formation at (48.4 Hz).
Whenever Load >150 MW of Generation, Trip 150 MW at the instant of island formation at (48.4 Hz).

III. **Even after that island will be load rich in case of minimum generation so Under frequency inside the island is proposed** to trigger at 48.2 Hz.

The details are as follows

- 48.2 HZ 100 ms 20 % of island load .
- 48.0 Hz 100 ms 10% of Island load.
- 47.8 Hz 100 ms 10 % of Island load.

3. Load Generation Scenario:

GSS	Peak Load(MW)	Off peak load(MW)
Jakkanpur	100	75
Karbigahiya	80	45
Mithapur	60	50
Khagaul	170	150
Bihta(Old)	116	90
Bihta(New)	15.5	10
Digha	95	60
Jakkanpur(new)		
Digha(New)		
Board colony		
Total in MW	**636.5**	**480**
Mithapur AUFLS	50	50
After deducting AUFLS LOAD	**586.5**	430
Railway	11	5
After deducting RAILWAY LOAD	**575.5**	**425**
Additional margin for 220 Khagul line loading	20	5
Island load	**555**	**420**
Final Island load with NPGC Load	**555+80=(635-640 MW) (Max Load),** (80 MW) is auxiliary and other necessary load of NPGC**.**	**420+80=500 MW (Min load)**
Generation Of NPGC	**MAX Generation = 660 MW**	**Min Generation = (380 MW) for meeting Tech Minimum Ex bus .**

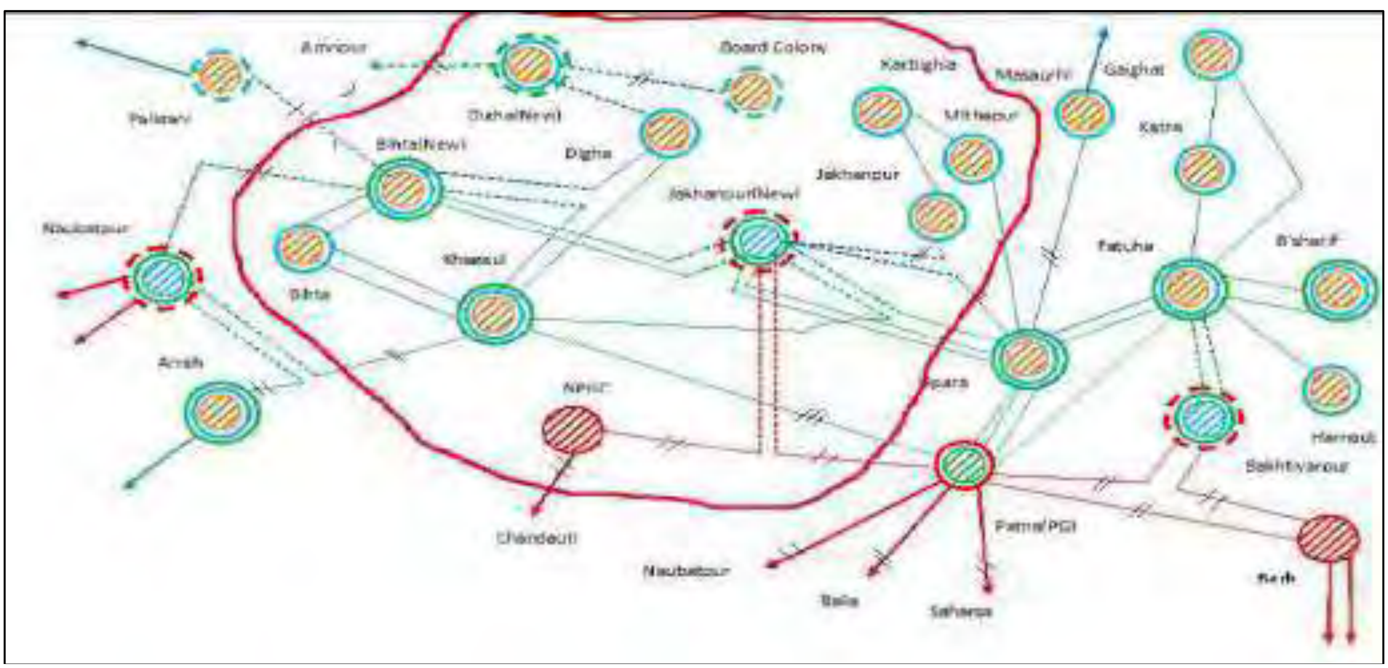


Figure (4) Geographically marked Islanded area

4 Simulation:

Different LGB scenario is studied in the simulation for checking the robustness of the proposed scheme. Details of different scenario are summarized as follows:

Scenario	Generation	Load	Surplus(+)/Deficit(-)
Scenario-1	660 MW (Max Generation)	640 MW (Max Load)	20 MW
Scenario-2	660 MW (Max Generation)	500 MW (Min Load)	160 MW
Scenario-3	380 MW (Min Generation)	500 MW (Min Load)	-120 MW
Scenario-4	380 MW (Min Generation)	640 MW (Max Load)	-260 MW

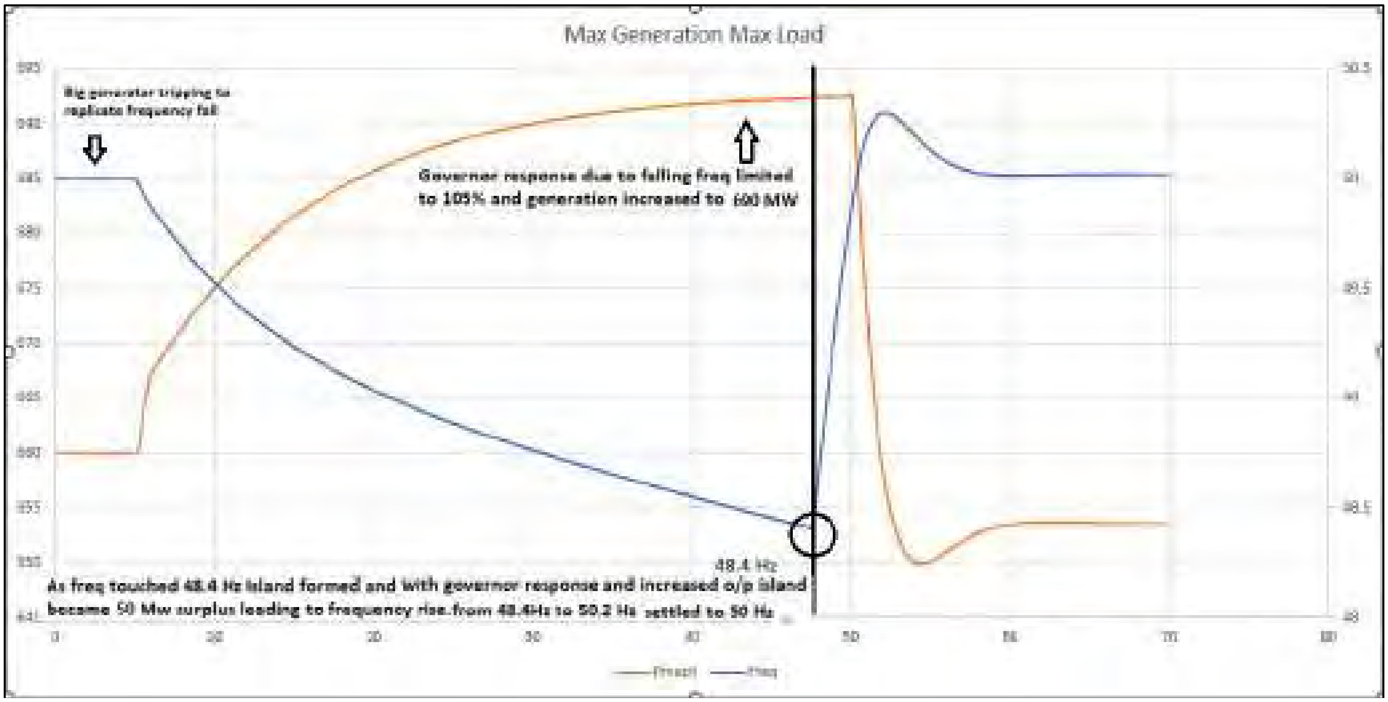
The above LGB is prepared based on input from SLDC.

With above islanding logic following steps are followed:

Step-1. First a grid disturbance is created by tripping 8000 MW generation (i.e. the negative load). This triggers the island formation logic in which the equivalent generator or load buses are tripped, as the frequency drops to 48.4 Hz Island is formed.

Step-2. After formation of island the simulation is further carried out for 60 sec to check stabilization of the island frequency with all generator protection and island UFLS in action.

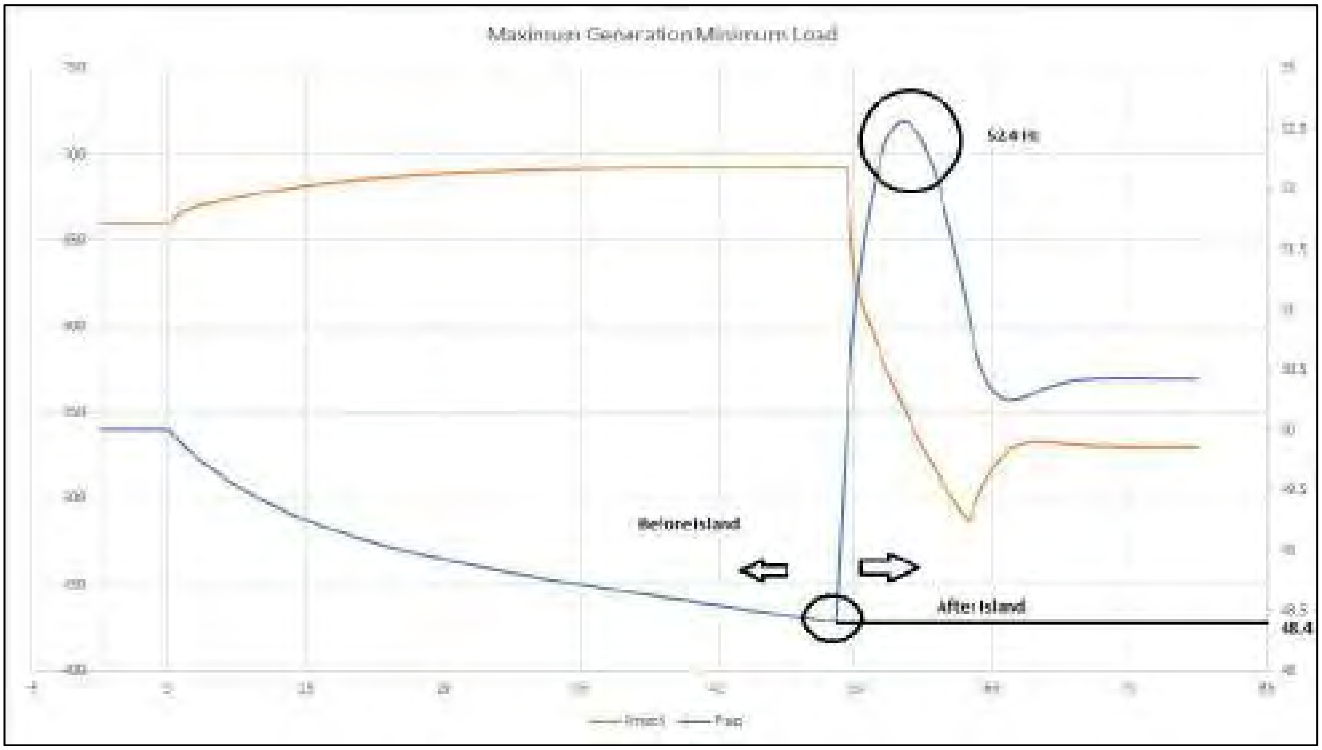
Scenario-1: Maximum generation & Maximum load



Discussion:

1. In max generation max load scenario there is 20 MW surplus generation inside the Island.
2. As the one big generator tripped to replicate frequency fall, Unit of NPGC will also respond to this frequency change and which is limited to 105% of the generation so generation increased till 690MW from 660 MW.
3. As the frequency touches 48.4 Hz and island is formed Island becomes 50 MW generation rich and sharply frequency rises from 48.4 HZ TO 50.2 Hz and settles to 50 Hz.

Scenario-2 : Maximum generation & Minimum load



Discussion:

1. In max generation min load scenario, there is 160 MW surplus generation inside the Island.
2. As the one big generator tripped to replicate frequency fall, Unit of NPGC will also respond to this frequency change and which is limited to 105% of the generation so generation increased till 690MW from 660 MW.
3. As the frequency touches 48.4 Hz and island is formed Island becomes 190 Mw generation rich and sharply frequency rises from 48.4 HZ TO 52.4 Hz and settles to 50.5 Hz.
4. As per information received at 52 Hz -2 sec O/F alarm is only there no direct frequency based relay but , turbine speed related tripping is there .
5. **In respect to above Generator over frequency/Turbine speed related tripping may be kept upto 53 Hz if possible, to ensure sufficient margin and avoid unit tripping on over frequency.**

Scenario-3: Minimum generation & Minimum load

Discussion:

1. In min generation min load scenario, there is 120 MW generation deficit inside the Island and without any measure island will collapse. Measure are mentioned below ,

- In scenario where Generation is minimum, Loads are becoming High in the island in both the cases of Minimum & Maximum load, so to tackle this situation and avoid fast frequency dip as well as to limit the rate of frequency down following should be done at the instant of island formation,
- Whenever Load >80 MW of Generation, Trip 50 MW at the instant of island formation at (48.4 Hz).
- Whenever Load >150 MW of Generation, Trip 150 MW at the instant of island formation at (48.4 Hz).

Even after that island will be load rich in case of minimum generation so Under frequency inside the island is proposed to trigger at 48.2 Hz.

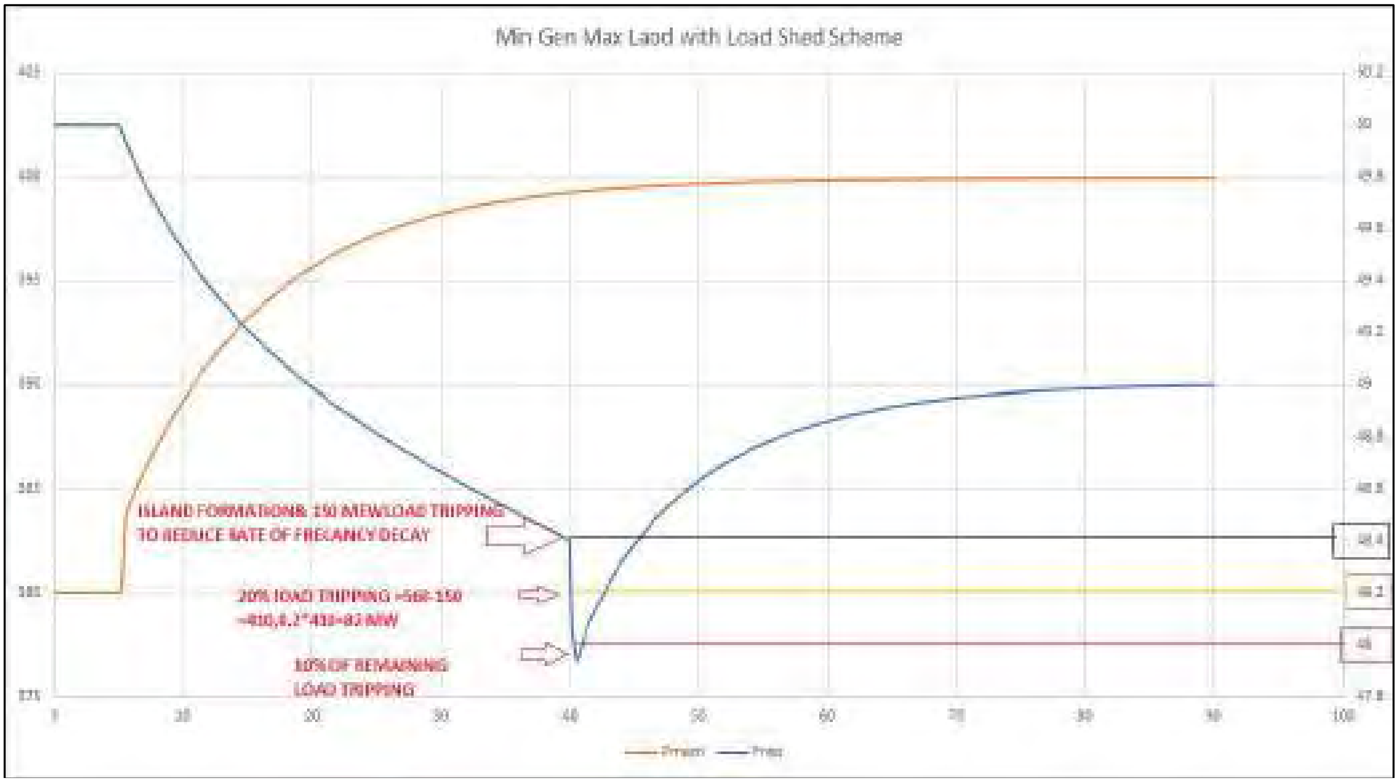
The details are as follows

- 48.2 HZ 100 ms 20 % of island load
- 48.0 Hz 100 ms 10% of Island load
- 47.8 Hz 100 ms 10 % of Island load.

2. As the one big generator tripped to replicate frequency fall, Unit of NPGC will also respond to this frequency change and which is limited to 105% of the generation so generation increased till 400MW from 380 MW.
3. As the frequency touches 48.4 Hz and island is formed with 50 MW LOAD TRIPPING, Island becomes only 50 MW generation deficit and frequency further decreases from 48.4 HZ TO 48.2 Hz.
4. At 48.2 Hz and UFLS stage-1 inside the island will trip 20% of load excluding NPGC load which is essential for survival so out of 450, (500-50(already tripped) ,(450-80=370) MW and its 0.2*370=74 MW will trip now island load will be ,(370-74)=296+80=376 MW.
5. Now load Generation are balanced so frequency settled to 50 Hz.
6. As per information received at 47.4 Hz -2 sec under frequency tripping is enabled.

7. **In respect to above it appears no under frequency tripping OF UNIT should occur.**

Scenario-4: Minimum generation & Maximum load



With the proposed UFLS scheme ISLAND is becoming stable.

Summary:

SCENARIO	Generation	Load	Surplus/Deficit	Remarks
Scenario-1 (Max GEN& MAX LOAD)	660 MW	640 MW	20 MW	**In this scenario, island can survive.**
Scenario-2 (Max GEN& MIN LOAD)	660 MW	500 MW	160 MW	**In this scenario, island can survive. Generator over frequency/Turbine speed related tripping may be kept up to 53 Hz if possible, to ensure sufficient margin and avoid unit tripping on over frequency.**
Scenario-3 (MIN GEN& MIN LOAD)	380 MW	500 MW	-120 MW	**In this scenario, island can survive only if the proposed UFLS along with load tripping of 50 MW at the instant of islanding is implemented.**
Scenario-4 (MIN GEN& MAX LOAD)	380 MW	640 MW	-260 MW	**In this scenario also, island can survive only if the proposed UFLS along with load tripping of 150 MW at the instant of islanding is implemented.**

Based on the above study following islanding logic is proposed:

- Islanding should happen before pick up of any of the frequency protection stage and that's why island formation will start at 48.4 Hz with a delay of 500 m sec.
- In scenario where Generation is minimum, Loads are becoming High in the island in both the cases of Minimum & Maximum load, so to tackle this situation and avoid fast frequency dip as well as to limit the rate of frequency down following should be done at the instant of island formation,
  - Whenever Load >80 MW of Generation, Trip 50 MW at the instant of island formation at (48.4 Hz).
  - Whenever Load >150 MW of Generation, Trip 150 MW at the instant of island formation at (48.4 Hz).

Even after that island will be load rich in case of minimum generation so Under frequency inside the island is proposed to trigger at 48.2 Hz.

The details are as follows

- 48.2 HZ 100 ms 20 % of island load
- 48.0 Hz 100 ms 10% of Island load

  47.8 Hz 100 ms 10 % of Island load.
- Generator over frequency/Turbine speed related tripping may be **kept at 53 Hz** if possible, to ensure sufficient margin and avoid unit tripping on over frequency.

Limitation of the study:

1. In absence of any guideline for islanding study, we have applied a frequency disturbance in the grid and grid is simulated with closely matching inertia and Governor Response. However, it is well known that during such large disturbance lot of other protective control features of various generators, other equipment may come into picture. Also, UFLS of grid side impacts the frequency dynamics and the ROCOF. Those phenomena are difficult to consider in the study. Therefore, not considered here.
2. The exact governing behavior of the units has high impact on the island study, however those detailed model of a plant considering influences from speed and pressure control loop is not modeled here. Plants may consult OEM for the detailed study considering those control action.
3. Initial ROCOF has also has huge impact of island stability after separation, however this ROCOF depends on lot of things and very difficult to predict. Also, there is no guideline in Indian context what ROCOF should be considered during such study.
4. Therefor the above study is only showing a tentative frequency excursion of the island and helping in arriving a suitable starting logic for island formation and stability within the island.

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Projekt ID	Second 1x500 MW HVDC Back to Back Project at Vizag

Memorandum

To: Anders Bergdahl

Copy:

Subject: Vizag Trips in connection with Ferro Resonance

1 Observations during trips

From the TFR data supplied in connection to the recent trips related to ferroresonance it is concluded that the system behaves as expected in case of ferroresonance. The frequency observed during the ferroresonace is approximately 41 Hz, measured in the d.c. quantities.

In the studies performed by ABB at the project stage the typical ferroresonance frequency was 42 Hz observed on the d.c. side [1].

2 Prior ABB recommendations to customer

In the ferroresonance report issued by ABB, [1], the main recommendation was that

> "At detection of ferroresonance bypass the series compensation. The best solution is to detect the ferroresonance at the series compensation itself."

A brief summary of the conclusions in the report is given in [2].

In the report a ferroresonance detection function in the ABB control is described. The output from this function is a digital signal that could be used as an indication of ferroresonance. The signal is made avilable for external use at the customer inerface digital output terminals. From here the customer could pick up the indication signal and send it to the control system of the series compensation where it could be used as a backup to local detection. It could also be used at the series compensation to trig a bypass.

A general observation in the report was that it is beneficial from a stability point of view to draw as much active power as possible to damp the ferroresonance oscillations. In connection to this it may be pointed out that the power level for insertion of the series compensation should be as high as possible.

As a reminder also please note the recommendation

> "In reverse power operation the series compensation should be bypassed."

3 Trip from transformer differential protection

The transformer differential protection is designed to be stable during different disturbances in the 50 Hz network, such as a.c. faults, over-excitation and inrush current. This is achieved by a harmonic restraint function, which blocks the

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Sweden				

operation at a certain degree of 100 Hz or 250 Hz current. However, at ferroresonance the a.c. voltage is heavily distorted, which generates a variety of frequencies in the transformer magnetization current. The restraint function can not provide stability during these extreme conditions, and the protection trips the transformer.

In order to improve the stability during ferroresonance, ABB proposes to modify the protection as described below:

- The delay time for the harmonic restraint trip is increased from 10 ms to 20 ms in order to accomplish a full-cycle integration of the 50 Hz component in the restraint function.
- The operation level is increased for a limited time period at detection of ferroresonance in order to give time for disconnection of the series capacitor. This extra stabilisation will be carried out considering that the protective performance at a transformer fault must be preserved.

It must be noted that the a.c. voltage distortion during ferroresonance is much higher than specified continuous distortion level. The resonance should be stopped as soon as possible, otherwise the HVDC transmission might trip on harmonic overload in a.c. filters, or harmonic current in the d.c. current. Therefore, the key action is to disconnect the series capacitor on detection of ferroresonance.

4 References

1. ABB Technical Report 1JNL100098-933, “Mitigation of Ferroresonance”
2. ABB Letter 04OPV0171

Second 1x500 MW HVDC Back to Back Project at Vizag	Document Number 1JNL100098-933	No of Pages 16 No of Attached Page
Prepared Thomas Tulkiewicz, 2004-04-06	Title Mitigation of Ferroresonance	Reg./Class no. LVZ-FG-74
Approved Erik Jansson, 2004-04-22 / Resp Dept /TST		

Summary

The conclusion of the ferroresonance investigation presented in this report is that for operation of the Vizag_II link and the combined Vizag_I and Vizag_II links within the defined operating limits ferroresonance will occur for different types of disturbances but it is shown that the oscillations are well damped, thus the influence on the performance is limited. This is valid for power transmission from east to South, i.e. in forward power direction. In reverse power direction the risk for sustained oscillations is high and the recommendation is to operate with bypassed series compensation only.

When ferroresonance occurs the most effective means of mitigation is fast detection of the typical ferroresonance frequency combined with bypass of the series compensation.

Since transformer energization is a sensitive operation it is recommended to energize transformer with the series compensation bypassed and connect series compensation at higher power level

Rev ind	Revision text	Prepared	Approved

Table of Contents

1 Introduction

Ferroresonance refers to an oscillation phenomenon, that can appear in a network in the presence of:

- a non-linear inductance
- a capacitor
- a voltage source
- low losses

A typical case is a non-linear inductance, e.g. a saturable transformer, fed by a series capacitor.

In the case of ferroresonance more than one stable steady state is possible for a given configuration. Characteristic for ferroresonance is that sudden transits in voltage or current between these stable states can occur. Resonance is possible in a vide range of combinations of the capacitor and the non-linear inductance. A number of factors such as voltage magnitude, initial magnetic flux in the transformer inductance, total losses in the power circuit and point-of-wave of disturbances will effect the ferroresonance behaviour.

The result is badly distorted voltages and currents containing sub-harmonic components, which can be sustained depending the preconditions.

From the HVDC point of view ferroresonance should be eliminated to avoid unneccessary protective actions due to high levels of harmonic distortion.

2 General modelling

In this investigation the modelling of the combined Vizag_I and Vizag_II HVDC transmissions in EMTDC has followed the outline given in the DPS Study Outline [2]. The EMTDC modelling of Vizag_I considering both the main circuits and the control follows the assumptions made in [3]. Some of the input data assumed would however have needed to be confirmed in order to have full confidence in the Vizag_I model.

Based on these preconditions the performance of Vizag_II in operation together with Vizag_I can only be optimized to a certain point since the Vizag_I influence is dependent on the assumptions made.

During commissioning the possible occurrence of ferroresonance will be carefully monitored. This will be especially important when both Vizag_I and Vizag_II are in operation since this mode of operation will show the proper interaction between the two transmissions and also interaction with the series compensation. It cannot be excluded that some final tuning of Vizag_II controls may be needed.

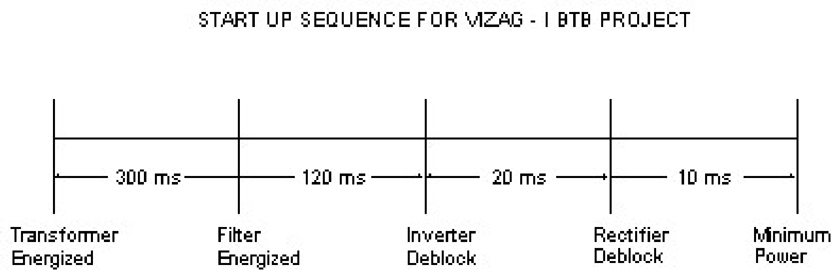
2.1 Series Compensation Model

The series compensation has been modelled with the series capacitors in parallel with a circuit consisting of a damping resistor, an inductance and a breaker. The values of the damping resistor and inductance are according to data provided by PGCIL [1].

During steady state operation the voltage across the series capacitor is up to approximately 60 kV peak value. The voltage level depends on what power is transmitted and if one or two lines with SC is connected. During faults and recovery after faults the ferroresonance results in distorted AC voltages and high peak voltages. In many of the cases studied it has been assumed that some kind of protection, usually a combination of voltage and sub-harmonic current protection, will be activated and order a bypass of the series capacitor. This has been simulated in the study by ordering a bypass at 50 ms after the application of the fault. Bypassing the series capacitor gives stable recovery, free of ferroresonance oscillations. In a real situation the series capacitors will be reconnected when the conditions for ferroresonance have disappeared. The reconnection of the series capacitors is usually very smooth since the capacitors have been discharged. In these simulations the series capacitor is reconnected about a second after the fault has been released, without any problems.

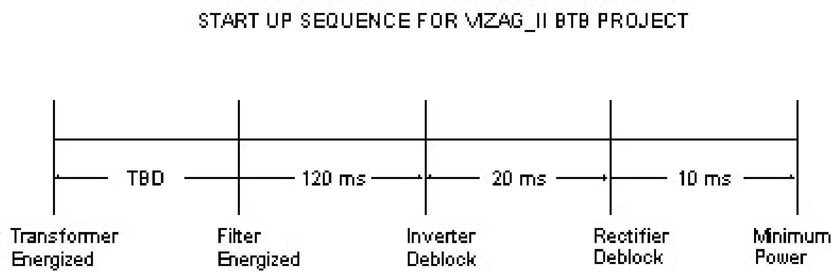
2.2 Starting Sequences

The starting sequence for Vizag_I has been simulated according to information provided by PGCIL, see fig 1



According to PGCIL the timings above are typical values and may vary.

For Vizag_II a similar start up sequence has been used during the simulations.



For Vizag_II the procedure from filter energization to operation at minimum power is part of the start up sequence and thus set in the controls. The time from transformer energization to filter energization, i.e. the possibility to operate in a stand by mode with only transformer energized has to be investigated during commissioning.

3 Detection of ferroresonance and mitigation actions

The most effective action from a stability point of view if an oscillation due to ferroresonance occurs, is to temporarily bypass the series compensation as quickly as possible. The fastest way to achieve this is to have a function installed in the control system of the series compensation itself, which detects the ferroresonance and issues a bypass order.

As an alternative or as a redundant means of detection, this can be done by the ferroresonance detection function in the ABB controls that will make an indication signal available for external use.

The detection function measures the East bus AC voltage. The detection incorporates a filter function set to only detect the frequencies involved at ferroresonance. The filtered signal is compared with a reference level which includes harmonic distortion at normal operation. The output from the function is a digital signal which can be used as an indication of ferroresonance.

This indication signal can be sent to the control system of the series compensation and there trig a bypass order. The series compensation can be reconnected as discussed in section 2.1. To use an ABB control system signal will require a communication link between the converter station and the series compensation. If available, PLC communication would be sufficient.

A general observation in the cases studied is that it is beneficial from a stability point of view to draw as much active power as possible to damp the ferroresonance oscillations. If an oscillation occurs as a result of e.g. a shunt element switching or a phase to ground fault, during power ramping or at steady state, the study results indicate that the oscillation will be mitigated by continuing ramping or by a temporary increase in active power, depending on network conditions and present power level. This will have to be investigated during commissioning.

4 Results

4.1 Energization and Start Up to Minimum Power

The studies show that it is no problem to deblock Vizag_II and stay at minimum power. There is a 50 Hz ripple in the DC quantities which comes from saturation of the transformer but this is damped. The behaviour is dependent on that the start sequence is correct but this is defined in the controls and is thus applied automatically.

Minimum power faults have been applied both in the rectifier and the inverter. The results show a stable recovery. An oscillation at the typical ferroresonance frequency 42 Hz appears on the DC side at fault release but is damped. This is the same behaviour as for cases with higher power transfer.

The connection of the second filter during ramp up to full power is made without any problems. At 1 pu power the shunt reactor is disconnected, also in a stable manner. The ramp up is shown as case 1.

During operation at min power and during ramp up of power the conditions for reactive power balance have been simulated by manually setting the proper preconditions. In the plant this will be controlled by the RPC.

With Vizag_II running steady state at minimum power Vizag_I was started to minimum power applying the given start sequence for Vizag_I. This start up leads to some general distortion with oscillations at 50 Hz which are damped within some seconds. However no ferroresonance occurs.

As stated earlier, in order to damp ferroresonance it seems to be beneficial to export as much active power as possible form the network. It is preferable to increase the active power in Vizag_II before Vizag_I is started. This is shown in the case 2 where Vizag_II is running at 500 MW when Vizag_I is started. As soon as Vizag_I starts to transmit active power (at t=2s) the oscillation is more damped.

This example also demonstrates how the capability of Standby operation should be best used. If Vizag_II runs at full power Vizag_I should be either in a non-energized mode or be energized and running with minimum power.

Generally one cause of ferroresonance is energization of transformers which are fed from series compensated lines. A solution, should ferroresonance occur, is to have the series capacitor(s) bypassed during energization and startup of the HVDC system. The series capacitor(s) are connected at a higher power level when the risk for ferroresonance is less and the series compensation is needed.

4.2 Forward Power Operation

Since power transmission from East to South will be the predominant direction of power several scenarios have been investigated in Forward Power Operation.

Two lines with Series Compensation between Gazuwaka and Jeypore
Vizag_II: 550 MW, Vizag_I: 550 MW

One line with Series Compensation between Gazuwaka and Jeypore
Vizag_II: 500 MW, Vizag_I: 250 MW

One line with Series Compensation between Gazuwaka and Jeypore
Vizag_II: 500 MW, Vizag_I: startup

One line with Series Compensation between Gazuwaka and Jeypore
Vizag_II: startup, Vizag_I: startup

In these scenarios the performance of the link and the occurrence of possible ferroresonance has been studied for a number of typical switching actions such as filter and shunt reactor switching and bypass and reconnection of the series capacitors. Also 1- and 3-phase to ground faults on the converter bus have been studied with and without bypassing the series compensation.

The cases with switching of filters, shunt reactors or bypass/reconnection of series compensation show a stable performance without any indication of ferroresonance. When the series compensation is reconnected a small ferroresonance oscillation is observed but it is quickly damped within 0.3 ms.

The ground faults show a typical behaviour. When the fault is released a ferroresonance occurs but the amplitude of the oscillation is small and is damped within 0.5 – 0.6 s. The ground fault cases have been repeated with bypassing of the series compensation. These cases show a normal, stable recovery. In these cases the series compensation is reconnected at 1 s after the release of the fault.

A typical 3-phase to ground fault behaviour is shown in case 3. Case 4 shows the same fault case but with bypassing the series compensation during the fault. The series compensation is reconnected at t=1.3s. At reconnection a ferroresonance occurs but is quickly damped within less than 250 ms.

4.3 Reverse Power Operation

In reverse power the following scenarios have been studied:

Two lines with/without Series Compensation between Gazuwaka and Jeypore
Vizag_II: 500 MW, Vizag_I: 250 MW

One line without Series Compensation between Gazuwaka and Jeypore
Vizag_II: 500 MW, Vizag_I: not connected

In reverse power operation the power is fed into the system containing the series compensated lines. This results in deterioration of the behaviour if the ferroresonance is excited as compared to forward power operation where the power is exported from the system. The risk for sustained ferroresonance is very high.

A typical result of a rectifier (South side) fault is shown as case 5.

Reverse power is assumed to be a rare mode of operation. In view of this and in order to avoid ferroresonance problems ABB's recommendation is to have the series compensation bypassed in reverse power operation.

4.4 Effect on South Network from Oscillations in East Network

The effect on the south network when a fault is applied on the East AC bus was compared for the two cases with and without series compensation, case 6. The results of a Fourier analysis of the South AC bus indicate that the harmonics just after release of the fault come from the application of the fault itself. There is a slight increase at 90 and 110 Hz in the case with SC. This is the result of mirroring of the 8 Hz, 50-42 Hz, round the 2nd harmonic. Due to the resolution of the Fourier analysis the 8 Hz is seen as 10 Hz.

4.5 Influence on Subsynchronous Torsional Interaction

Subsynchronous torsional interaction (SSTI) involves the influence of HVDC controls on the interaction between generators and the AC network when the HVDC operates in rectifier mode.

For Vizag_II the generators of concern would be the Simhadri generators. These will normally be operating on the inverter side of the HVDC transmission, thus there is no direct connection to the series compensation. In the rare case of reverse power operation ABB's recommendation is to operate with the series compensation bypassed.

There is a possibility of transfer of oscillations to the South network if a fault occurs on the East side. This has been investigated and as described in section 4.4 the influence on the south bus AC voltage is very small. This will not be a concern. However a fault case will be included in the SSTI study to further investigate this from an SSTI point of view.

Use of Vizag_II Bypass interconnection should be done only with series compensation bypassed due to possible subsynchrounous interaction with the Simhadri generators.

5 Conclusions and Recommendations

The conclusion of the ferroresonance investigation presented in this report is that for operation of the Vizag_II link and the combined Vizag_I and Vizag_II links within the defined operating limits ferroresonance will occur for different types of disturbances but it is shown that the oscillations are well damped, thus the influence on the performance is limited. This is valid for power transmission from East to South, i.e. in forward power direction.

The following possible remedies to limit ferroresonance have been identified:

- At detection of ferroresonance bypass the series compensation. The best solution is to detect the ferroresonance at the series compensation itself.
- If ferroresonance occurs increase power if possible.
- Transformer energization is a sensitive operation.
    - Start up and deblock using the defined sequences and increase power above min power as soon as possible.
    - Ramp up power in one link before energizing the next.
    - Energize transformer with series compensation bypassed and connect series compensation at higher power level
- In reverse power operation the series compensation should be bypassed.

Final investigations at site during commissioning has to be done to cover differences between network model and actual network.

Ferroresonance detection may be required in Vizag_I. Due to the limited knowledge of Vizag_I data further optimization e.g. the Vizag_I control system should also be considered.

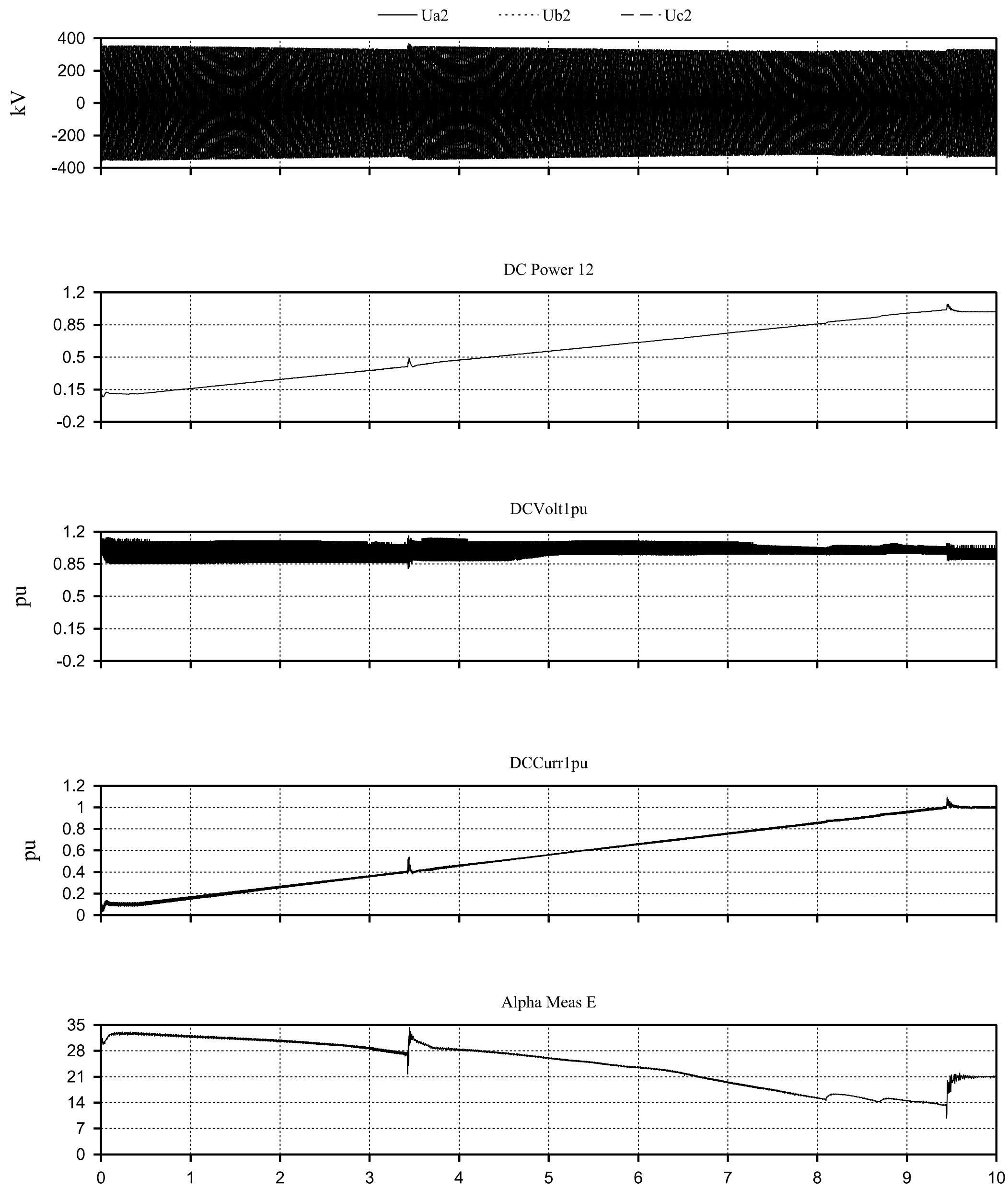
6 References

1. C/ENGG/HVDC/VIZ_II/S/ Letter dated 24.11.2003
2. 1JNL100060-737, Rev 02, “Study Outline for DPS”
3. 03TST0372, Rev 01, “Vizag_I , assumptions for Vizag_II studies”

Case 1

Case description: Ramp up of power from minimum power to 1 pu power. At 0.4 pu power (t≈3.5) the second filter is connected. At 1 pu power (t≈9.5) the shunt reactor is disconnected.
One line with series compensation.

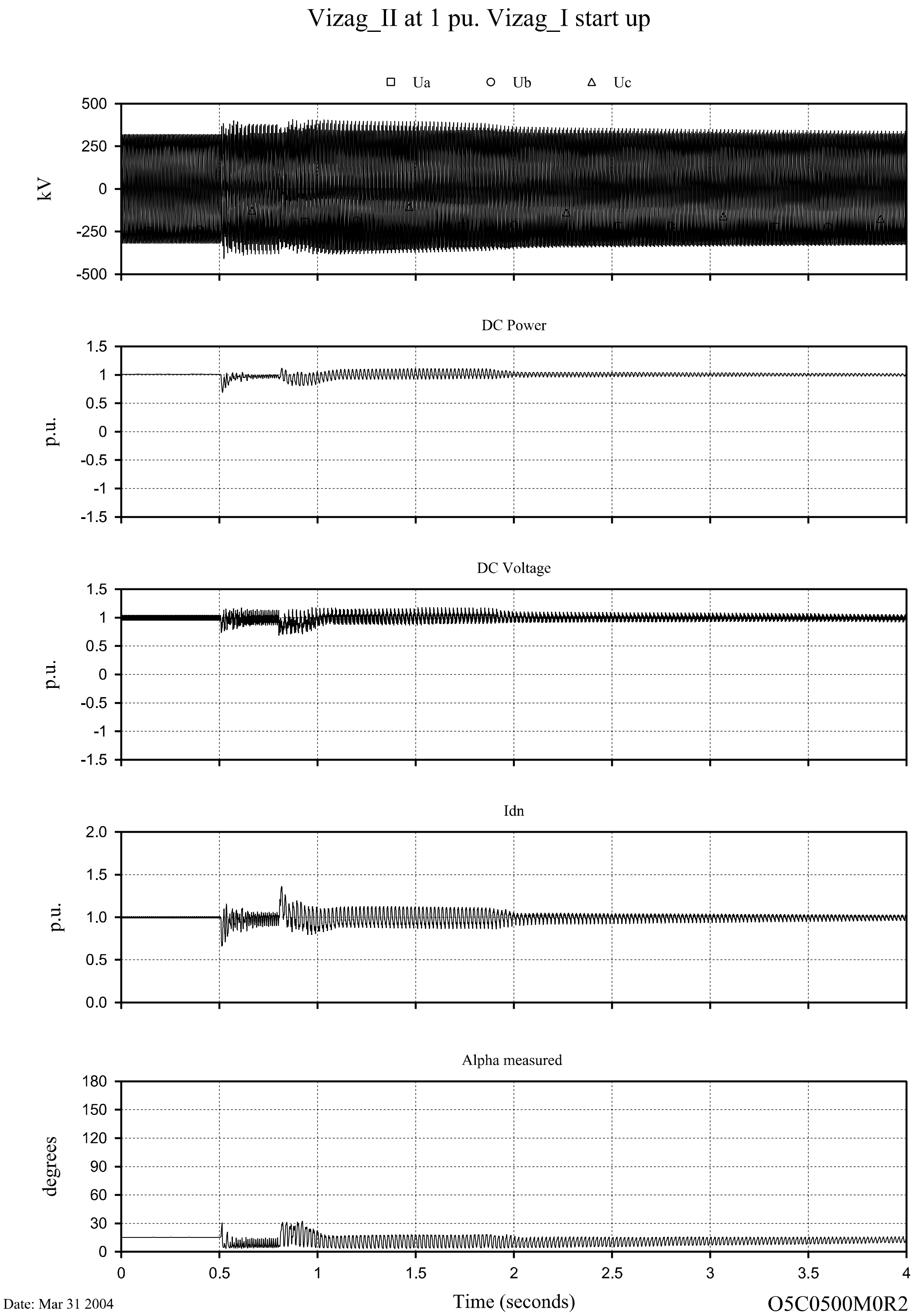
V2_East



Case 2

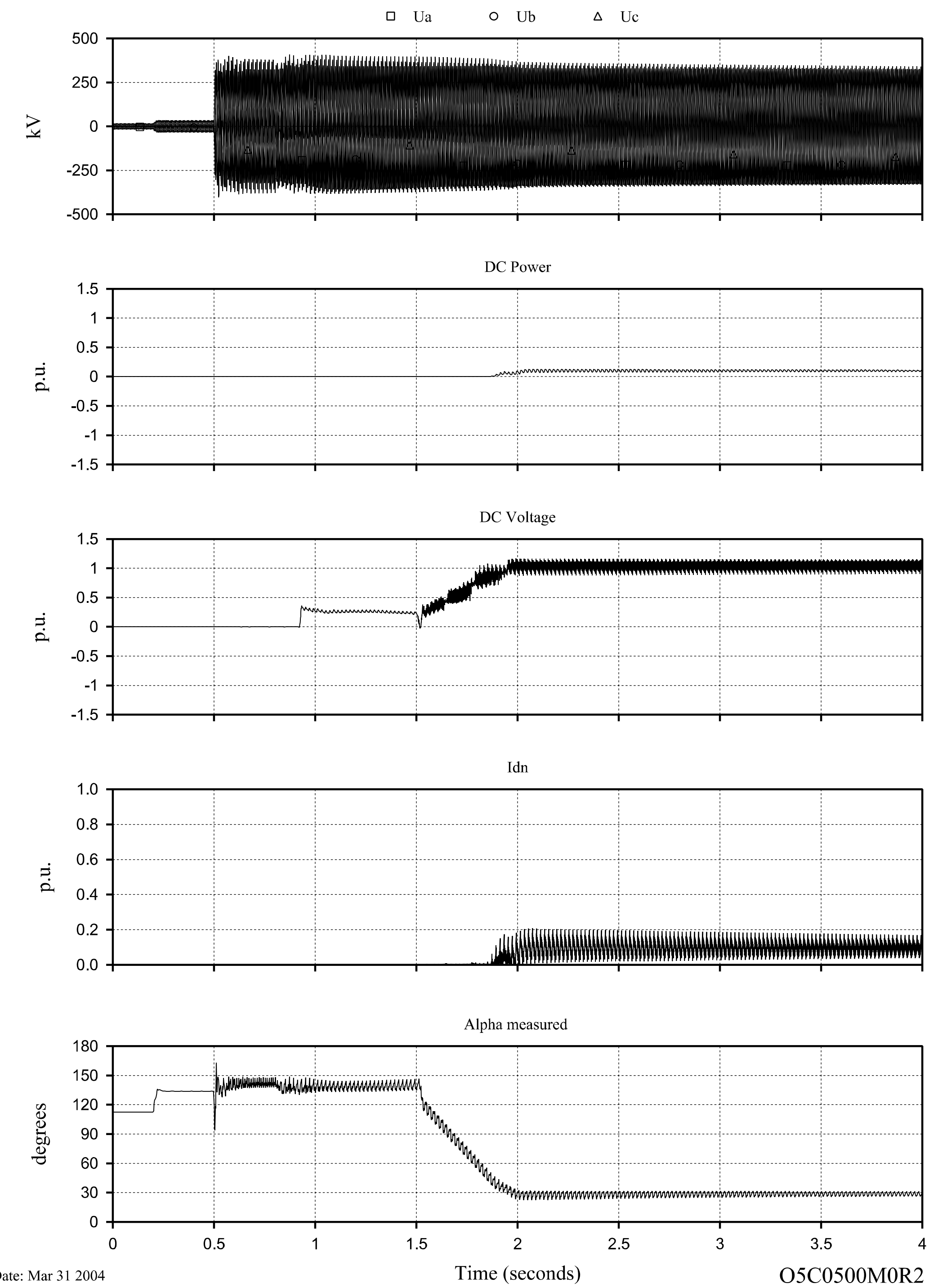
Case description: Vizag_II running at 1 pu power. Energization of Vizag_I transformer and start up according to given procedure.
Graphs for Vizag_I East on next page

East Station V II



East Station V I

Vizag_II at 1 pu. Vizag_I start up



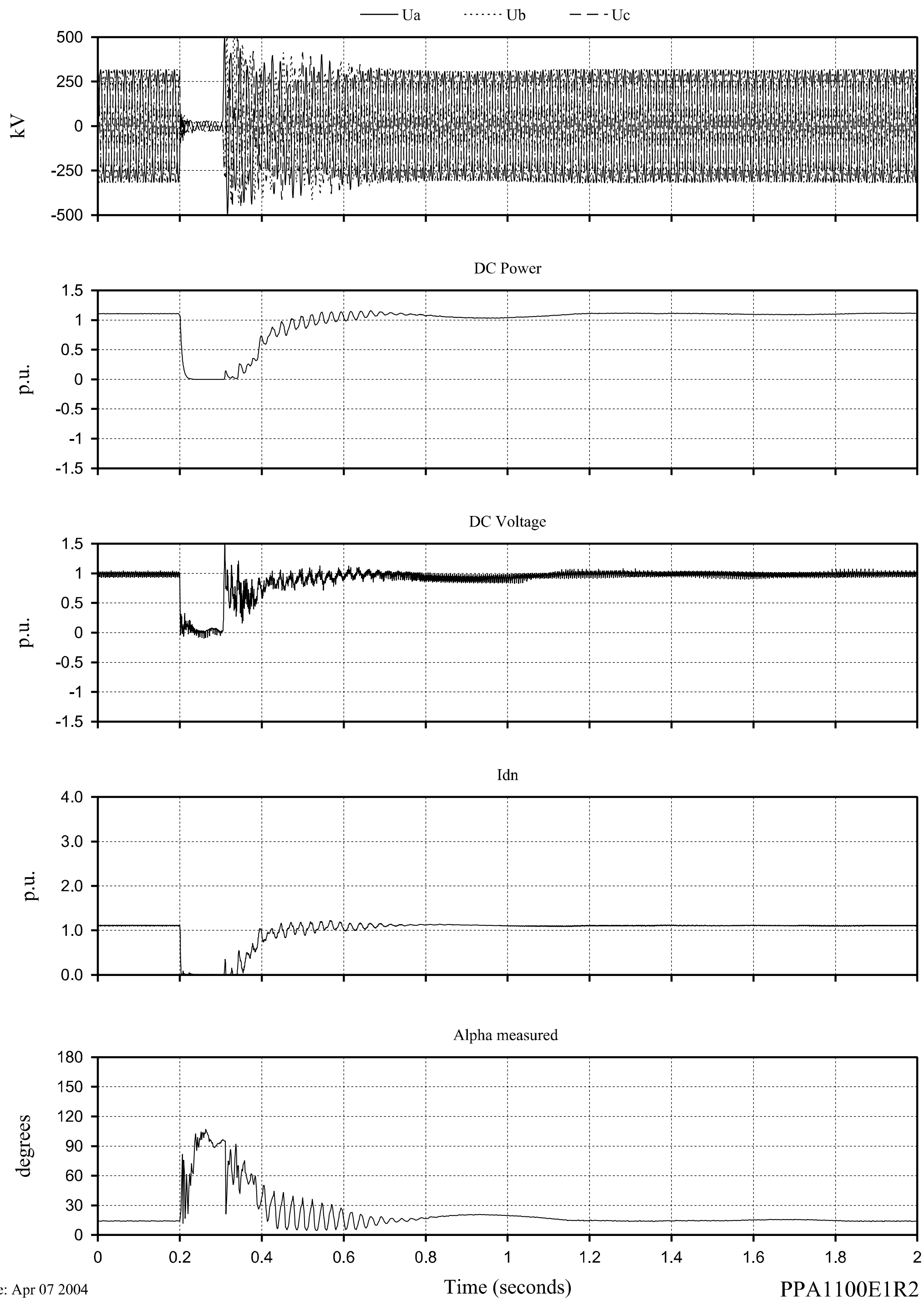
Date: Mar 31 2004 O5C0500M0R2

Case 3

Case description: Peak load networks East and South. 3-phase to ground fault on East AC bus, 100 ms, < 10% remaining voltage
Two lines with series compensation

East Station V II Peak, 1100 MW E->S

Rectifier, 3ph fault, 5 cycles, <10 percent



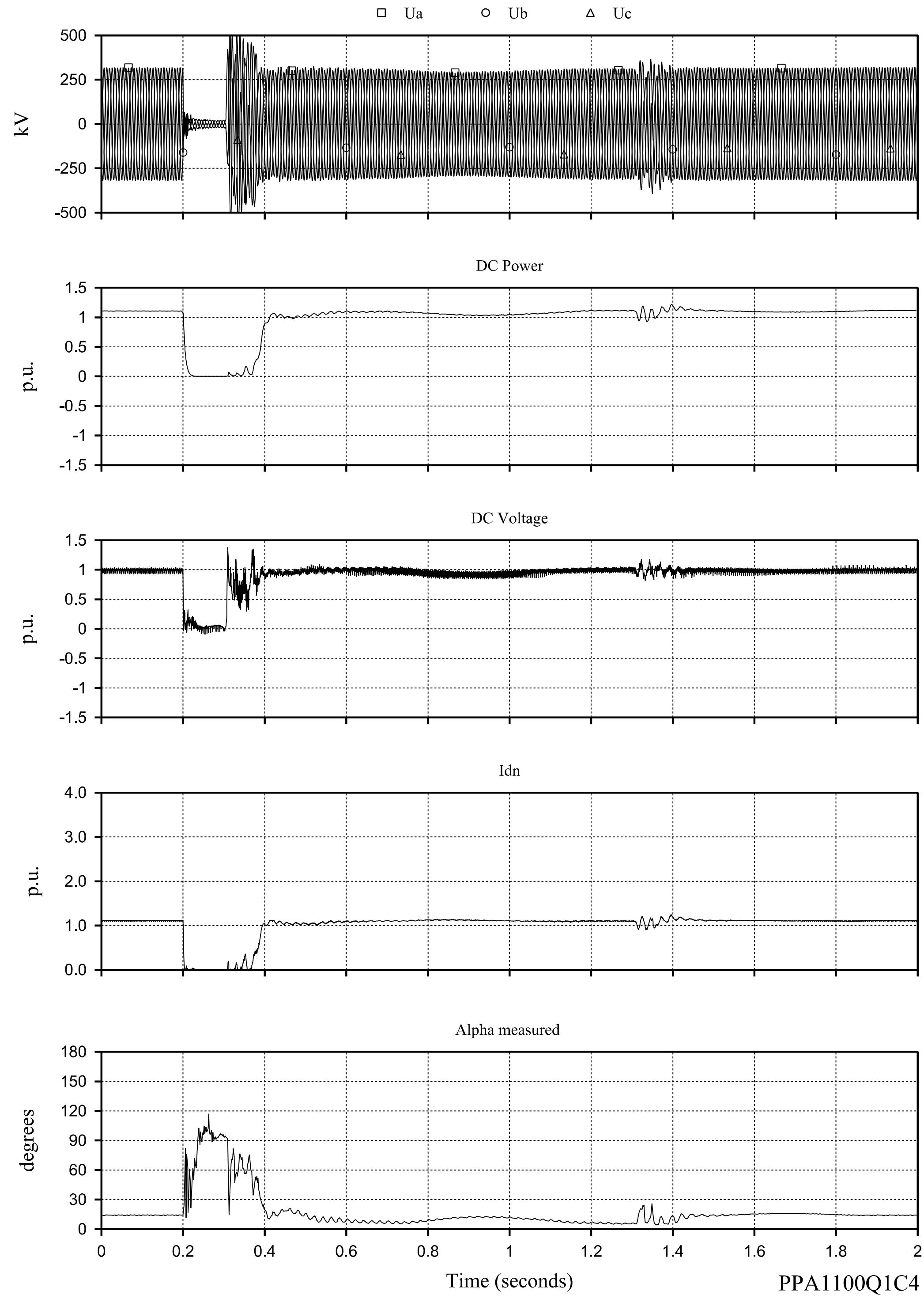
Date: Apr 07 2004 PPA1100E1R2

Case 4

Case description: Peak load networks East and South. 3-phase to ground fault on East AC bus, 100 ms, < 10% remaining voltage
Two lines with series compensation
The series compensation is bypassed 50 ms into the fault and reconnected at 1.3 s.

East Station V II Peak, 1100 MW E->S

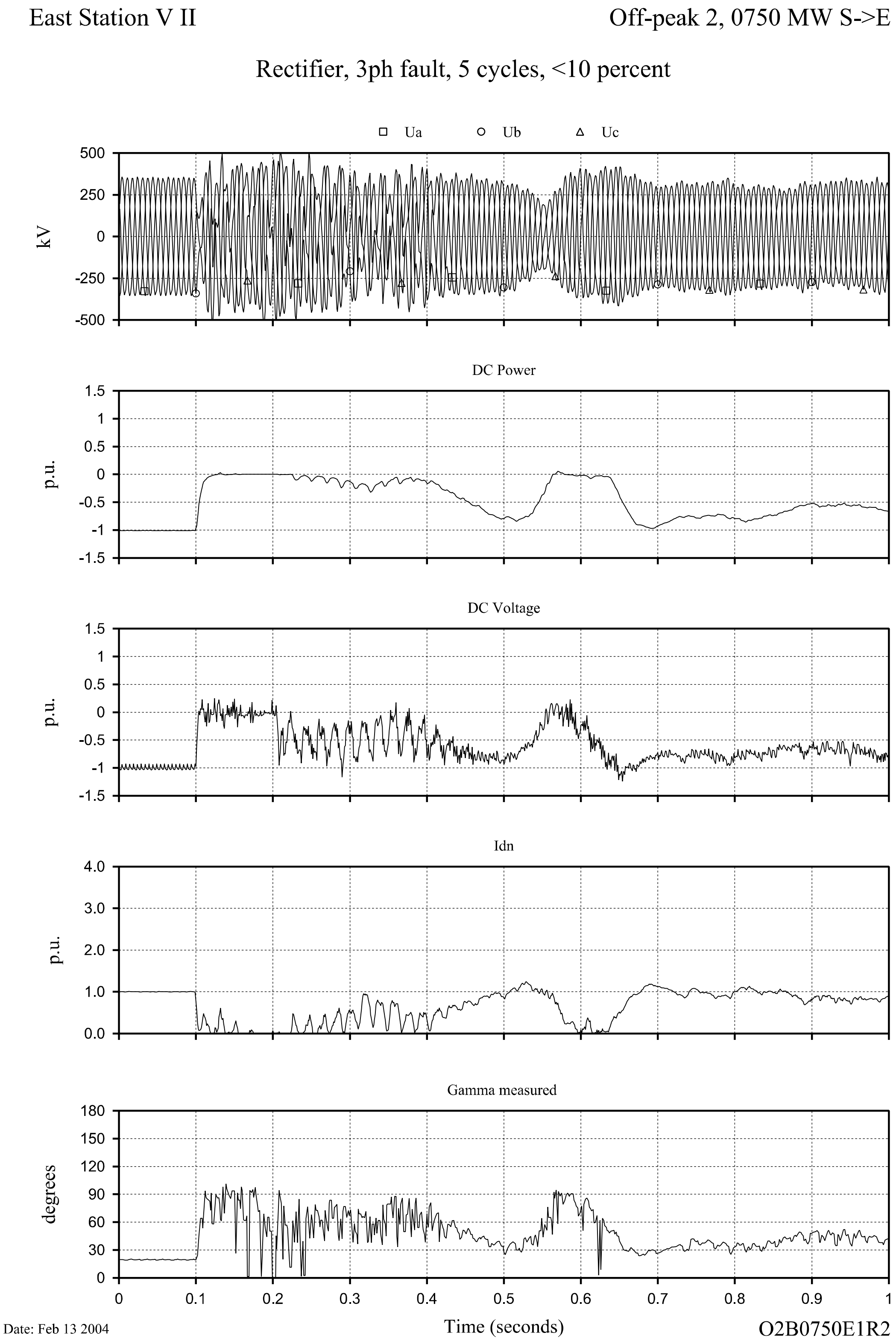
Gazuwaka - Jeypore, 3ph fault, 5 cycles, <10 percent



Case 5

Case description: Reverse Power, Peak load networks East and South. 3-phase to ground fault on South AC bus, 100 ms, < 10% remaining voltage Two lines with series compensation

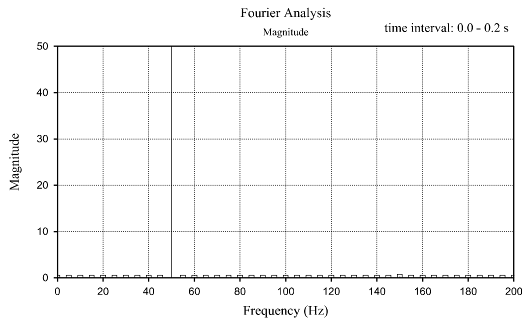
The plot shows Vizag_II inverter side quantities (East side)

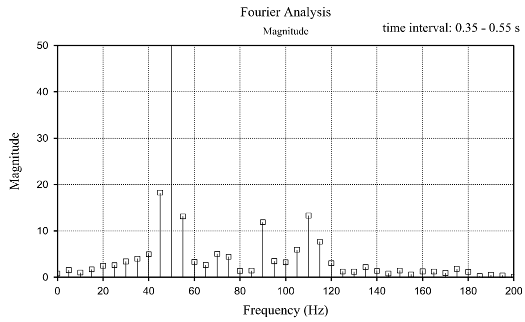


Case 6

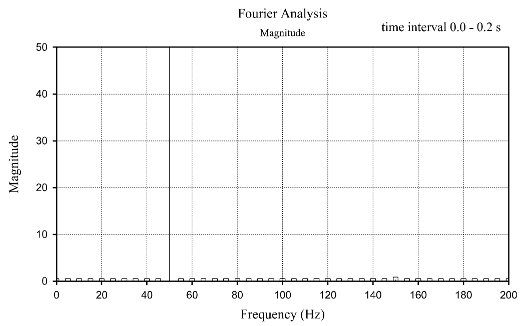
Case description: Fourier analyse of South AC bus. 3-phase to ground fault on East AC bus, 100 ms, < 10% remaining voltage
Comparison for cases with series compensation (upper two) and with series compensation bypassed after fault.
The two diagrams in each case show prefault and postfault Fourier result

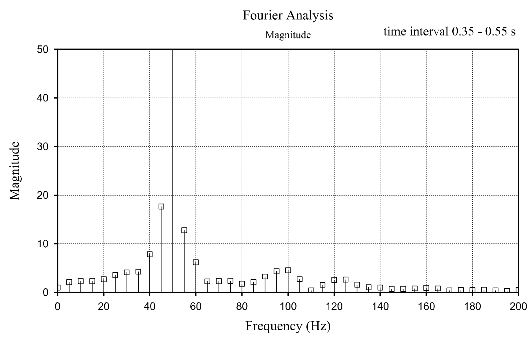
With SC





No SC





List of AR of Jeypore-Gajuwaka-1 & 2 line during high Power flow (No Ferro resonance detected)

S.No	Line	TripTime	RestTime	Reason	Power flow	Direction
1	JEY-GWK II	12/05/19 14:37	12/05/19 14:37	Autoreclose successfull at both ends on B-N fault at 14:37Hrs/12.05.2019. Fault Details: Gajuwaka End: M1:114.8kM,FC- 2.11kA; M2:106.7kM; Jaypore end: Dist 86.73KM(M1),93.0KM(M2) Fc:3.32KA	650	E->S
2	JEY-GWK I	11/05/19 17:57	11/05/19 17:57	Autoreclosde successfully at both ends on Y-N fault (Fault Details: Gajuwaka End: M1:217kM, 1.5kA; M2:199.3kM, 1.5kA; Jeypore End: FD:21.55kM.(Jeypore Jurisdiction)	650	E->S
	JEY-GWK I	23/04/19 16:23	23/04/19 16:23	Auto Reclosure successful on both ends on R-N fault	500	E->S
3	JEY-GWK I	13/04/19 13:10	13/04/19 13:10	Autoreclosed sucessfull on B-N fault GWK End: Main-1: 165.2KM, 1.06kA & Main-2: 148.3KM, 1.3kA. Jeypore End: Main-1: 46.42KM, 4.11kA & Main-2: 44.2KM, 3.22kA	650	E->S
4	JEY-GWK I	20/03/19 15:04	20/03/19 15:04	Auto reclose successful on R-N fault at 15:04Hrs/20.03.2019. GWK: FL-189.6KM,FC-0.76KA,Jeypore: FL-87.4KM,FC-4.21KA	600	E->S
5	JEY-GWK I	02/06/18 15:11	02/06/18 15:11	AR Successful at both ends on R-N fault. From GWK M1: Fault dist:87.6Kms, FC:1.36kA & M2: Fault dist:91.17Kms, FC:1.093kA. From Jeypore M1 distance 104.3 kms, FC:2.161kA & M2 distance 99 kms, FC:1.96kA. FSC bypassed at Jeypore end.	550	E->S
6	JEY-GWK I	07/04/18 20:00	07/04/18 20:00	AR successful on Y-N fault at both ends.From GWK end: FC-2.84 KA,Distance-5.30KM;From Jeypore end: FC: ,Distance-221KM	600	E->S
7	JEY-GWK I	20/06/17 14:00	20/06/17 14:00	A/R sucessful both ends on R-N fault. 70KM, 2.1KA from Gajuwaka end and 110KM, 1.75KA from Jeypore end.	550	E->S
8	JEY-GWK I	08/05/17 14:42	08/05/17 14:42	Auto reclose successful at both ends on B-N fault. Dist 166.20kms, FC-0.73kA from GWK end. Dist:14.33kms, FC:3.53kA from Jeypore end.	600	E->S
9	JEY-GWK I	08/05/17 13:35	08/05/17 13:35	Auto reclose successful at both ends on B-N fault. Dist 154kms, FC-0.5kA from GWK end. Dist:43.8 kms, FC:3.22kA from Jeypore end.	600	E->S
10	JEY-GWK II	07/06/16 16:16	07/06/16 16:16	Autoreclosed successfully on B-N fault. FL: 64.5kms, 1.25kA from GWK end	600	E->S

Annexure-C10

2½ (?)

North Bihar Power Distribution Company Limited

(Regd. Office : Vidyut Bhawan, Bailey Road, Patna)
CIN:- U40109BR2012SGC018920
(Commercial Department)

M.No: 9264437178
E-mail:- cecom2.nbpdcl@gmail.com
nbpdcl.pp.2021@gmail.com

Letter No.............................. Date:-..............................
NB/Comm/P.P/24/2022

From,

Deepak Kumar
Chief Engineer (Commercial)

To,

Sri Amaresh Mallick
CGM & HOD (System & Operation)
Eastern Regional Load Dispatch Centre,
14, Golf Club Road, Tollygunge,
Kolkata-7000033.
E-mail:- erldcinfo@posoco.in

Sub.: Revision of Schedule by ERLDC from retrospective effect.

Sir,

With reference to above, it is found that actual schedule provided is modified with retrospective effect sometime. Recently such retrospective change in schedule has been observed in schedule from Ostro Kutch Wind Private Limited for 01/04/2022 and 25/04/2022. The revision no. just after the midnight is 204 and 202 for 01/04/2022 and 25/04/2022 as per the ERLDC website. However, this scheduled has been changed vide revision no. 207 and 208 for 01/04/2022 and 25/04/2022 respectively. Due to these type of revision, there is difference of 31,575 KwH between ERLDC website and REA.

It can be noted that such revisions with retrospective effect will have financial implications in view of following:-

- The power drawl is monitored and controlled, if required to match the Schedule provided for each time block on continuous basis. However, any change in schedule with retrospective effect makes such monitoring and control of drawl with an aim to match the schedule a futile exercise.

- Further, the DISCOMs has to pay/receive charges for electricity not provided to it/availed by it.

Hence, it is requested to kindly investigate the matter and correct the scheduling as per actuals and take further necessary action for correction in REA and DSM accounts. Such occurrence in past also needs to be investigated.

It may kindly be taken up on urgent basis.

Yours faithfully
Sd/-
(Deepak Kumar)
Chief Engineer (Commercial)

North Bihar Power Distribution Company Limited

(Regd. Office : Vidyut Bhawan, Bailey Road, Patna)
CIN:- U40109BR2012SGC018920
(Commercial Department)

M.No: 9264437178
E-mail:- cecom2.nbpdcl@gmail.com
nbpdcl.pp.2021@gmail.com

Date:-.........................

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Sub.: Revision of Schedule by ERLDC from retrospective effect.

Sir,

With reference to above, it is found that actual schedule provided is modified with retrospective effect sometime. Recently such retrospective change in schedule has been observed in schedule from Ostro Kannada and Tuticorin Orange for 04/01/2022. The revision no. just after the midnight is 203 as per the ERLDC website. However, this scheduled has been changed vide revision no. 206 on 12/01/2022 at 15:37:04.

It can be noted that such revisions with retrospective effect will have financial implications in view of following:-

- The power drawl is monitored and controlled, if required to match the Schedule provided for each time block on continuous basis. However, any change in schedule with retrospective effect makes such monitoring and control of drawl with an aim to match the schedule a futile exercise.

- Further, the DISCOMs has to pay/receive charges for electricity not provided to it/availed by it.

Hence, it is requested to kindly investigate the matter and correct the scheduling as per actuals and take further necessary action for correction in REA and DSM accounts. Such occurrence in past also needs to be investigated. It may kindly be taken up on urgent basis.

Yours faithfully
Sd/-
(Deepak Kumar)
Chief Engineer (Commercial)

Memo No..............................　Dated..............................

Copy Forwarded to Chief Engineer (Commercial), SBPDCL for kind information and needful action.

Sd/-
(Deepak Kumar)
Chief Engineer (Commercial)

Annexure-C11

CIN NO-L40101HR1975GOI032564

एनएचपीसी लिमिटेड

NHPC Limited

ओ&एम प्रभाग / O&M Division
एनएचपीसी कार्यालय परिसर/ NHPC Office Complex
सैक्टर-33, फरीदाबाद/ Sector-33, Faridabad
हरियाणा - 121003 / Haryana-121003
Email-

NH/O&M/2022/GMC/17/ 68

पूर्वी क्षेत्रीय विद्युत समिति
Eastern Regional Power Committee
डायरी सं०/Diary No. 193
दिनांक/Date 13/06/2022
भारत सरकार/Govt. of India
14, गोल्फ क्लब रोड टालीगंज
14, Golf Club Road
कोलकाता-33, Kolkata-33

03/06/2022

The Member Secretary
ERPC
14, Golf Road, Tolley Ganj,
Kolkata 7000033.

विषय: माननीय केन्द्रीय विद्युत विनियामक आयोग (Hon'ble CERC) द्वारा जारी विचलन प्रभार तंत्र 2022 (Deviation Settlement Mechanism, 2022) के संदर्भ में ।

महोदय,

कृप्या माननीय केन्द्रीय विद्युत विनियामक आयोग, द्वारा जारी आदेश संख्या L-1/260/2021/CERC दिनांक 14 मार्च 2022 (प्रति सलग्न) का संदर्भ लें, जिसके माध्यम से विचलन प्रभार तंत्र एवं संबंधित मुद्दे, 2022 (Deviation Settlement Mechanism & related Matters, 2022) जारी किया गया है । उक्त विनियमन को लागू करने हेतु माननीय केन्द्रीय विद्युत विनियामक आयोग द्वारा अलग से आदेश जारी की जाएगी।

इस विचलन प्रभार तंत्र विनियामक का उद्देश्य निम्न में वर्णित है :

"These regulations seek to ensure, through a commercial mechanism that users of the grid do not deviate from and adhere to their schedule of drawal and injection of electricity in the interest of security and stability of the grid".

उपरोक्त के संबंध में यह बताना आवश्यक है कि, Generators द्वारा हमेशा मशीनों की परिचालन RLDC द्वारा प्राप्त Schedule के अनुरूप किया जाता है, लेकिन ग्रिड फ्रीक्वन्सी में अस्थिरता या कोई अप्रत्याशित घटना की वजह से IEGC के प्रावधानों के अनुसार Schedule से विचलन हो जाती है ।

इस संदर्भ में, प्रस्तावित विचलन प्रभार तंत्र 2022 पर एनएचपीसी की टिप्पणी अनुलग्नक -I में आपके अवलोकनार्थ संलग्न किया जाता है तथा माननीय केन्द्रीय विद्युत विनियामक आयोग द्वारा जारी विचलन प्रभार तंत्र एवं संबंधित मुद्दे, 2022 में Generators हेतु उपयुक्त प्रावधानों का संक्षिप्त विवरण अनुलग्नक -II में संलग्न किया जाता है ।

उक्त Regulations से संबंधित टिप्पणियों को माननीय उत्तरी क्षेत्रीय पावर समिति (NRPC) द्वारा Hon'ble CERC के संज्ञान में लाया जा सकता है ।

धन्यवाद,

भवदीय,

(राजेश शर्मा) 03/06

कार्यपालक निदेशक (ओ&एम)

SE (Commn.)

Annexure I

Comments on Final Regulations

1. **Regulation: 5 (1):"For a secure and stable operation of the grid, every grid connected regional entity shall adhere to its schedule as per the Grid Code and shall not deviate from its schedule".**

   As per above regulation, there is no provision to inject power in a time block against zero schedule, however, while synchronizing/de-synchronizing the machines, generators normally synchronize their machines just ahead of scheduled time block so as to ramp-up to achieve the desired schedule. Also during shutdown, generators generate power against zero schedule when machine ramps-down from GENERATION mode to STANDSTILL mode.In both the above cases, as per the new Mechansim Generator shall have to pay the charges as regulation does not permit to inject any power against zero schedule.

   It is pertinent to mention that, to address the above issues, Hon,ble CERC had issued an amendment vide order no. No.–L-1/(3)/2009-CERC dated 06 May 2016 (copy attached), which was called Central Electricity Regulatory Commission (Deviation Settlement Mechanism and related matters) (Third Amendment) Regulations, 2016, wherein, the following was amended.

   "3. Amendment of Regulation 5 of the Principal Regulations

   (2) Clause (iv) of Proviso to Regulation 5(1) of the Principal Regulations shall be substituted as under: "The charges for the deviation for the over-injection by the seller (except Renewable Rich State) in a time block in excess of 12% of the schedule or 150 MW, whichever is less, shall be zero, except in case of injection of infirm power, which shall be governed by clause (5) of this regulation:

   Provided that in case schedule of a seller (except Renewable Rich State) in a time block is less than or equal to 400 MW, the charges for the deviation for the over-injection in excess of 48 MW shall be zero".

   In view of above and considering the provisions/amendments issued by Hon'ble CERC for removal of difficulties in their Principal DSM regulations, it is requested that the situation of injection of power against zero schedule under above conditions may be seen and the clause may be reviewed accordingly.

2. **Regulation 8 (3)(b): The charges for deviation for drawal of start-up power before COD of a generating unit or for drawal of power to run the auxiliaries during shut-down of a generating station shall be payable at the normal rate of charges for deviation".**

   As per above regulation, Generators shall have to pay to the Deviation Pool Account @ normal rate for drawal of power against zero schedule to fulfill their auxiliaries requirement during shut down of units, whereas, the generators are being paid @ECR for its generation.

During lean season hydro generator operate only during peaking hours and during rest of the day the units remain under shutdown and may draw some power for running auxiliaries. As such, payment by generator @normal rate for meeting the auxiliary power requirements needs to be reviewed, which should be restricted upto ECR.

3. **Regulation 8(1): Charges for deviation payable to Deviation and Ancillary Service Pool Account (for a general seller other than an RoR generating station or a generating station based on municipal solid waste) for deviation by way of <u>over injection</u> (ii) @ 10% of the normal rate of charges for deviation beyond 2%.**

As per this Regulations, seller/Generator shall have to pay the charges for deviation @10% of the normal rate to Deviation and Ancillary Service Pool Account for deviation beyond 2% Deviation.

The unit capacity of hydro generating units varies from few MW to 250MW. In NHPC, the unit capacity varies from 20 MW to 180MW and the allowable limit of 2% is marginal in terms of MW and will work out to around 0.4MW to 3.6MW, which is very negligible. The load of the hydro generating unit is frequency dependent and marginal variation in load is beyond the control of the generator.

Further, as per Central Electricity Regulatory Commission (Indian Electricity Grid Code), regulations 2010 & its subsequent amendments, (clause 5.2.f. System Security Aspects), Hydro units of 25 MW and above shall have the capability of instantaneous picking upto 110 % of their MCR (Maximum Continuous Rating), when frequency falls suddenly. Moreover, as per order issued by NRLDC vide their letter no NRLDC/SO-117/721 dated 08/05/2018 during lean season/less inflow period, RLDCs shall not schedule the generating stations beyond normative ex-bus generation (Installed Capacity minus normative Auxiliary Consumption) corresponding to 100% of the installed capacity of the generating station. That means during lean season/less inflow period, there would be margin available to the RLDC, especially in peak period, from Ex-bus installed capacity up to 110% of the MCR of the generating stations or unit thereof, for getting primary response, when frequency falls suddenly in the Grid.

Further, there is no incentive proposed in the regulations for Primary response given by the generator in terms of supporting the Grid beyond 2%. Rather deviation beyond 2% in terms of over injection shall lead to penalty to the generating stations.

Thus, limiting deviation to 2% as mentioned in the Regulations needs to be reviewed considering the prevailing provisions in IEGC Regulations.

4. **Regulation 8(1): Charges for deviation in a time block by a seller shall be payable by such seller as under (For a general seller other than an RoR generating station or a generating station based on municipal solid waste), Deviation by way of <u>under injection</u>. The charges for deviation payable by the seller to Deviation and Ancillary Service Pool Account:**
   - @ the reference charge rate **up to 2% Deviation**
   - @ 120% of the normal rate of charges for deviation **beyond 2% Deviation and up to 10%.**
   - @ 150% of the normal rate of charges for deviation **beyond 10% Deviation.**

As per above regulations of Deviation settlement Mechanism, the generator shall pay to Deviation and Ancillary Service Pool Account during under injection. Further, the rate of charges payable by the generator is 120% of the normal rate and 150% of normal rate if deviation (under injection) occurs between 2% to 10% and beyond 10% respectively.

In this regard, it is submitted that response of the generating stations, during frequency variations depends upon droop setting of the Generating unit(s). When Grid frequency is higher especially beyond 50.5 Hz, generating stations are supposed to support the Grid by reduction of the generation based on the droop setting. Thus, supporting the Grid by under injection of generating stations, during high frequency is leading to the penalty (@ reference rate for deviation up to 2%, @ 120 % of the normal rate for deviation beyond 2% & upto 10% and @ 150% of normal rate of deviation beyond 10%), which may kindly be reviewed.

Further, it is fact that in-spite of carrying out the regular preventive/predictive maintenance of units, any untoward breakdown and tripping of unit can't be prevented as the same is beyond the control of Power Stations. Once unit is tripped, then as per Central Electricity Regulatory Commission (Indian Electricity Grid Code) (Sixth Amendment) Regulations, 2019, the request for revision in schedule or declared capability shall be effective w.e.f. 7th time block or 8th time block for the request received in odd time block and even time block respectively, as the case may be. As per the proposed DSM regulation, the penalty @150% of the normal rate of charges for deviation beyond 110% deviation shall be imposed on the seller (generator) till 7th/8th time blocks, which is a huge penalty and may kindly be reviewed.

5. **Regulation 8(1): Charges for deviation in a time block by a seller shall be payable by such seller as under (For a general seller being an <u>RoR generating station</u>). Deviation by way of over injection**

   "Zero"

   Provided that such seller shall be paid back for over injection up to [2% Deviation-general seller (in %)] @ the reference charge rate.

   As per this regulation, for RoR generating station, in case of Over Injection, Seller shall be paid back for over injection @the reference charge rate for deviation upto 2% deviation, however, there is no payment for over injection beyond 2% of deviation.

   The generation from RoR Stations is dependent on inflow. RoR hydro stations have limited storage capacity and accordingly, CERC has already considered these stations as 'Must Run" Power Stations.

   The proposed regulation provides zero charge in case of over injection beyond 2% and as such RoR stations are not being incentivised for using any excess inflow and the excess water may not be utilized as RoR stations have very limited storage capacity.

   In view of above the Clause may kindly be reviewed, if over injection occurs beyond 2% due to sudden increase in inflow.

6. **Regulation 8(3)(a): The charges for deviation for injection of infirm power shall be zero.**

   The revenue earned by generating company from supply of infirm power is adjusted in capital cost of the project which results in lower tariff and the beneficiaries get benefit by way of lower tariff for the project.

   The proposed Deviation Settlement Mechanism provides zero energy charges for infirm power, thus depriving the beneficiaries the benefit of lower tariff from the project.

7. **Clause 5 of Central Electricity Regulatory Commission (Deviation Settlement Mechanism and Related Matters) Regulations, 2022, is dealt as under:**

   "Adherence to Schedule and Deviation:

   (1) ***For a secure and stable operation of the grid, every grid connected regional entity shall adhere to its schedule as per the Grid Code and shall not deviate from it schedule.***

(2) ***Any deviation shall be managed by the Load Despatch Centre as per the Ancillary Services Regulations, and the computation, charges and related matters in respect of such deviation shall be dealt with as per the following provisions of these regulations".***

Hon'ble CREC issued a regulation vide their order No. RA-14026(11)/3/2019-CERC dated 31 January 2022 on Ancillary Services, Regulations, wherein, the following regulations are available for payment to generator against Secondary Ancillary Services:

(1) ***SRAS Provider shall be paid from the Deviation and Ancillary Service Pool Account, at the rate of their energy charge or compensation charge, as declared by the SRAS Provider, as the case may be, for the SRAS-Up MW quantum despatched for every 15 minutes time block, calculated as per clause (12) of Regulation 10 of these regulations.***

(2) ***SRAS Provider shall pay back to the Deviation and Ancillary Service Pool Account, at the rate of their energy charge or compensation charge, as the case may be, for the SRAS-Down MW quantum despatched for every 15 minutes time block, calculated as per clause (12) of Regulation 10 of these regulations. (3) SRAS Provider shall be eligible for incentive based on performance as per Regulation 12 of these regulations.***

Clause 12 **of Ancillary Services, Regulations** ***(Performance of SRAS Provider and incentive)***

(3) SRAS Provider shall be eligible for incentive based on the performance measured as per clause (2) of this Regulation and the 5-minute MWh data calculated for SRAS-Up and SRAS-Down as per clause (11) of Regulation 10 of these regulations and aggregated over a day, as under:

Actual performance vis-a-vis secondary control signal for an SRAS provider	Incentive Rate (Paise/KWH)
95% and above	(+)50
75% to below 95%	(+)40
60% to below 75%	(+)30
50% to below 60%	(+)20
20% to below 50%	(+)10
Below 20%	0

As per DSM, 2022 regulations, any deviation shall be managed by the Load Despatch Centre as per the Ancillary Services Regulations and further Ancillary Service Regulations has the provision for payment of SRAS @ of their ECR (Energy Charge Rate) and a performance related charges shall be paid to the generator based on their response with maximum rate @ 50paise/KWH, if performance is 95% and above.

Deviation Settlement Mechanism, 2022 regulations, provides the provision to impose penalty to the generator @ 120 % of the normal rate for deviation beyond 2% & upto 10% and @ 150% of normal rate of for deviation beyond 10%,in case of under-injection, whereas, the generator shall be paid only @ ECR against their ancillary support (SRAS). This may kindly be reviewed.

Annexure II

Deviation Settlement Mechanism 2022

Hon'ble CERC vide order No. L-1/260/2021/CERC Dated:14th March, 2022, issued the final Deviation Settlement Mechanism and Related Matters, Regulations, 2022. This regulation shall come into force on such date as may be notified by the Commission separately.

The main points related to generating stations in the final Deviation Settlement Mechanism, 2022 are detailed below:

1. Definition of Normal Rate of Charges for Deviations

   - *The normal rate of charges for deviation for a time block shall be equal to the Weighted Average Ancillary Service Charge (in paise/kWh) computed based on the total quantum of Ancillary Services deployed and the net charges payable to the Ancillary Service Providers for all the Regions for that time block:*

     Provided that for a period of one year from the date of effect of these regulations or such further period as may be notified by the Commission, ***the normal rate of charges for deviation for a time block shall be equal to the highest of [the weighted average ACP of the Day Ahead Market segments of all the Power Exchanges; or the weighted average ACP of the Real Time Market segments of all the Power Exchanges; or the Weighted Average Ancillary Service Charge of all the regions] for that time block****.....*

2. ***Charges for deviation payable to Deviation and Ancillary Service Pool account:***

   A. For a general seller **other than an RoR generating station** or a generating station based on municipal solid waste)

   Over Injection

   a) *Seller shall be paid back for over injection @ the reference charge rate (ECR) for deviation* ***up to 2% Deviation***
   b) *Seller shall have to pay the charges for deviation @10% of the normal rate to Deviation and Ancillary Service Pool Account for deviation* ***beyond 2% Deviation.***

   Under Injection (Charges for deviation payable by the seller to Deviation and Ancillary Service Pool Account)

   a) @ the reference charge rate **up to 2% Deviation**
   b) @ 120% of the normal rate of charges for deviation **beyond 2% Deviation and up to 10%.**
   c) @ 150% of the normal rate of charges for deviation **beyond 10% Deviation.**

   B. For a general seller being an **RoR generating station**

   Over Injection

   (1) *Seller shall be paid back for over injection @ the reference charge rate (ECR) for deviation up to 2% Deviation*

Under Injection (Charges for deviation payable by the seller to Deviation and Ancillary Service Pool Account):

a) @ the reference charge rate up to 2% Deviation
b) @ normal rate of charges for deviation beyond 2% Deviation and upto 10%
c) @ 110% of the normal rate of charges for deviation beyond 10% Deviation.

3. **The charges for deviation for injection of infirm power shall be zero.**

Annexure-C12.1

SUMMARY OF DEVIATION CHARGE RECEIPT AND PAYMENT STATUS

BILL UPTO 03-07-2022 (W-14 of 2022-2023)
Last Payment Disbursement Date - 20-07-2022

Figures in Rs. Lakhs

CONSTITUENTS	Net outstanding for 2021-22	Receivable	Received	Payable	Paid	Outstanding for 2022-23	Total Outstanding
BSPTCL	553.96908	6,446.41376	0.00000	2,162.08123	0.00000	4,284.33253	4,838.30161
JUVNL	4,372.21930	9,198.51553	0.00000	413.67229	0.00000	8,784.84324	13,157.06254
DVC	0.00000	3,528.49501	3,406.60766	363.26154	766.00757	524.63338	524.63338
GRIDCO	6.42843	19,835.85397	18,832.28736	1,391.18626	790.86595	403.24630	409.67473
WBSETCL	82.45475	14,241.84145	13,641.73260	941.76319	371.42099	29.76665	112.22140
Sikkim	956.99860	679.11656	0.00000	260.64581	0.00000	418.47075	1,375.46935
NTPC	0.00000	3,482.69014	3,264.75110	0.00000	0.04641	217.98545	217.98545
NHPC	0.00000	0.00000	0.00000	636.18354	636.18354	0.00000	0.00000
MPL	0.00000	104.83023	104.83023	149.54561	149.54561	0.00000	0.00000
APNRL	0.00000	226.30568	194.05304	89.02772	89.02772	32.25264	32.25264
CHUZACHEN	0.00000	0.00000	0.00000	90.75421	90.75421	0.00000	0.00000
NVVN-BD	0.00000	23.36139	23.36139	159.87232	159.87232	0.00000	0.00000
GMR	0.00000	67.43846	57.52497	216.53049	216.53049	9.91349	9.91349
JITPL	0.00000	642.15541	642.15542	98.30815	98.30815	-0.00001	-0.00001
TPTCL (Dagachu)	0.00000	1,239.65755	1,002.74259	0.00000	0.00000	236.91496	236.91496
JLHEP	0.00000	399.69994	193.22835	0.00000	0.00000	206.47159	206.47159
NVVN-NEPAL	0.00000	5,594.38913	5,594.38913	308.62837	308.62837	0.00000	0.00000
IBEUL	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
BRBCL	0.00000	433.56522	433.56522	43.39580	43.39580	0.00000	0.00000
PGCIL SASARAM	-0.01686	7.88429	7.65331	37.98400	37.98400	0.23098	0.21412
TUL (Teesta-III)	-0.02372	371.18233	355.03459	90.00523	90.00523	16.14774	16.12402
NERLDC	-411.85650	48,747.29987	32,415.03335	20,365.23823	19,948.18866	15,915.21695	15,503.36045
WRLDC	-42.74324	0.00000	0.00000	3,09,735.68341	2,94,904.77163	-14,830.91178	-14,873.65502
NRLDC	-4,591.25039	81,223.01062	72,059.79791	4,209.03291	4,209.03291	9,163.21271	4,571.96232
SRLDC	-335.82650	1,73,758.83118	1,45,330.86417	0.00000	0.00000	28,427.96701	28,092.14051
VAE	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
Dikchu	0.00001	40.11225	40.11225	81.98230	81.98230	0.00000	0.00001
PGCIL-Alipurduar	0.00000	10.66922	7.12882	2.97584	2.97584	3.54040	3.54040
Tashiding(THEP)	0.00000	271.82887	200.67049	25.21310	25.21310	71.15838	71.15838
OPGC	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
KBUNL	0.00000	172.92426	161.92189	35.85888	35.85888	11.00237	11.00237
NPGC	0.00000	411.73269	364.09100	181.29066	181.29066	47.64169	47.64169
NPGC-Infirm	0.00000	298.01341	298.01341	1,006.41355	1,006.41355	0.00000	0.00000
RONGNICHU	0.00000	10.07116	10.07116	106.74015	106.74015	0.00000	0.00000
BRBCL_U4_Infirm	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PTC Bhutan	0.00000	0.00000	0.00000	141.54024	141.54024	0.00000	0.00000
Total	**590.35296**	**3,71,467.88958**	**2,98,641.62141**	**3,43,344.81503**	**3,24,492.58428**	**53,974.03742**	**54,564.39038**

Receivable:	Receivable by ER	Payable:	Payable by ER POOL
Received:	Received by ER P	Paid:	Paid by ER POOL
'- ve'	Payable by ER pool	'+ ve'	Receivable by ER pool

Annexure-C12.2

Deviation Interest Bill due to delay payment

All figs in Rupees.

Sl No.	Constituent Name	Interest outstanding till Q4_2020-21	Interest Received by Pool against outstanding	Interest Paid by pool against Outstanding	Net Interest outstanding till Q4_2020-21
1	BSPTCL	91,05,608	91,05,608		0
2	DVC	23,718		23,718	0
3	GRIDCO	-2,79,466		2,79,466	0
4	JUVNL	4,34,61,973	4,34,61,973		0
5	Sikkim	11,76,865	11,76,865		0
6	WBSETCL	21,415	21,415		0
7	NHPC	-54,745		54,745	0
8	NTPC	0			0
9	APNRL	11,33,748	11,33,748		0
10	BRBCL	-1,316		1,316	0
11	JLHEP	1,28,853	1,15,968	12,885	0
12	CHUZACHEN	-3,119		3,119	0
13	GMR	1,73,96,828			1,73,96,828
14	IBEUL	26,75,383			26,75,383
15	JITPL	8,589	8,589		0
16	KBUNL	40	40		0
17	MPL	-33,428		33,428	0
18	NPGC-Infirm	0			0
19	NPGC	-10,953		10,953	0
20	NVVN-BD	24,603		24,603	0
21	NVVN-NEPAL	0			0
22	OPGC	24,209			24,209
23	PGCIL-Alipurduar	1,72,257	1,72,258		-1
24	PGCIL SASARAM	1,686	1,686		0
25	Tashiding(THEP)	1,57,661	1,57,661		0
26	Dikchu	28,701	28,701		0
27	TPTCL (Dagachu)	0			0
28	TUL (Teesta-III)	-1,134		1,134	0

'- ve' Payable by ER pool '+ ve' Receivable by ER pool

Note: Ind-bharath interest is calculated till 29.05.2019

RRAS interest details				
Constituents	Amount in ₹ Lacs	Interest Paid in 1st Quarter 2021-22	Balance	Payment Date
NTPC	-4.85430	4.85430	0.00000	16.06.2020
BRBCL	-0.60400	0.60400	0.00000	16.06.2020
KBUNL	-3.22746	3.22746	0.00000	16.06.2020
MPL	-2.22505	2.22505	0.00000	16.06.2020
NPGC	-0.79683	0.79683	0.00000	16.06.2020
Total	-11.70764	11.70764		

Annexure - C12.3

STATUS OF REACTIVE CHARGES

Annexure-III

BILL UPTO 03-07-2022 (W-14 of 2022-2023)

Name of Parties	Receivable Amount by pool	Received Amount by pool	Payable Amount by pool	Paid Amount by pool	Outstanding Amount Receivable(+Ve) / Payable by pool(-Ve)
BSPHCL	40959642	33250493	9886304	2485763	308608
JUVNL	48020781	0	0	0	48020781
DVC	11153012	8860836	166864	166864	2292176
GRIDCO	3054458	1941082	1807808	1807808	1113376
SIKKIM	5140091	4800000	357776	17685	0
WBSETCL	36671161	30380284	0	0	6290877

Receivable: Receivable by ER POOI Payable: Payable by ER POOL
Received: Received by ER POOL Paid: Paid by ER POOL
'- ve' Payable by ER pool '+ ve' Receivable by ER pool

Annexure -C13

Current Status of Letter of Credit (LC) amount against DSM charges for ER constituents

Figures in Lacs of Rupees

Sl No	ER Constituents	No. of weeks in which Deviation Charge payable	No of times payment was delayed during 2021-22	Total Deviation charges payable to pool during 2021-22	Average weekly Deviation Charge liability (C)/52 weeks	LC Amount 110% of (B)	Defaulting Weeks	Due date of expiry	Remarks
		(A)	(B)	(C)	(D)	(E)	(G)	(F)	(G)
1	Bihar State Power Holding Corporation Limited / बिहार	41	41	21320.74	410.01	451.02	All Weeks	13-11-2022	LC opened for Rs. 21353049.
2	Jharkhand State Electricity Board / झारखंड	44	44	7539.19	144.98	159.48	All Weeks	22-11-2022	LC opened for Rs. 6873783
3	SLDC - UI FUND - WBSETCL / पश्चिम बंगाल	49	2	11830.03	227.50	250.25	Week-4, 40	No Valid LC	
4	Power Deptt, Govt. of Sikkim / सिक्किम	41	41	2725.25	52.41	57.65	All Weeks	No Valid LC	
5	NTPC / एनटीपीसी	37	2	6994.96	134.52	147.97	Week-14, 22	No Valid LC	
6	Maithon Power Limited / मैथन	14	1	136.99	2.63	2.90	Week-4	No Valid LC	
7	Adhunik Power & Natural Resources Limited / अधुिनक शक्ति	20	19	322.87	6.21	6.83	All Weeks except Wk-27	No Valid LC	
8	Gati Infrastructure Private Limited / चुजाचेन	9	6	33.66	0.65	0.71	Week-5, 12, 14, 15, 29, 30	No Valid LC	
9	GMR Kamalanga Energy Limited / जीएमआर	1	1	42.36	0.81	0.90	Week-7	No Valid LC	
10	Jindal India Thermal Power Ltd. / जिंदल	26	5	1202.22	23.12	25.43	Week-21, 26, 29, 38, 41	No Valid LC	
11	DANS Energy Private Limited - Operation Retention Account / ड	49	26	1019.28	19.60	21.56	Week-1, 2, 3, 4, 5…	No Valid LC	
12	Powergrid Corporation Of India Limited-Sasaram / सासाराम	28	8	21.97	0.42	0.46	k-6, 16, 17, 18, 19, 20, 2	31-03-2023	LC opened for Rs. 46484
13	Sneha Kinetic Power Projects Pvt. Ltd./ दिकचू	15	1	82.48	1.59	1.74	Week-26	No Valid LC	
14	PGCIL-Alipurduar / अलीपुरदुआर	26	16	41.02	0.79	0.87	Week-3, 4, 6, 7, 9, 10…	31-12-2022	LC opened fro Rs 14629
15	Shiga Energy Private / शिगा ऊर्जा	44	26	789.57	15.18	16.70	Week-1, 2, 4, 9…	No Valid LC	
16	NABINAGAR POWER GENERATING CO. PVT LTD. / नबीनगर	16	1	607.86	11.69	12.86	Week-24	02-02-2023	LC opened for Rs 4736890
17	NABINAGAR POWER GENERATING CO. PVT LTD. - INFIRM	40	1	1151.76	22.15	24.36	Week-40	No Valid LC	
18	RONGNICHU HEP	24	6	110.97	2.13	2.35	Week-6, 7, 8, 10, 11, 15	No Valid LC	
19	PTC INDIA LTD.	6	1	198.04	3.81	4.19	Week-45	No Valid LC	

Annexure-C15

Fax: 03592 202927

Phones: 202706
PBX: 222908
222916

GOVERNMENT OF SIKKIM
POWER DEPARTMENT

No.68/P/SLDC/2022-23/66 Dated 30/05/2022

TO WHOM IT MAY CONCERN

Ref : 1.243/CE/EHV/RE/E&P/2017-18/820 Dated 26.09.2017

Reference to application No:SEPL/F-03/22-23/865 dated : 27/15/2022 regarding issuance of NOC for the scheduling of Power by ERLDC for the power generated by 2x48.5 MW Tashiding HEP, Power Department, Govt. Of Sikkim do hereby provide a No Objection Certificate for evacuation of Power generated by Tashiding HEP of Shiga Energy Private Limited through Interconnection with the Intra-State Transmission line of Power Department.

The Scheduling may be done by ERLDC and the power be evacuated further to the Inter State Transmission System till the time SAMAST framework is set up at Sikkim SLDC.

Assistant Engineer (SLDC)

Power Department

Govt. Of Sikkim

Assistant Engineer (SLDC)
Energy & Power Deptt.
Govt. of Sikkim

PBX: 222908
222916

GOVERNMENT OF SIKKIM
POWER DEPARTMENT

No. 02/GEN/SLDC/2015-16/466 Dated 23/05/2022

TO WHOM IT MAY CONCERN

Ref: 1. E&P letter No.243/CE/EHV/RE/E&P/2017 - 18/830 dated 12.01.2018
2. CERC Order dated 13.12.2021 issued for Petition no. 175/MP/2021

Reference to application No. GIPL/HO/2022 – 23/05 / 001 dated: 19/05/2022 regarding issuance of NOC for the scheduling of Power by ERLDC for the power generated by Chuzachen HEP, Power Department, Government of Sikkim do hereby provide a No Objection Certificate for evacuation of power generated by Chuzachen HEP of Gati Infrastructure Pvt. Ltd through interconnection with the Intra – State Transmission Line of Power Department.

The agreement signed on 14th November 2003 between Gati Infrastructure Ltd and Sikkim Power Development Corporation Ltd. (A Government of Sikkim Enterprise) shall stand in force.

The Scheduling may be done by ERLDC and the power be evacuated further to the Inter State Transmission System till the time SAMAST Framework is set up at SLDC, Sikkim.

Executive Engineer (SLDC)

Executive Engineer
Power Department
Govt. of Sikkim, Gangtok

भारत सरकार
Government of India
विद्युत मंत्रालय
Ministry of Power
पूर्वी क्षेत्रीय विद्युत समिति
Eastern Regional Power Committee
14 गोल्फ क्लब रोड टालीगंज, कोलकाता-700033

सत्यमेव जयते

Azadi Ka Amrit Mahotsav

Tel. No.: 033-24239651,24239659 FAX No.:033-24239652, 24239653 Web: **www.erpc.gov.in**

No.: ERPC/TP/Meeting/ 517 Data: 18.07.2022

To

As per Distribution List

Sub: Minutes of special meeting held on 01.06.2022 to discuss the proposal of strengthening of transmission/Distribution network of DVC-reg

Sir,

Please find enclosed the minutes of special meeting on **"proposal of strengthening of transmission/Distribution network of DVC"** held on 01.06.2022 through MS Teams online platform for your kind information & necessary action.

Observations, if any, may please be forwarded to this office at the earliest.

Yours faithfully,

18.7.2022

(N.S. Mondal)
Member secretary

List of Addresses:

1. Executive Director, ERLDC
2. Chief Engineer(SPE), DVC
3. Chief Engineer(CPD), WBSETCL
4. General Manager, CTUIL
5. GM, SLDC, JUSNL
6. DGM, STU, JUSNL
7. DGM, C& M, JUSNL

Minutes of Special Meeting to discuss Proposal for Strengthening of T& D Network of DVC held on 01.06.2022 through MS Teams online platform.

List of participants is at **Annexure-I.**

Member Secretary, ERPC welcomed all the distinguished participants of STUs, CTU & ERLDC. He informed that as per decision of 45th TCC/ERPC meeting held on dated 25.03.22 &26.03.22 respectively, the meeting has been convened to discuss the proposal for strengthening of transmission & distribution network of DVC to meet the present and future load demands in their system. He further informed that the portion related to ISTS would be discussed at Monthly CMETS Meetings organized by CTU and the Intra state development projects would be discussed for its requirement at ERPC level. Accordingly, he requested all the members to discuss the intra-state part of the DVC proposal in the meeting.

DVC representative stated that they had submitted the proposal through a synopsis report as per the load flow studies carried out in PSSE 35.2 software considering the expected load growth by 2026-27 as per the application received from the Consumers and the connectivity clearance issued to the Consumers. The report was circulated to all the members well in advance. He added that the ISTS part of the proposal have already been discussed and agreed in the 6th Consultation Meeting for Evolving Transmission Scheme in Eastern Region held on 29.04.22.

<u>INTRA STATE PROPOSALS BY DVC</u>

DVC presented the overall scheme along with the Intra State proposals for strengthening of DVC Transmission and Distribution Network to the Members present. The proposal submitted by DVC is attached at Annexure-II.

Salient points of discussion were as follows:

1. NEW SUB STATIONS

A. <u>220/33 KV Ramgarh 2B Substation:</u>

<u>Connectivity</u>:

(i) LILO of ISTS 220 KV S/C Ramgarh-Ranchi line- agreed in 6th CMETS, dtd.29.04.22

(ii) LILO of 220KV S/C MTPS-Ramgarh line- agreed in 6th CMETS, dtd.29.04.22

<u>Power Transformers:</u>

(i) 2x80MVA,220/33 KV Power Transformer and associated bay

<u>33KV Feeder Bays</u>

(i) 4 No's 33KV Feeder Bays

.

B. 220/33 KV Panagarh Substation:

Connectivity:

(i) Single Circuit LILO of 220KV Parulia –Burdwan line and associated bays

Power Transformers:

(i) 02 nos. 220/33KV, 80 MVA Power Transformer and associated bays

33KV Feeder Bays:

(i) 4 No's 33KV Feeder Bays

C. 132/33KV Demotand Substation:

Connectivity:

(i) Single Circuit LILO of 132KV Barhi-Hazaribagh line and associated bays

Power Transformers:

(i) 02 nos. 132/33KV, 50 MVA Power Transformer and associated bays and feeders

Distribution Transformer:

(i) 02 nos. 33/11KV, 12.5MVA Distribution Transformer and associated bays

33KV Feeder Bays:-

(i) 4 No's 33KV Feeder Bays

11KV Feeders Bays:-

(i) 4 No's 11KV Feeder Bays

D. 33/11 KV Thamb Receiving Station:

Connectivity:

(i) 33KV D/C KTPS- Thamb line and associated bays on 132KV Towers to meet the upcoming Industrial load growth in the Region.

Distribution Transformer:

(i) 02 nos. 33/11KV, 12.5MVA Distribution Transformer and associated bays

33KV Feeder Bays:

(i) 4 No's 33KV Feeder Bays

11KV Feeders Bays:-

(i) 4 No's 11KV Feeder Bays

2. NEW LINES CONNECTIVITY

A. **LILO of S/C 132 KV CTPS-Gola at Biada Substation and associated bays** are proposed to convert the 132KVconnectivity of the Substation from radial to ring main and subsequent improvement in reliability of the system.

B. **B. LILO of D/C 132 KV Barhi- KTPS at Tilaya Solar Plant (300 MW at 132KV) alongwith its associated bays** are proposed to evacuate the solar power. The same line is also proposed for reconductoring with HTLS to evacuate such huge volume of power.
Matter in connection to the healthiness of the Towers were discussed and it was conveyed that maintaining healthiness/ strengthening of Towers would be under the contractual obligation and the work would be done in such a fashion, so that the life of the towers are further enhanced by another 35 Years.

C. **LILO of D/C 132 KV Ramkanali-PHS at Panchet Solar Plant (75 MW at 132KV) alongwith its associated bays** are proposed to evacuate the solar power.
As per the planning criteria, N-1 contingency in case of Solar has not been considered.

D. **LILO of 132KV S/C Ramkanali B-Jamuria(presently CTPS-Jamuria) at Ramkanali S/s and associated bays** are proposed for better reliability of the **System.**

E. **2nd circuit LILO of 132KV S/C MHS-PHS line at Kumardubi S/s and associated bays** are proposed to avoid overloading of MHS- Kumardubi line and to improve the system reliability.

F. **Conversion of Sindri S/s Connection from Radial to Grid by shifting connectivity of 132KV D/C MHS–Patherdih line from Patherdih S/s to Sindri S/s** is proposed to enhance the reliability of the system. After conversion, the 132KV D/C lines will be MHS-Sindri line.

3. NEW 220/132KV ATR/ICT AUGMENTATION

Addition of Following ICTs are proposed to cater the load growth and to overcome the congestion in the valley region and also to suffice N-1 contingency situations:

A. **01 no. 220/132KV ,200 MVA ICT at Barjora S/s** along with associated 220KV & 132KV Bay's.

B. **01 no. 220/132KV ,200 MVA ICT at Ramgarh S/s** along with associated 220KV & 132KV Bay's.

C. **<u>01 no. 220/132KV ,200 MVA ICT at CTPS</u>** along with associated 220KV & 132KV Bay's.

D. **<u>01 no. 220/132KV ,200 MVA ICT at Kalyaneswari S/s</u>** along with associated 220 KV & 132KV Bay's.

E. **<u>01 no. 220/132KV ,200 MVA ICT at KTPS S/s</u>** along with associated 220KV & 132 KVBay's.

F. **<u>01 no. 220/132KV ,200 MVA ICT at Giridih S/s</u>** along with associated 220KV & 132KV Bay's.

4. RECONDUCTORING OF TRANSMISSION LINES BY HTLS

Reconductoring of the Transmission lines with HTLS proposed to cater the load growth and to overcome the congestion in the valley region and also to suffice N-1 contingency in the region are mentioned below:

A. **<u>132 KV D/C DTPS-Jamuria line</u>** -66 CKM

B. **<u>132 KV D/C Koderma TPS –Koderma Radial Line</u>**- 36.6 CKM

C. **<u>132 KV D/C Koderma TPS – Barhi line</u>** - 40.16CKM

D. **<u>Proposed 132KV D/C Ramkanali B–Ramkanali line</u>** – 66 CKM(Approx)

E. **<u>132 KV S/C Ramkanali - Jamuria line</u>** - 53 CKM

F. **<u>132KV D/C MHS-Sindri–</u>** 88 CKM

G. **<u>Proposed 132 KV D/C Gola B-Gola</u>**- 20 CKM

H. **<u>132 KV D/C Ramgarh-Patratu</u>**- 48 CKM

I. **<u>220KV D/C DSTPS-DTPS</u>**- 23.6 CKM

5. **NEW POWER TRANSFORMER**

The following power transformers are required to cater the load growth at 33 KV level at different Substation and also to suffice N-1 contingency:

A. **<u>1x220/33KV,80 MVA transformer at Durgapur S/s and associated 220KV & 33 KV Bays</u>** (existing capacity 290 MVA & present load at 33 KV-214 MVA)

B. **<u>1x220/33KV,80 MVA transformer at MTPS A and associated 220KV & 33 KV Bays</u>** (existing capacity 160 MVA & present load at 33KV - 106 MVA)

C. **<u>1x220/33KV,80 MVA transformer at Ramgarh S/s and associated 220KV & 33</u>**

KV Bays (existing capacity 100 MVA and present load at 33KV -99MVA)

D. **1x132/33KV,80 MVA transformer at MHS and associated 132KV and 33 KV Bays** (existing capacity 100 MVA and present load at 33KV- 78 MVA)

E. **1x132/33KV,80 MVA transformer at Koderma S/s and associated 132KV and 33 KV Bays** (existing capacity 130 MVA and present load at 33 KV- 79 MVA)

F. **1x132/33KV,80 MVA transformer at Barhi S/s and associated 132KV and 33 KV Bays** (existing capacity 130 MVA& present load at 33 KV- 69.6 MVA)

G. **1x132/33KV,80 MVA transformer at Biada S/s and associated 132KV and 33 KV Bays** (existing capacity 160 MVA & present load at 33KV- 109.75 MVA)

Observation of ERPC Secretariat:

Member Secretary ERPC appreciated the proposals of DVC towards strengthening of T&D Network in their command area. With regard to the proposal, the following observations were made by ERPC Secretariat:

1. Matter in connection to the healthiness of the Towers were discussed. The transmission lines for which reconductoring has been proposed & life of the line is more than 35 years, health assessment of the associated towers shall be carried out to assess the healthiness of the lines. If required, strengthening/augmentation shall be done to enhance the life of the towers.

   DVC conveyed that maintaining healthiness/ strengthening of Towers would be under the contractual obligation and the works relating transmission line augmentation/ connectivity would be done in such a fashion, so that the life of the towers may further be enhanced by another 35 Years.

2. Single Circuit of LILO of 132KV CTPS-Gola line at Biada S/s would be sufficient to cater the upcoming load growth at Biada instead of D/C LILO of CTPS-Biada line.
3. Single Line Diagram is to be modified as per proposed plans and DVC was requested to submit the copy of the same. Further, a comprehensive chart may be prepared by DVC regarding the proposals.

MS, ERPC requested ERLDC, CTU and other STUs to present their views regarding the mentioned proposals of DVC.

Observation of ERLDC:

As per ERLDC, the proposals submitted by DVC are found to be in order as per their study. Besides, they have studied for N-1 contingency situations and found a few lines/equipments which are not satisfying N-1 Contingencies and DVC has stated that depending upon the commissioning of new Substation/Equipments/Lines and loadings on equipments/lines, suitable protection scheme will be planned in future. The study report of ERLDC is attached in Annexure-III.

ERLDC representative informed that study was conducted at their end on base case scenario as submitted by DVC. The study result & observations and the proposed scheme submitted by DVC are found to be generally in order. Further it was viewed that the study result indicates overloading of some of the lines/transformers mainly at 132 kV level during n-1-1 as well as n-1 contingency scenario. The observation of ERLDC on DVC proposal is attached at Annexure-II.

DVC representative stated that depending upon the commissioning of new Substation/Equipments/Lines and loadings on equipments/lines, suitable protection/redundancy scheme will be planned in future wherever it is required.

Observation of CTU:

CTU has already provided their views in the minutes of 6th CMETS meeting after studying the complete Inter & Intra schemes proposed by DVC. They did not have any comment on the present intra-state proposals of DVC.

Observation of JUSNL:

JUSNL representative conveyed their apprehension towards duplication of transmission system in areas wherein DVC and JUSNL both are supplying to consumers. He informed that in areas like Gola, Ramgarh & Giridih, JUSNL is already establishing new transmission schemes after due approval from CEA and further apprehended that the new system may get underutilized in case of implementation of DVC proposals in those areas.

DVC representative stated that strengthening of their existing system is required to fulfill present load demand and committed demand (for which connectivity clearance is already granted) with fulfilling of n-1 criteria. The demand growth is mostly industrial load within DVC command area.

Member Secretary stated that the transmission planning should be made keeping in view load growth projection in these areas and optimal utilization of assets of JUSNL as well as DVC.

Observation of WBSETCL:

WBSETCL representative expressed no objection in the above-mentioned proposal of DVC**.**

Conclusion:

After detailed discussion, it was concluded that the proposal presented by DVC are generally in order with few observation/modification as given below:

1. *Health assessment & necessary rectification of associated towers where the lines have exhausted their design life & reconductoring has been proposed.*
2. *LiLo of S/C of 132 kV CTPS-Gola B at Biada S/s instead of Lilo of D/c of 132 kV CTPS-Gola B line.*
3. *JUSNL may discuss with DVC regarding JBVNL load growth projection and completed/under execution transmission scheme in the common command area keeping in view optimal utilization of assets.*

The meeting was ended with a vote of thanks to the Chair.

****

Annexure-I

List of participants who attended the meeting physically at ERPC, Kolkata:

Sl No.	Name & Designation	Organisation
1	N.S. Mondal, Member Secretary	ERPC
2	S. Kejriwal, Suptd. Engineer	ERPC
3	P. P. Jena, Executive Engineer	ERPC
4	Jayanta Dutta, Chief Engineer(Engg)	DVC
5	Swarup Kumar Pal, SDE(OS &U)	DVC

List of participants who joined through online mode:

Name	**Joining Time**
ERPC Kolkata	6/1/22, 11:26:42 AM
Manish Ranjan Keshari-CTU (Guest)	6/1/22, 11:26:47 AM
Saurav Kr Sahay, ERLDC	6/1/22, 11:31:19 AM
CTU -2	6/1/22, 11:31:20 AM
Pritam Mukherjee, ERLDC	6/1/22, 11:31:39 AM
S. Ghosh, WBSETCL (Guest)	6/1/22, 11:31:50 AM
ABHILASH THAKUR, CTU	6/1/22, 11:33:40 AM
AMIT KUMAR (Guest)	6/1/22, 11:36:40 AM
Ajit Kumar, JUSNL	6/1/22, 11:38:32 AM
JUSNL (Guest)	6/1/22, 11:39:21 AM
Rajesh Kumar (Guest), CTU	6/1/22, 11:41:41 AM
GM SLDC Ranchi (Guest)	6/1/22, 11:49:39 AM
Saibal Ghosh, ERLDC	6/1/22, 11:53:16 AM
CET-JUSNL (Guest)	6/1/22, 12:03:31 PM
STU, Jharkhand	6/1/22, 12:19:15 PM
Atilesh Gautam	6/1/22, 12:21:25 PM

SUMMARY OF RRAS CHARGE RECEIPT AND PAYMENT STATUS

BILL UPTO 03-07-2022 (W-14 of 2022-2023)
Last Payment Disbursement Date 20.07.22

Figures in Rs. Lakhs

CONSTITUENTS	Receivable	Received	Payable	Paid	Outstanding
NTPC	2750.98633	1593.75414	1797.90093	781.95654	141.287800
MPL	245.74006	202.40256	97.08189	53.74439	0.000000
BRBCL	247.72797	139.78119	549.84607	483.5576	41.658310
KBUNL	55.60151	16.19225	281.12397	238.0095	-3.705210
NPGC	115.90046	13.38738	253.31249	162.70939	11.909980
TOTAL	**3415.95633**	**1965.51752**	**2979.26535**	**1719.97742**	**191.15088**

Receivable: Receivable by ER POOL
Received Received by ER POOL
Payable Payable by ER POOL
Paid Paid by ER POOL
"- ve" Payable by ER pool
"+ ve" Receivable by ER pool

SUMMARY OF AGC CHARGE RECEIPT AND PAYMENT STATUS

BILL UPTO 03-07-2022 (W-14 of 2022-2023)
Last Payment Disbursement Date 20.07.22

Figures in Rs. Lakhs

CONSTITUENTS	Receivable	Received	Payable	Paid	Outstanding
NTPC	1654.38275	1654.38275	0.00000	0.00000	**0.00000**
NHPC	0.92470	0.92470	4.93270	4.93270	**0.00000**
MPL	928.68111	928.68111	0.00000	0.00000	**0.00000**
KBUNL	83.53935	83.53935	0.00000	0.00000	**0.00000**
NPGC	277.40975	277.40975	38.80104	38.80104	**0.00000**
TOTAL	**2944.93766**	**2944.93766**	**43.73374**	**43.73374**	**0.00000**

Receivable: Receivable by ER POOL
Received Received by ER POOL
Payable Payable by ER POOL
Paid Paid by ER POOL
"- ve" Payable by ER pool
"+ ve" Receivable by ER pool

Annexure - C17.2

DETAILS OF DISBURSEMENT TO POWER SYSTEM DEVELOPMENT FUND

Sl No	Nature of Amount	Amount transferred to PSDF (Rs in Lac)	Date of Disbursement		Remarks
1	**Opening Balance (upto 31.03.2019)**	**95896.17**			
2	Reactive Energy Charge	105.79	04.04.19		Reactive Charges_18-19
3	Reactive Energy Charge	287.48	03.05.19		Reactive Charges_18-19 & 19-20
4	Reactive Energy Charge	129.70	03.06.19		Reactive Charges_19-20
5	Reactive Energy Charge	207.84	04.07.19		Reactive Charges_19-20
6	Reactive Energy Charge	94.92	02.08.19		Reactive Charges_19-20
7	Reactive Energy Charge	188.54	02.09.19		Reactive Charges_19-20
8	Surplus DSM amount transferred	32210.52	24.09.19		DSM Charges_19-20
9	Reactive Energy Charge	173.06	01.10.19		Reactive Charges_19-20
10	Reactive Energy Charge	273.15	01.11.19		Reactive Charges_19-20
11	Reactive Energy Charge	401.10	04.12.19		Reactive Charges_19-20
12	Reactive Energy Charge	252.54	02.01.20		Reactive Charges_19-20
13	Reactive Energy Charge	148.66	07.02.20		Reactive Charges_19-20
14	Reactive Energy Charge	205.22	04.03.20		Reactive Charges_19-20
15	Bank interest from Reactive acct	0.22	03.04.20		Bank interest from Reactive acct
16	Reactive Energy Charge	843.03	03.06.20		Reactive Charges_19-20 & 20-21
17	Reactive Energy Charge	507.80	07.07.20		Reactive Charges_17-18,18-19 & 20-21
18	Reactive Energy Charge	309.41	06.08.20		Reactive Charges_17-18,18-19 & 20-21
19	Reactive Energy Charge	83.24	02.09.20		Reactive Charges_19-20 & 20-21
20	Bank interest of DSM A/C-TDS portion	251.65	18.09.20		Bank interest TDS portion transferred from POSOCO,CC
21	Bank interest of DSM A/C-TDS portion	15.65	22.09.20		Bank interest TDS portion transferred from POSOCO,CC
22	Reactive Energy Charge	118.86	06.10.20		Reactive Charges_ 20-21
23	Reactive Energy Charge	101.43	04.11.20		Reactive Charges_ 20-21
24	Reactive Energy Charge	82.35	04.12.20		Reactive Charges_ 20-21
25	Reactive Energy Charge	500.95	06.01.21		Reactive Charges of 19-20 & 20-21
26	Reactive Energy Charge	92.51	03.02.21		Reactive Charges of 19-20 & 20-21
27	Reactive Energy Charge	50.23	04.03.21		Reactive Charges of 19-20 & 20-21
28	Reactive Energy Charge	32.15	07.04.21		Reactive Charges of 19-20 & 20-21
29	Reactive Energy Charge	39.60	05.05.21		Reactive Charges of 19-20 & 20-21
30	Reactive Energy Charge	18.96	01.06.21		Reactive Charges of 20-21 & 21-22
31	Reactive Energy Charge	392.25	12.07.21		Reactive Charges of 20-21 & 21-22
32	Reactive Energy Charge	214.22	22.07.21		Reactive Charges 20-21
33	Addl. Dev	392.94	25.08.21		DSM Charges of 19-20 received from Jharkhand
34	Addl. Dev	5.99	03.09.21		DSM Charges of 19-20 received from Jharkhand
35	Reactive Energy Charge	330.73	09.09.21		Reactive Charges 21-22
36	Addl. Dev	1334.98	23.09.21		DSM Charges of 20-21 received from Bihar
37	Addl. Dev	500.00	27.09.21		DSM Charges of 20-21 received from Bihar
38	Addl. Dev	1500.00	29.09.21		DSM Charges of 20-21 received from Bihar
39	Addl. Dev	500.00	01.10.21		DSM Charges of 20-21 received from Bihar
40	Addl. Dev	1000.00	05.10.21		DSM Charges of 20-21 received from Bihar
41	Addl. Dev	402.60	05.10.21		DSM Charges of 20-21 received from Jharkhand
42	Reactive Energy Charge	131.06	07.10.21		Reactive Charges 21-22
43	Addl. Dev	1000.00	22.10.21		DSM Charges of 20-21 received from Bihar
44	Addl. Dev	1000.00	26.10.21		DSM Charges of 20-21 received from Bihar
45	Addl. Dev	539.21	28.10.21		DSM Charges of 20-21 received from Bihar
46	Reactive Energy Charge	224.71	03.11.21		Reactive Charges 21-22
47	Reactive Energy Charge	366.26	03.12.21		Reactive Charges 21-22
48	Reactive Energy Charge	5.34	09.12.21		Interest Amount received in Reactive Account
49	Addl. Dev	489.57	04.01.22		DSM Charges of 20-21 received from Jharkhand
50	Reactive Energy Charge	449.70	04.01.22		Reactive Charges 21-22
51	Reactive Energy Charge	547.41	04.02.22		Reactive Charges 21-22
52	Addl. Dev	7182.01	08.02.22		Excess amount after clearing Wk-43
53	Addl. Dev	103.38	28.02.22		DSM Charges of 20-21 received from Jharkhand and POSOCO CC (REC)
54	Reactive Energy Charge	22.29	04.03.22		Reactive Charges 21-22
55	Reactive Energy Charge	978.22	08.03.22		Reactive Charges 21-22
56	Reactive Energy Charge	502.63	04.04.22		Reactive Charges 21-22
57	Addl. Dev	13586.90	02.05.22		Addl Dev Charge 21-22
58	Reactive Energy Charge	91.68	02.05.22		Reactive Charges 21-22
59	Addl. Dev	323.73	17.05.22		DSM Charges of 21-22 received from Jharkhand
60	Addl. Dev	223.19	31.05.22		DSM Charges of 21-22 received from Jharkhand
61	Addl. Dev	17070.56	02.06.22		DSM charges
62	Reactive Energy Charge	104.78	02.06.22		Reactive Charges 21-22
63	Addl. Dev	197.68	24.06.22		DSM Charges of 21-22 received from Jharkhand
64	Addl. Dev	32.98	24.06.22		DSM Charges of 21-22 received from DVC (Bhutan)
65	Addl. Dev	200.00	28.06.22		DSM Charges of 21-22 received from Jharkhand
66	Addl. Dev	200.00	30.06.22		DSM Charges of 21-22 received from Jharkhand
67	Reactive Energy Charge	491.14	08.07.22		Reactive Charges 21-22 received from Bihar
68	Addl. Dev	200.00	14.07.22		DSM Charges of 21-22 received from Jharkhand
69	Addl. Dev	900.00	20.07.22		DSM Charges of 21-22 received from Sikkim and Bihar
	Total	**187360.86**			

Annexure-C18.1

Detailed Procedure
For
Estimation of the Requirement
of
Secondary Reserve Ancillary Service (SRAS)
and
Tertiary Reserve Ancillary Service (TRAS)
at
Regional Level

Background

- Regulation 6(1) of the CERC (Ancillary Services) Regulations, 2022
  - Interim methodology for estimation of reserves

- Reserve Estimation
  - NLDC (Nodal Agency) in coordination with RLDCs and SLDCs
  - Quantum of requirement of Secondary Reserves for SRAS and Tertiary Reserves for TRAS at the regional level
  - Factor the reserves for each state control area
  - Based on methodology as specified in the IEGC (Draft)
  - Publication of reserve requirement on the website

Time frames for Reserve Estimation

- Year-ahead
- Quarter-ahead
- Week-ahead

Resource Adequacy/LGBR

Resource Adequacy & Fuel tie-ups

Operational planning/Unit Commitment

- Day-ahead
- Intra-day

Reserve Procurement

Incremental Procurement

Basis of Estimation

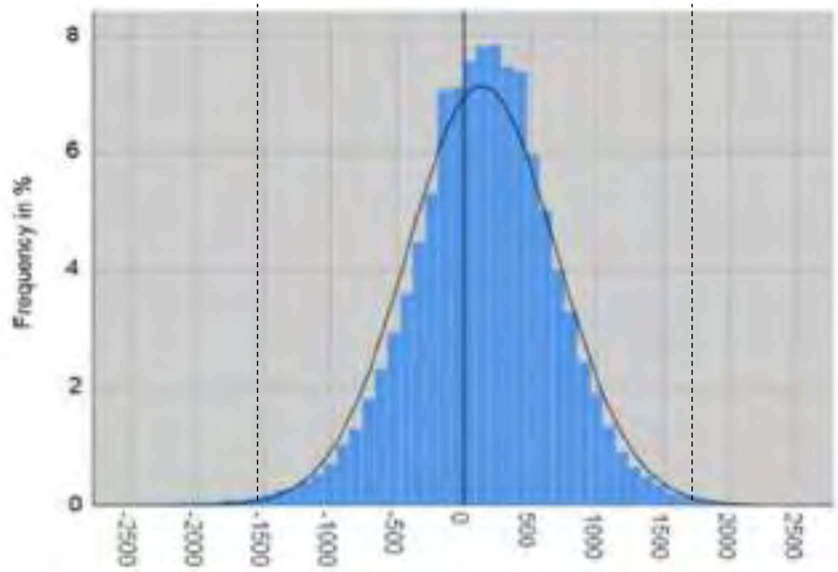
Influencing Factors

- Load forecast error
- Wind Forecast Error
- Solar Forecast Error
- Forced outage
- Schedule leaps

Distribution of Area Control Error

99 percentile value of ACE

Required balancing reserve



Roles

- Nodal Agency
  - To estimate the quantum of requirement of SRAS & TRAS
  - To assess and declare Frequency Bias Coefficient (Bf)
- SLDCs
  - To furnish data in the stipulated formats to the Nodal Agency for estimation of quantum of requirement of SRAS & TRAS.
  - To maintain reserves
    - As estimated by Nodal Agency or
    - As per estimation carried out by SLDC (as per IEGC or State Grid Code)

Reserves in Indian Power System

Reserve	Start of activation	Full Availability/ deployment	Ability to sustain the full deployment
Primary Response	Instantaneous as soon as frequency crosses the dead band	Within 30 sec	5 min
Secondary control Reserve	within 30 sec	Within 15 Min	30 min or till replaced by Tertiary Reserves
Tertiary control Reserve	Within 15 Min		60 min

Area Control Error (ACE)

- "ACE" means the instantaneous difference between a control area's net actual interchange and net scheduled interchange, taking into account the effects of frequency bias and correction of measurement errors.
- Area Control Error (ACE) for each control area to be calculated based on telemetered values and external inputs

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

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

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

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

Fa = Actual system frequency in Hz

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

Offset = Provision for compensating errors; default value zero.

Interpretation of ACE

- ACE is ‘positive’ means that the control area has surplus generation and the control area’s internal generation has to be backed down.
  - Example ACE = ((-800) – (- 1050)) - 10 * (-200) * (50.07 – 50) = 390

- ACE is ‘negative’ means the control area is in deficit and the control area’s internal generation has to be increased.
  - Example ACE = ((-1300) – (-1050)) - 10 * (-200) * (49.90 – 50) = - 270

Detailed methodology to be followed by Nodal Agency for calculation and monitoring of Area Control Error (ACE) *(Annexure – 1)*

Resolution of Data

- 10 second data to be used for ACE computation for reserve estimation
  - Frequency
  - Actual interchange

- Frequency Bias Coefficient (Bf) used based on median FRC during previous FY

- Peak Demand and Intra-state generation at time of peak demand during previous FY

10 second resolution captures contingency events and primary response under the AGC time frame.

Primary reserves to be freed up by SRAS

Data to be furnished by SLDCs

- **Year Ahead Basis** – For reserve estimation for the next financial year (FY+1), the data for the previous calendar year shall be furnished by 15th January of the current financial year (FY) (Format – RAS1)
  - *(Illustration: If the assessment is being carried out for FY 2022-23, the data for the period 1st Jan 2021 to 31st December 2021 has to be provided by 15th January, 2022)*

- **Quarter Ahead Basis** – For reserve estimation of the next quarter (Q+1) , the data for the similar quarter (Q-3) of the previous year shall be furnished by 15th day of the first month of current quarter (Q)(Format – RAS2)
  - *(Illustration: If the assessment is being carried out for Q2 of FY 2022-23 i.e. 01st July – 30th September, 2022, the data for Q2 of FY 2021-22 i.e. 01st July – 30th September 2021 has to be provided by First Month of Q1 of FY 2022-23 i.e. 15th April, 2022)*

Assessment by Nodal Agency

- **Week-Ahead Basis**
  - For weekly reserves requirement computation for the next week (W+1), data for the past four weeks (W-1, W-2, W-3, W-4) and same week (W+1) of the last year shall be used.
- **Day-Ahead Basis**
  - For the day ahead reserve estimation, last seven days data shall be used.
- **Real Time Basis**
  - For incremental requirement based on Availability of reserves on day ahead basis, real time system conditions, load/RE forecast errors, load generation balance, weather, contingencies, congestion and other related parameters.

Estimation of Reserves (Primary)

- CERC order dated 13th October, 2015 (Petition no. 11/SM/2015)
  - Envisaged loss of complete power station as a credible contingency for maintaining primary reserve.
- Most credible reference contingency for maintaining primary reserve, presently considered in the Indian power system
  - Outage of largest power plant/sudden load throw-off of 4500 MW

➢ On 12^{th} March 2014 at 19:22 hrs, there was outage of CGPL Mundra triggered by tripping of all evacuation lines, which resulted in a generation loss of 4030 MW

➢ On 28^{th} May 2020, inclement weather resulted in tripping of Satna, Sasan and Vindhyachal Pooling stations. Consequently, there was an aggregate loss of 5346 MW at Sasan, Vindhyachal NTPC Stage IV & V, and Rihand Stage III generating stations.

Estimation of Reserves (Secondary) (1 of 3)

- The positive (Up Reserve) and negative (Down Reserve) secondary reserve capacity requirement on regional basis would be computed
  - 99 percentile of negative and positive ACE respectively of that region for year ahead, quarter ahead and week ahead
- The 99 percentile of the positive and negative ACE of each state control shall be computed and aggregated at regional level.
- This shall be scaled using 99 percentiles of the regional ACE to factor diversity at regional level
- The scaled values of 99 percentile of the state ACE shall be used to arrive at the reserve requirement at Inter-state and Intra-state levels.

Estimation of Reserves (Secondary) (2 of 3)

- The drawl by the respective state and its internal-generation at the time of peak demand during the period under consideration shall be used for apportionment of the reserve requirement.
- The intra state reserves shall be in proportion to the contribution of internal generation at the time peak demand.
- The Inter-state reserves shall be in proportion to the drawl from the grid at the time of peak demand.
- The state level requirement shall be aggregated to arrive at the regional and all India reserve requirement.

Estimation of Reserves (Secondary) (3 of 3)

- The all-India total of positive (and negative) secondary reserves capacity requirement on regional basis shall be equal to the reference contingency or secondary reserve capacity requirement as computed above, whichever is higher.
- If the all-India reserve requirement is less than the reference contingency such additional reserves shall be considered in the regional requirement.

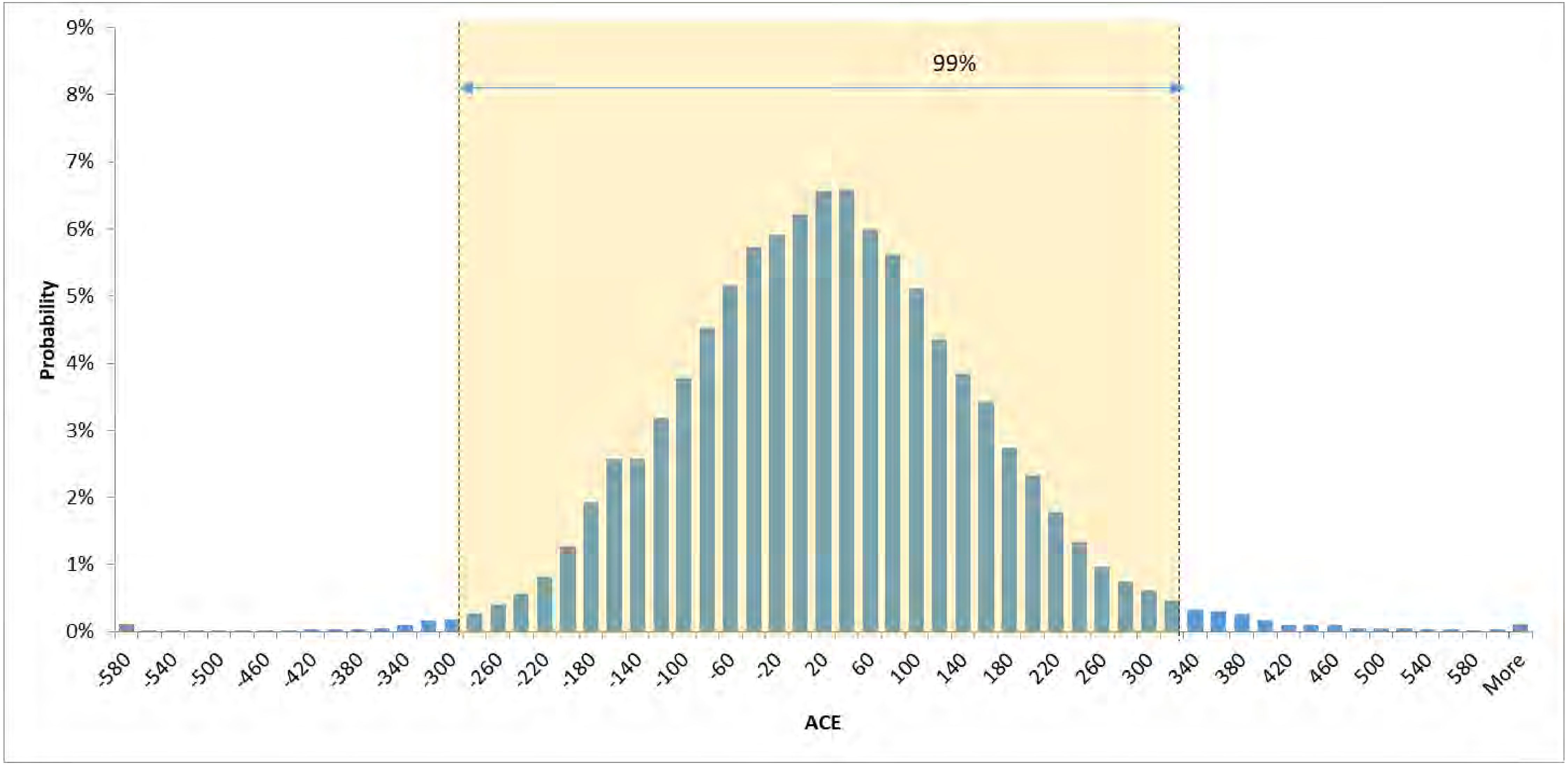
Estimation of Reserves (Tertiary)

- The estimated quantum of tertiary reserve requirement at regional level would be considered equal to the secondary reserve requirement at regional level

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

Example: Sample Area Control Error of Odisha

ACE Histogram of Odisha for 04th April to 10 April 2022



ACE = ((-2811) – (- 2547)) - 10 * (-150) * (50.07 – 50) = -159 (Sample Representation of ACE)

Estimation of Up Reserves : Sample Calculation of Odisha

S.No.	Steps	Computation
1	**Calculation of 99 Percentile of ACE**	Odisha Actual 99 Percentile Negative ACE (MW) = 271, Eastern Region Actual 99 Percentile Negative ACE (MW) = 948, ER state Sum of Actual 99 Percentile Negative ACE (MW) = 1235
2	**Scaling of ACE**	Odisha Scaled 99 Percentile Negative ACE (MW) = 208 { 271*(948/1235)}
3	**Inputs from States**	Odisha Max. Demand met = 5597 MW Internal generation at the time of Max. demand = 3260 MW. Drawl from ISTS = 2337 MW (5597-3260)
4	**Computation and apportionment of Secondary Reserves**	Odisha Secondary Reserves in ISGS = 87 MW {208 *(2337/5597)} Odisha Secondary Reserves within state = 121 MW {208*(3260/5597)}
5	**Computation and apportionment of Tertiary Reserves**	Odisha Tertiary Reserves in ISGS = 87 MW (equal to Odisha Secondary Reserves in ISGS) Odisha Tertiary Reserves within state = 421 MW {Odisha Secondary Reserves within state(121) + 50 % of largest unit size within state(300) }

Balancing Reserves Dimensioning

Ignoring Diversity Benefit

Type of Reserve	All India Total (MW)
Secondary	9161
Tertiary	14791
Total (MW)	23952

Type of Reserve	ODISHA (MW)
Secondary	281
Tertiary	581
Total (MW)	862

Reserve Requirement – Considering Diversity Benefit

Type of Reserve	Within State (MW)	ISGS (MW)	All India Total (MW)
Secondary	2607	2850	**5457**
Tertiary	8237	2850	**11087**
Total (MW)	10844	5700	**16544**

Type of Reserve	ODISHA within State (MW)	ODISHA in ISGS (MW)	Total (MW)
Secondary	73	136	**209**
Tertiary	73	436	**509**
Total (MW)	146	572	**718**

Reserve Requirement reduces by ~30% on all India basis with consideration of diversity benefits in estimation of reserves

Information Dissemination (1 of 4)

- The requirement of SRAS and TRAS reserves on year ahead, quarterly and week-ahead basis would be displayed and updated on the Nodal Agency website.
- The reference contingency shall be declared by Nodal Agency by 31st January before the start of each financial year (Format – RAS3).
  - The review of reference contingency may be done by the Nodal Agency, any time after the declaration, during the financial year.
  - Accordingly, the figures of reference contingency would be revised and updated on the Nodal Agency website.
  - *(Illustration: The reference contingency for financial year 2023-24 would be declared by 31st January, 2023)*

Information Dissemination (2 of 4)

- The assessment of the reserves capacity requirement for SRAS and TRAS on **Year Ahead Basis** would be declared by Nodal Agency by 25th January of the current year (Format – RAS4)
  - *(Illustration: The reserve requirement for SRAS and TRAS in financial year 2023-24 would be declared by 25th January, 2023)*

- The assessment of the reserves capacity requirement for SRAS and TRAS on **Quarterly Basis** would be declared by Nodal Agency by last day of the first month of the current quarter (Format – RAS5)
  - *(Illustration: The reserve requirement for SRAS and TRAS in quarter July – September, 2022 would be declared by 30th April, 2022)*

Information Dissemination (3 of 4)

- The assessment of the reserve capacity requirement for SRAS and TRAS for the succeeding week would be declared by Nodal Agency by Thursday of the preceding week (Format – RAS6)
  - (Illustration: The reserve requirement for SRAS and TRAS in Week-10 of FY 2022-23 would be declared by Thursday of Week–9 of FY 2022-23)

- The summary of reserve requirement on year-ahead, quarter-ahead and week-ahead would be published on Nodal Agency website (Format – RAS7).

Information Dissemination (4 of 4)

- The status of data received by the nodal agency from various sources and static data such as peak demand of the state, internal generation, frequency bias etc. shall also be published on the nodal agency website.

Thank You !

Format - RAS1 (SLDC to RLDC)

- Actual interchange of the State (10 seconds resolution), (Number of samples = 365*24*60*6 = 3153600 nos.) in excel format
- Frequency Response Characteristics of the State for the events posted on NLDC website (https://posoco.in/frc/)
- Peak Demand met
- Intra-State Generation (other than ISGS) at the time of peak demand
- In case of non-availability of data from SLDCs as mentioned above, the data available at RLDCs/Nodal Agency shall be used.

Actual Interchange of the State (10 seconds resolution) for calendar: 01.01.yyyy to 31.12.yyyy	
Date & Time (DD-MMM-YY HH:MM:SS)	Actual interchange of the State (MW)
01-Jan-2021 00:00:10	452
01-Jan-2021 00:00:20	456
01-Jan-2021 00:00:30	461
......	
......	
31-Dec-2021 23:59:50	498

Frequency Response Characteristics of the State for calendar: 01.01.yyyy to 31.12.yyyy	
Event Details	Frequency Response Characteristics (MW/Hz)
Events 1:	800
Event 2:	815
Event 3:	756

Peak Demand and Intra-State Generation of the State for calendar: 01.01.yyyy to 31.12.yyyy		
State/UT	Peak Demand met (MW)	Intra-State Generation (other than ISGS) at the time of peak demand (MW)
....		

Format – RAS2 (SLDC to RLDC)

- Actual interchange of the State (10 seconds resolution), (Number of samples = 120*24*60*6 = 1036800 nos.) in excel format
- Frequency Response Characteristics of the State for the events posted on NLDC website (https://posoco.in/frc/)
- Peak Demand met
- Intra-State Generation (other than ISGS) at the time of peak demand
- In case of non-availability of data from SLDCs as mentioned above, the data available at RLDCs/Nodal Agency shall be used.

Actual interchange of the State (10 seconds resolution) for the Quarter: 01.mm.yyyy to 31.mm.yyyy	
Date & Time (DD-MMM-YY HH:MM:SS)	Actual interchange of the State (MW)
01-Apr-2021 00:00:10	452
01-Apr-2021 00:00:20	456
01-Apr-2021 00:00:30	461
.....	
....	
31-June-2021 23:59:50	498

Frequency Response Characteristics of the State for the Quarter: 01.mm.yyyy to 31.mm.yyyy	
Event Details	Frequency Response Characteristics (MW/Hz)
Events 1:	800
Event 2:	815
Event 3:	756

Peak Demand and Intra-State Generation of the State for Quarter: 01.mm.yyyy to 31.mm.yyyy		
State/UT	Peak Demand met (MW)	Intra-State Generation (other than ISGS) at the time of peak demand (MW)
——		

Format – RAS3

Reference contingency for Indian Power System

Date: 31 January 2023	Revision No.	
Applicable for FY 2023-24		
Reference Contingency for generation loss (MW)	4500	
Reference Contingency for load loss (MW)	4500	

Format – RAS4

SRAS and TRAS Reserve requirement for year 2022-23

State/UT	Actual 99 Percentile Negative ACE (MW)	Actual 99 Percentile Positive ACE (MW)	Scaled 99 Percentile Negative ACE (MW) (a)	Scaled 99 Percentile Positive ACE (MW) (b)	Max. Demand met (c)	Internal Gen. at the time of max demand (d)	Drawl from ISTS (e=c-d)	State Internal Generation/ State Maximum Demand (f=d/c)	State drawl from ISTS/ State Maximum Demand (g=e/c)	Secondary Reserves in ISGS (h=a*g)	Secondary Reserves at Regional Level: (sum of reserves in all states of the region as given in "h")	Secondary Reserves within state (i=a*f)	Tertiary Reserves in ISGS (j = h)	Tertiary Reserves within state (k = i)	Largest Unit Size of internal generation (l)	Total Tertiary Reserves within state (m=k + 0.5*l)
West Bengal	319	336	237	201	9316	6800	2516	0.73	0.27	64	522	173	64	173	500	423
Bihar	364	381	270	228	6868	400	6468	0.06	0.94	255		16	255	16	250	141
Odisha	281	336	209	201	6008	3903	2105	0.65	0.35	73		136	73	136	600	436
Jharkhand	154	164	114	98	1718	394	1324	0.23	0.77	88		26	88	26	210	131
DVC	272	273	202	163	3487	5638	-2151	1.62	-0.62	0		327	0	327	600	627
Sikkim	57	48	42	29	132	0	132	0.00	1.00	42		0	42	0	0	0
ER state Sum	1447	1538	1075	921												1757
Eastern Region	1075	921														
Assam	111	111	73	87	2132	340	1792	0.16	0.84	60	154	11	60	11	50	36
Meghalaya	41	39	27	31	391	114	277	0.29	0.71	19		8	19	8	42	29
Tripura	59	60	38	47	327	172	155	0.53	0.47	18		20	18	20	21	31
Manipur	25	26	16	20	244	0	244	0.00	1.00	16		0	16	0	0	0
Mizoram	16	23	10	18	144	54	90	0.38	0.63	6		4	6	4	6	7
Nagaland	20	30	13	24	153	14	139	0.09	0.91	12		1	12	1	8	5
Arunachal Pradesh	34	42	22	33	162	0	162	0.00	1.00	22		0	22	0	0	0
NER State Sum	306	331	198	260												108
North-Eastern Region	198	260														
All India	5333	6096	5333	6096									2800			8237
										Total Tertiary Reserves Requirement in India			11037			

Format – RAS5

SRAS and TRAS Reserve requirement for Quarter 1 of year 2022-23																
State/UT	Actual 99 Percentile Negative ACE (MW)	Actual 99 Percentile Positive ACE (MW)	Scaled 99 Percentile Negative ACE (MW) (a)	Scaled 99 Percentile Positive ACE (MW) (b)	Max. Demand met (c)	Internal Gen. at the time of max demand (d)	Drawl from ISTS (e=c-d)	State Internal Generation/ State Maximum Demand (f=d/c)	State drawl from ISTS/ State Maximum Demand (g=e/c)	Secondary Reserves in ISGS (h=a*g)	Secondary Reserves at Regional Level (sum of reserves in all states of the region as given in "h")	Secondary Reserves within state (i=a*f)	Tertiary Reserves in ISGS (j = h)	Tertiary Reserves within state (k = i)	Largest Unit Size of internal generation (l)	Total Tertiary Reserves within state (m=k + 0.5*l)
West Bengal	365	423	326	221	9068	6569	2499	0.72	0.28	90	754	236	90	236	500	486
Bihar	426	472	380	246	6045	387	5658	0.06	0.94	356		24	356	24	250	149
Odisha	284	369	254	192	5771	3367	2404	0.58	0.42	106		148	106	148	600	448
Jharkhand	172	197	153	108	1636	217	1419	0.13	0.87	133		20	133	20	210	125
DVC	256	286	228	149	3421	5603	-2182	1.64	-0.64	0		374	0	374	600	674
Sikkim	56	60	50	31	96	0	96	0.00	1.00	50		0	50	0	0	0
ER state Sum	1554	1807	1391	943												1883
Eastern Region	1391	943														
Assam	127	122	104	96	1974	330	1644	0.17	0.83	87	227	17	87	17	50	42
Meghalaya	42	42	34	33	354	0	354	0.00	1.00	34		0	34	0	42	21
Tripura	78	60	64	47	336	176	160	0.52	0.48	31		34	31	34	21	44
Manipur	24	23	19	18	226	0	226	0.00	1.00	19		0	19	0	0	0
Mizoram	16	19	13	15	130	0	130	0.00	1.00	13		0	13	0	6	3
Nagaland	18	21	15	17	149	0	149	0.00	1.00	15		0	15	0	8	4
Arunachal Pradesh	35	51	28	40	145	0	145	0.00	1.00	28		0	28	0	0	0
NER State Sum	340	337	278	266												115
North-Eastern Region	278	266														
All India	6046	6977	6040	6977									2992			8830
Total Tertiary Reserves Requirement in India											11821					

Format – RAS6

Week-Ahead SRAS and TRAS Reserve requirement for Week 04 April to 10 April 2022													
State/UT	Scaled 99 Percentile Positive ACE (MW) (b)	Max. Demand met (c)	Internal Gen. at the time of max demand (d)	Drawl from ISTS (e=c-d)	State Internal Generation/ State Maximum Demand (f=d/c)	State drawl from ISTS/ State Maximum Demand (g=e/c)	Secondary Reserves in ISGS (h=a*g)	Secondary Reserves at Regional Level (sum of reserves in all states of the region as given in "h")	Secondary Reserves within state (i=a*f)	Tertiary Reserves in ISGS (j = h)	Tertiary Reserves within state (k = i)	Largest Unit Size of internal generation (l)	Total Tertiary Reserves within state (m=k + 0.5*l)
West Bengal	280	8586	6775	1811	0.79	0.21	44	447	165	44	165	500	415
Bihar	252	5769	319	5450	0.06	0.94	206		12	206	12	250	137
Odisha	284	5597	3260	2337	0.58	0.42	87		121	87	121	600	421
Jharkhand	114	1583	409	1174	0.26	0.74	90		31	90	31	210	136
DVC	204	3563	5295	-1732	1.49	-0.49	0		255	0	255	600	555
Sikkim	40	120	0	120	0.00	1.00	20		0	20	0	0	0
ER state Sum	1175												1665
Eastern Region													
Assam	102	1847	213	1634	0.12	0.88	56	147	7	56	7	50	32
Meghalaya	34	372	86	286	0.23	0.77	21		6	21	6	42	27
Tripura	54	292	150	142	0.51	0.49	18		19	18	19	21	30
Manipur	25	225	0	225	0.00	1.00	13		0	13	0	0	0
Mizoram	21	124	0	124	0.00	1.00	9		0	9	0	6	3
Nagaland	22	164	0	164	0.00	1.00	11		0	11	0	8	4
Arunachal Pradesh	51	192	0	192	0.00	1.00	19		0	19	0	0	0
NER State Sum	309												97
North-Eastern Region													
All India	5722									2969			8271
Total Tertiary Reserves Requirement in India								11240					

Format – RAS7

	Year-Ahead						Quarter-Ahead						Week-Ahead					
	Secondary Reserves			Tertiary Reserves			Secondary Reserves			Tertiary Reserves			Secondary Reserves			Tertiary Reserves		
State/UT	Within in ISGS	Within state	Total	Within in ISGS	Within state	Total	Within in ISGS	Within state	Total	Within in ISGS	Within state	Total	Within in ISGS	Within state	Total	Within in ISGS	Within state	Total
West Bengal	64	173	237	64	423	487	90	236	326	90	486	576	44	165	209	44	415	459
Bihar	255	16	270	255	141	395	356	24	380	356	149	505	206	12	219	206	137	344
Odisha	73	136	209	73	436	509	106	148	254	106	448	554	87	121	208	87	421	508
Jharkhand	88	26	114	88	131	219	133	20	153	133	125	258	90	31	121	90	136	226
DVC	0	327	327	0	627	627	0	374	374	0	674	674	0	255	255	0	555	555
Sikkim	42	0	42	42	0	42	50	0	50	50	0	50	20	0	20	20	0	20
Assam	60	11	72	60	36	97	87	17	104	87	42	129	56	7	64	56	32	89
Meghalaya	19	8	27	19	29	48	34	0	34	34	21	55	21	6	27	21	27	48
Tripura	18	20	38	18	31	49	31	34	64	31	44	75	18	19	38	18	30	48
Manipur	16	0	16	16	0	16	19	0	19	19	0	19	13	0	13	13	0	13
Mizoram	6	4	10	6	7	13	13	0	13	13	3	16	9	0	9	9	3	12
Nagaland	12	1	13	12	5	17	15	0	15	15	4	19	11	0	11	11	4	15
Arunachal Pradesh	22	0	22	22	0	22	28	0	28	28	0	28	19	0	19	19	0	19
	Region-wise and All-India																	
Northern Region	725	480	1205	725	2091	2816	406	433	838	406	2044	2449	591	361	952	591	1972	2563
Western Region	829	769	1598	829	2079	2908	853	1181	2034	853	2491	3344	791	703	1494	791	2013	2804
Southern Region	620	637	1257	620	2202	2822	771	733	1504	771	2298	3069	993	960	1953	993	2525	3518
Eastern Region	522	677	1200	522	1757	2280	734	803	1537	734	1883	2617	447	585	1032	447	1665	2112
North-Eastern Region	154	44	198	154	108	262	227	51	278	227	115	342	147	33	180	147	97	243
All India	2850	2607	5458	2850	8237	11087	2992	3200	6192	2992	8830	11821	2969	2642	5611	2969	8271	11240

Annexure-C18.2

CENTRAL ELECTRICITY REGULATORY COMMISSION (CONNECTIVITY AND GENERAL NETWORK ACCESS TO THE INTER-STATE TRANSMISSION SYSTEM) REGULATIONS, 2022

Transmission Access- Prevailing regime

- Transmission system booking
  - Long term Access (LTA)- 7 years and above
  - Medium term Open Access (MTOA)– 3 months to 5 years
  - Short term Open Access (STOA) - 1 time block to 1 month (up to 3 months in advance)
  - Each Access comprise of booking of system from injection point till drawl point

- Availing of the booked transmission system by scheduling
  - Scheduling of power is under contract between buyer and seller
  - LTA – PPA for duration more than one year
  - MTOA and STOA- PPA for the duration of Access to be furnished along with the application

Need for change:

- Realities of procurement of cheaper power
- Requirement of delinking of access to transmission system with fixed contract.
- Schedules under STOA cannot change 2 days hence.
  -Need to review inflexibility raised by stakeholders.
- Streamline relinquishment charges.

Background

- Draft GNA Regulations were notified on 14.11.2017.
- Subsequently few developments have taken place:
  - Requirements of new provisions for connectivity to projects based on renewable sources to inter-State Transmission System.
    - Detailed Procedure – May’ 2018, Feb’ 2021, 7th Amendment to the 2009 Connectivity Regulations.
  - Upcoming changes in sector

- Draft GNA Regulations 2021- notiifed on 16.12.2021
- Final GNA Regulations notified on 7.6.2022

- GNA Regulations 2022 consists of broadly three sections:

  (A) Connectivity

  (B) General Network Access (GNA)

  (C) Temporary GNA (T-GNA)

Connectivity

- **Application fees : Rs 5 lakh + taxes / application**
- **Eligible Entities:**
  - Injecting entities who are seeking connectivity to the ISTS
  - Connectivity grantees shall be deemed to have been granted GNA, equal to the quantum of Connectivity from the start date of Connectivity.
  - Minimum quantum to connect to ISTS- Installed capacity of 50 MW individually or collectively through lead generator.

Additional points

- Entities having Connectivity may apply for enhancement of Connectivity of less than 50 MW subject to available capacity in transmission system.
- At a terminal bay already allocated to another Connectivity grantee with an agreement for sharing the terminal bay.
- Through electrical system of a generating station having Connectivity to ISTS with an agreement for sharing.
- Two or more Applicants may apply for grant of Connectivity at a common terminal bay with an agreement for sharing the dedicated transmission lines and the terminal bay.

Connectivity…contd.

- Eligible entities shall seek Connectivity equal to Installed Capacity (IC) subject to following:

Sr. No.	Applicant	Connectivity Quantum
1	Generating Stations including REGS	Equal to Installed Capacity
2	Renewable Hybrid Generating Station or REGS with storage	Less than or equal to the installed capacity
3	Captive generating plant	Maximum injection to ISTS
4	Standalone ESS (energy storage system)	Maximum injection to ISTS or proposed maximum drawal from ISTS, whichever is higher
5	Renewable Power Park Developer	Quantum for which it has been authorised by the Central Government or a State Government

- Dual Connectivity: Generating station may be connected to both intra-State transmission system and inter-State transmission system.
  - A generating station, already connected to or intending to connect to intra-State transmission system shall also be eligible for Connectivity to ISTS for a quantum not exceeding the balance of the installed capacity

Grant of Connectivity

- In-principle grant of Connectivity
  - Preliminary intimation seeking to submit Connectivity Bank Guarantees.

    - within 30/60 days (where ATS is required)

- Final Grant of Connectivity
  - On submission of required Connectivity Bank Guarantees

- Grant of Connectivity may have following situations
  - Neither the ISTS bay at which Connectivity is proposed is to be constructed under ISTS, nor any augmentation is required to ISTS-
  - Only terminal ISTS bay is constructed under ISTS or to be constructed under ISTS. No further augmentation of ISTS required
  - Augmentation of ISTS is required along with terminal bay or without terminal bay.

Connectivity Bank Guarantee (Conn-BGs): SHORT IT

- Three parts:
- Conn-BG1 amounting to Rs. 50 lakhs for all applicants.
- Conn-BG2: Towards Terminal Bay as follows (where no ATS)

Voltage level of allocated terminal bay	Conn-BG2 (per terminal bay)
132 kV	Rs. 2 crore
220/230 kV	Rs. 3 crore
400 kV	Rs. 6 crore
765 kV	Rs. 12 crore

- Conn-BG2: Not applicable In case entity (i) proposes to construct the terminal bay(s) on its own or (ii) seeks Connectivity at a terminal bay constructed or being constructed by another Connectivity grantee or (iii) seeks Connectivity through electrical system or switchyard of a generating station
- Conn-BG3: Applicable if Connectivity granted on existing system @ Rs 2 lakhs/MW

Connectivity Bank Guarantee (Conn-BGs)…Contd.

- In case augmentation to ISTS is required to grant Connectivity:
  - Conn-BG2 shall be as per the estimated cost of such Associated Transmission System and terminal bay(s).
  - Nodal Agency within 6 (six) months of furnishing of Conn-BG1 shall intimate

    (i) amount of Conn-BG2 to be furnished towards ATS and terminal bay(s), which shall not exceed the estimated cost intimated

    (ii) the timeline for completion of ATS and terminal bay(s), and

    (iii) firm date of start of Connectivity
- In the event of non-intimation by Nodal Agency within six months, the entity shall have the option of withdrawing the application for Connectivity and in such a case, the Conn-BG1 shall be returned.

Treatment of Conn-BGs:

- Conn-BG1 i.e. Rs 50/Lakh shall be returned within 30 days of COD of full capacity.
  - In case part capacity is relinquished say 200 MW out of 500 MW is relinquished then Conn-BG1 shall be returned after COD of 300 MW.
- Conn-BG2 and Conn-BG3 shall be returned in five equal parts over five years corresponding to the generation capacity which has been declared under commercial operation.
- In case Connectivity is relinquished, subsisting Conn-BG2 shall be encashed corresponding to the ATS and terminal bay(s), construction of which has already been awarded for implementation.
- The proceeds of encashed Conn-BG2 shall be used for reducing Monthly Transmission Charges under the Sharing Regulations

General Network Access (GNA)

- Under the 2009 Connectivity Regulations
  - LTA or MTOA granted to an entity is a right granted to such an entity for transfer of electricity from a specified injection point to a specified drawal point on ISTS.

- Under the Draft GNA Regulations,
  - all grid connected entities i.e. a selling entity or a buying entity shall have GNA.
  - GNA of injecting entities shall be equal to its Connectivity.
  - Buying entities shall seek GNA as per their requirements.
  - Such GNA is not from identified injection point to identified drawal point, rather it is an open access which shall provide flexibility in terms of injection point for a buying entity under different types of contracts.
  - Similarly selling entity has flexibility to sell any buying entity under different types of contracts.

Eligibility for GNA

- State Transmission Utility on behalf of distribution licensees connected to intra-State transmission system and other intra-State entities. No financial liability on STUs.
- A buying entity connected to intra-State transmission system
- A distribution licensee or a Bulk consumer, seeking to connect to ISTS, directly, (50 MW & above)
- Trading licensees (engaged in cross border trade) for drawal and injection into the Grid
- Transmission licensee connected to ISTS for drawal of auxiliary power.

GNA for States:

- Each State shall have a General Network Access (GNA) to ISTS.
- To start with GNA for States shall be specified based on ISTS drawal for last 3 years.
- States shall be able to schedule power under long term or medium term or short term contracts based on its own assessment of merit order on day ahead basis within GNA quantum. This flexibility will help them optimise their overall procurement cost.
- Additional GNA may be sought by State as per their requirement.
- States shall pay transmission charges for GNA quantum in accordance with CERC(Sharing of inter-state transmission charges and losses) Regulations 2020.
- Any drawal beyond GNA shall be with additional charges.
- GNA once granted shall remain valid until relinquished.
- GNA granted to a State may be utilized by another State.
- GNA can be applied for by
  - STU on behalf of intra-state entities or
  - intra-state entity

Grant of GNA

- For the first year GNA for states shall be considered based on historical data of last 3 years for yearly maximum ISTS drawl and daily maximum ISTS drawal.

- GNA shall be the average of 'A' for the financial years 2018-19, 2019-20 and 2020-21:

where,

  - 'A' = {0.5 X maximum ISTS drawal in a time block during the year} + {0.5 X [average of (maximum ISTS drawal in a time block in a day) during the year]}

- STU shall be the entity to whom GNA shall be deemed to be granted as per above on behalf of intra state entities. Transmission charges liability shall be with intra-state entities as per prevailing regime.
- STUs within 3 months of coming into force of these regulations, on behalf of intra-state entities, may apply for additional GNA over and above the GNA deemed
- States may apply for additional GNA to be added in next 3 years, every year in September.

National Load Despatch Centre
Total Transfer Capability for April 2022

Issue Date: 28th December, 2021 | Issue Time: 1700 hrs | Revision No

Corridor	Date	Time Period (hrs)	Total Transfer Capability (TTC)	Reliability Margin	Available Transfer Capability (ATC)	Long Term Access (LTA)/ Medium Term Open Access (MTOA) #	Margin Available for Short Term Open Access (STOA)	Changes in TTC w.r.t. Last Revision
NR-WR*	1st April 2022 to 30th April 2022	00-06	2500	500	2000	628	1372	
		06-18				1856	144	
		18-24				628	1372	
WR-NR*	1st April 2022 to 30th April 2022	00-06	19500 18550**	1000	18500 17550**	11433 10483**	7067	
		06-18	19500 18550**	1000	18500 17550**	11822 10872*	6678	
		18-24	19500 18550**	1000	18500 17550**	11433 10483**	7067	
NR-ER*	1st April 2022 to 30th April 2022	00-06	2000	200	1800	93	1707	
		06-18	2000		1800	1308	492	
		18-24	2000		1800	93	1707	
ER-NR*	1st April 2022 to 30th April 2022	00-24	5900	400	5500	4356	1144	

Concept of 'within region' and 'outside region'.

Contracts in each region- for a sample month

	ER	NER	NR	SR	WR	Grand Total
Himachal Pradesh	22	0	1728	0	0	1750
Uttarakhand	26	0	1078	0	93	1197
J&K	137	0	2056	0	93	2286
Delhi	1042	0	3766	0	419	5226
Rajasthan	243	0	2711	0	1258	4212
Haryana	413	150	2764	0	1084	4410
Uttar Pradesh	625	54	8130	0	2243	11052
Punjab	869	0	2386	0	1033	4288
Chandigarh	3	0	331	0	0	334
			24950		6223	34756

Grant of GNA…contd.

- GNA deemed to have been granted to STU shall be segregated as (i) GNA within the region and (ii) GNA from outside the region, in proportion to contracts, within the region or outside the region, under Long Term Access and Medium Term Open Access obtained in terms of the Connectivity Regulations.

- Transmission charges are paid by the intra-State entities in the State and, hence, there is a need to segregate GNA quantum for all intra-State entities. Since SLDC of the State has information related to drawal of each intra-State entity, it is proposed that SLDC shall carry out such segregation of GNA quantum of the State into various intra-State entities and intimate the same to STU, CTU and NLDC.

- In case an intra-State entity including a distribution licensee having GNA covered under clause (i) of Regulation 17.1, substitutes GNA with GNA under clause (ii) of Regulation 17.1, GNA for such intra-State entity shall be reduced from the total GNA of STU as held under clause (c) of Regulation 22.1, for the quantum so substituted and for such substituted period.

Grant of additional GNA to STUs

- Deemed GNA computed for a STU 'A' is 4000 MW.
- 'A' applies for additional GNA for 800 MW within next 3 months which is granted to 'A' by CTU,
  - GNA for 'A' will become 4800 MW (4000 MW + 800 MW).
- 'A' may apply once in every financial year by the month of September for additional GNA for the next 3 financial years indicating the start date for such quantum.

Financial Year	Additional GNA granted in each FY from a specified date	Total GNA after grant of additional GNA
2023-24	200 MW w.e.f. 22.6.2023	5000 MW w.e.f. 22.6.2023
2024-25	100 MW w.e.f. 18.5.2024	5100 MW w.e.f. 18.5.2024
2025-26	300 MW w.e.f. 14.9.2025	5400 MW w.e.f. 14.9.2025

GNA for Trading Licensee…contd.

- where

-G1 is a generating station located in other Country

-A is the border substation at which GNA is sought for purpose of injection into Indian grid

-B is the border substation at which GNA is sought for purpose of drawal from Indian grid

-B-1 is buying entity located in other Country.

Use of GNA by another GNA grantee

- Any entity having surplus GNA for a period due to reduction in load or seasonal variation, can authorize part of its granted GNA to others with prior approval of CTU. (for period not exceeding 1 year and on mutually agreed terms)

- Liability to pay GNA charges shall be with original GNA grantee

- For example, Punjab may buy GNA capacity for a specific quantum from Delhi/Haryana in case there is diversity in their ISTS drawal requirement and optimise their transmission charges.

- Suppose UP has 10000 MW GNA and in a season, it may not need to draw for 800 MW from ISTS. Punjab may have ISTS drawal requirement additional to its GNA of 8000 MW in that season. Punjab can use GNA of UP as per mutually agreed terms.

- Subject to availability of drawal capacity of the State.

- For the purpose of calculation of transmission deviation charges, GNA of Uttar Pradesh and Punjab shall be considered as 9,200 MW and 8,800 MW respectively for that period.

Temporary GNA (T-GNA)

- Product akin to prevailing STOA.
- Can be availed over and above GNA.
- 1 time block to 11 months.
- Scheduling flexibility on day ahead basis.
- Priority to get corridor allocation after GNA grantees.
- Payment of transmission charges 1 month in advance.

T-GNA

- Applicants- buyers
  - Distribution licensee /bulk consumer/captive generating plant / ESS / generating station for auxiliary/startup
  - Trading license on behalf of buyers
  - Power exchanges

- Application fees- Rs 5000/application
- Bilateral transactions
  - Advance application for grant of T-GNA: For T-GNA starting on or after the (D+3) day- same month or next month starting
  - Exigency application for grant of T-GNA: Application made on (D) day for grant of T-GNA with scheduling for (S) day, which may be (D) day or (D+1) day or (D+2) day, with a minimum start time of 7 (seven) time blocks unless specified otherwise in the Grid Code:
    - Maximum for 1 day

Advance application category:

- Quantum of T-GNA in MW;
- Start time of T-GNA in terms of time-block and date;
- End time of T-GNA in terms of time-block and date;
- Point of injection, if available, or in the absence of the point of injection, the target injection region;

Provided that in case of injection into the Indian grid in the course of cross border trade of electricity in terms of the Cross Border Regulations, point of injection shall be furnished along with the application.

- Point of drawal;
- Standing Clearance of SLDC under whose jurisdiction the point of drawal is located, in case the buyer is an intra-State entity and;
- In case the seller is an intra-State entity and the point of injection is available, Standing Clearance of SLDC under whose jurisdiction the point of injection is located:

Provided that in case the point of injection and corresponding Standing Clearance of SLDC under whose jurisdiction the point of injection is located is not available at the time of making the application, the same shall be submitted along with the scheduling request in terms of Regulation 33 of these regulations;

- In case the seller is a regional entity and the point of injection is not available at the time of making the application, the point of injection shall be submitted along with the scheduling request in terms of Regulation 33 of these regulations.

Exigency application category:

- Contracted quantum of power (MW) to be scheduled at point of injection;
- Start time of T-GNA in terms of time-block and date;
- End time of T-GNA in terms of time-block and date;
- Point of injection;
- Point of drawal;
- Standing Clearance of SLDCs under whose jurisdiction the point of drawal and point of injection are located, in case the buyer or the supplier is an intra-State entity, as applicable.
- Copy of contract

Declarations at time of Advance application

- That necessary infrastructure for time-block wise metering and accounting and appropriate communication system are in place for the point of drawal and point of injection, if available.

- If the point of injection has not been identified, abovesaid availability of necessary infrastructure for time-block wise metering and accounting and communication system for the point of injection and, the Standing Clearance of SLDC, in case the seller is an intra-State entity, under whose jurisdiction such point of injection is located, shall be submitted along with the scheduling request.

- Applicant indemnifies the Nodal Agency at all times from any and all claims, actions and all other obligations by or to third parties arising out of or resulting from the transactions under T-GNA.

- That there is a valid contract for the proposed scheduling:
  - Same may be provided at time of scheduling request

Processing of applications for T-GNA

- Advance applications - on first-come-first-served basis - processed latest by 23.59 hrs of the (D+1) day, 'D' being the date of making the application.

- Exigency applications for T-GNA with the schedule for (S) day shall be processed as under:
  - Applications received till 1300 hrs of (S-1) day shall be processed after 1300 hrs on (S-1) day on first-come-first-served basis, and shall be finalised by 1400 hrs of (S-1) day.
  - Applications received after 1300 hrs of (S-1) day or in the (S) day shall be processed within 4 time blocks, on first-come-first-served basis.

- T-GNA for collective transactions under day ahead market shall be processed by 1300 hrs of (S-1) day.

- T-GNA for collective transactions under real time market shall be processed within a time block.

Revision of T-GNA

- T-GNA granted under Exigency application category or under Advance application category for a period not exceeding one month cannot be revised.

- T-GNA granted under Advance application category for a period of more than one month may be reduced for the balance period with a prior notice of one (1) month by the T-GNA grantee:

- Provided that applicable T-GNA charges for the quantum of T-GNA granted shall be payable for the notice period of one (1) month.

Scheduling request for power under T-GNA

- Advance application category:

Scheduling request by T-GNA grantees under Advance application category shall be made on day ahead basis before the opening of bidding window for collective transactions under day ahead market, as per provisions of the Grid Code.

- T-GNA granted under Exigency application category shall be considered as schedule, which cannot be revised.

Transmission charges for T-GNA

- Transmission charge rate for T-GNA, in Rs./MW/time block, for a State shall be published for each month by the Implementing Agency in terms of the Sharing Regulations.

- Transmission charges for T-GNA, in case of bilateral and collective transactions, shall be payable only at point of drawal, as per the last published Transmission charge rate for T-GNA for the State where such point of drawal is located:

- Under collective transactions, transmission charges for T-GNA shall be payable for drawal schedules more than GNA quantum or T-GNA quantum or both, as applicable.

- In case any scheduling request under T-GNA is not approved by RLDC on day ahead basis or curtailed for the reasons of transmission constraints or grid security, the transmission charges for such quantum not scheduled or curtailed shall be refunded to the T-GNA grantee.

Transmission charges-T-GNA

- For T-GNA up to one (1) month - within three (3) working days of grant of T-GNA:

  Provided that where T-GNA is starting within next 3 working days, transmission charges for T-GNA shall be deposited before the start date of T-GNA;

- For T-GNA for more than 1 month - charges for the first month, within three (3) working days of grant of T-GNA but before the start date of T-GNA and charges for each subsequent month including part thereof, if any, on rolling basis, one month in advance.

Allocation of Transmission Corridor

- State having GNA, can request scheduling from injection point of its choice as per its contract. The methodology of scheduling and priority of transmission corridor allocation shall be covered under the Grid Code.

- In case the scheduling request of the GNA Grantee cannot be accommodated by RLDC due to constrain in transmission corridor, RLDC shall allocate the available transmission corridor amongst the GNA grantees in proportion to their GNA within the region or from outside region and the GNA grantee shall be eligible to schedule power under any contract within such allocated transmission corridor. In case the revised schedule is not furnished by the GNA Grantee, RLDC shall finalise the schedule for such GNA Grantee by pro rata reduction of schedule under each contract for such constrained transmission corridor.

- Transmission corridor shall be allocated on day ahead basis to GNA grantees and TGNA grantees as per the priority and indicative time-line as indicated in following illustration:

Allocation of Transmission Corridor…contd.

Sr. No.	Activity	Time (By hours in S-1)*
1.	Generating stations to declare DC for "S day"	'T' hours
2.	RLDC to reflect respective share for each beneficiary	'T+1' hours
3.	GNA grantee to give scheduling request within GNA T-GNA grantee to give scheduling request within T-GNA	'T+2' hours
4.	In case demand of corridors is more than availability, RLDC to intimate pro-rata corridor allocation to GNA grantee to enable it to place revised scheduling request	T+2.5 hours
5.	RLDC to confirm schedules for GNA grantees	T+3 hours
6.	RLDC to release balance corridor for scheduling T-GNA requests under Advance Application	T+3 hours
7.	RLDC to process T-GNA scheduling request and confirm schedule for T-GNA grantees	T+3.5 hours
8.	RLDC to release balance corridor for day ahead collective transactions	T+3.5 hours

Allocation of Transmission Corridor…contd.

9.	Bidding window for Day ahead collective transactions	T+4 - T+5.5 hours
10.	Application by Power Exchange(s) for allocation of corridors	T+6 hours
11.	RLDC to confirm scheduling based on corridor availability	T+6.5 hours
12.	RLDC to issue schedule for collective transactions based on final market clearing by exchanges	T+7 hours
13.	RLDC to release balance corridor for Exigency applications received till T+7 hours	T+7 hours
14.	RLDC to process Exigency applications received till T+7 hours	T+8 hours
15.	RLDC to release balance corridor for schedule revision by GNA grantees, Exigency Applications, RTM	T+8 hours

*Indicative timeline to be finalised as per Grid Code

Transition mechanism

- Connectivity, LTA, MTOA
  - Applications yet to be granted, can be withdrawn or converted into applications as made under these Regulations

- LTA granted to a generating station or its identified buyer shall be considered as GNA for the generating station.

- For the Connectivity quantum without any LTA , GNA may be applied by the generating station with submission of Bank Guarantees as per these regulations.

- MTOA of 600 MW is granted for 3 Years but is not yet effective: 600 MW MTOA is deemed converted to GNA for 3 years with start date as the date from which such MTOA was to become effective.

Curtailment

- For the reason of transmission constraints or in the interest of grid security, transactions already scheduled may be curtailed:
  - Transactions under T-GNA shall be curtailed first followed by transactions under GNA.
  - Within transactions under T-GNA, bilateral transactions shall be curtailed first followed by collective transactions under day ahead market followed by collective transactions under real time market.
  - Within bilateral transactions under T-GNA, curtailment shall be on pro rata basis based on T-GNA.
  - Within transactions under GNA, curtailment shall be on pro rata basis based on GNA.

Relinquishment of GNA

- STU may relinquish GNA on behalf of identified Intra-state entity and the concerned Intra-State entity shall pay relinquishment charges that shall be equal to 24 times the transmission charges paid by such intra-State entity for the last billing month, corresponding to the relinquished quantum.

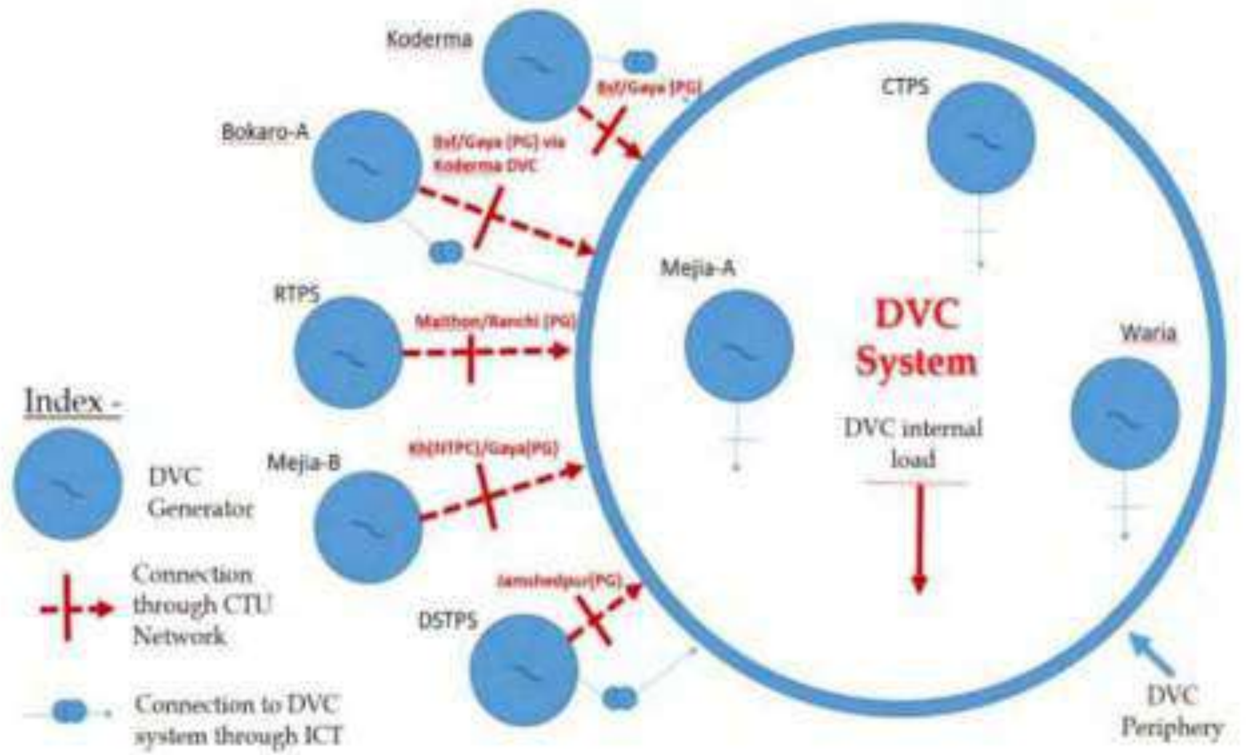
- Intra-State entities granted GNA under the 2021 Draft GNA Regulations may relinquish full or part GNA and shall pay relinquishment charges corresponding to the relinquished quantum for 24 months or balance period of the GNA whichever is lower.

THANK YOU

GNA for DVC:

- DVC is a deemed licensee as per 4th proviso of Section 14 of the Electricity Act, 2003. DVC is separate control area and is treated akin to a State. It has allocation of power from a few generating stations and it also owns a few generating stations.
- DSM is calculated separately for DVC as a State.
- RTA: LTA/ demand for DVC is taken as 622.19 MW, out of which 339.69 MW is for DVC, 200 MW is for Tata Steel Ltd. and 82.5 MW is for Railways DVC (embedded within DVC control area).
- RTDA: Transmission deviation charges for DVC area are also calculated separately as DVC State.
- In ISTS drawal data for DVC control area it was observed that DVC has a negative drawal schedule for every time block. The schematic diagram is as follows:

GNA for DVC…contd.



- DVC owns a few generating stations out of which Mejia Thermal Power Station #7 & #8, Durgapur Steel Thermal Power Station #1 & #2, Koderma Thermal Power Station #1 & #2, Bokaro Thermal Power Station-A #1, Raghunathpur Thermal Power Station #1 & #2 which are connected to ISTS.

GNA for DVC…contd.

- DVC as a control area have been considering injection for the above said identified generating stations as its embedded generating stations, but the transmission lines connecting such stations to DVC owned system is not within DVC control area. This needs to be considered while considering actual ISTS drawal for DVC.
- DVC as a State control area shall be granted deemed GNA
- ISTS drawl shall be has been considered after excluding injection from those generating stations that are connected to ISTS.
- These stations shall be treated like any other ISGS (inter-State generating station) which shall need to have a GNA at its injection point for its power to get scheduled.

GNA for BARC, HVDC Entities, Haryana & Essar Steel :

- BARC is also connected to ISTS and is a regional entity. From RTA and RTDA it is observed that LTA of 9.10 MW is considered for BARC.
- DSM charges in terms of the DSM Regulations are calculated for HVDCs as drawing entities. As per RTAs LTA/MTOA in respect of HVDCs is considered.
- M/s Adani Power (Mundra) Limited shall hold GNA for 1495 MW at Haryana periphery and Haryana would be able to schedule power from M/s Adani Power (Mundra) Limited under the said GNA of 1495 MW held by M/s Adani Power (Mundra) Limited. However, flexibility of scheduling from other injecting entities shall be available to Haryana only to the extent of GNA held by Haryana i.e. 5418 MW.
- DSM account for Essar Steel is prepared separately as AMNSIL (ESIL) as a buying entity of WR. Further, RTDA transmission deviation charges are also levied on AMNSIL (ESIL). Since Essar Steel is having ISTS drawal and is a Bulk consumer and a regional entity having Connectivity to ISTS, it is proposed that Essar Steel shall be granted deemed GNA.

Payment of Charges:

- Regulation 40 of the GNA Regulations provides:
- Transmission charges and losses for use of the inter-State transmission system shall be shared among drawee DICs of ISTS in accordance with the Sharing Regulations.
- One time GNA charges shall be payable by entities covered under Regulation 4.1 and clause (iii) of Regulation 17.1 of these regulations in terms of clause (d) of Regulation 22.2 of these regulations.

Payment of charges

- The transmission charges and losses for use of the inter-State transmission system shall be shared among buying entities of ISTS in accordance with the Sharing Regulations.

- One time GNA charges shall be payable by entities covered under Regulation 4.1 and clause (iii) of Regulation 17.1 of these regulations in terms of clause (d) of Regulation 22.2 of these regulations.

- The fees and charges for National Load Despatch Centre, Regional Load Despatch Centres (including the charges for Unified Load Despatch Scheme) and State Load Despatch Centres shall be payable by the GNA grantees as per the applicable Regulations.

- Deviation charges shall be applicable as per the DSM Regulations.

State	Yearly Average of Daily Max ISTS drawal (X_1) (MW)	Yearly Max ISTS drawal (Y_1) (MW)	A_1= 0.5* X_1 + 0.5* Y_1 (MW)	Yearly Average of Daily Max ISTS drawal (X_2) (MW)	Yearly Max ISTS drawal (Y_2) (MW)	A2 = 0.5* X2 + 0.5* Y2 (MW)	Yearly Average of Daily Max ISTS drawal (X_3) (MW)	Yearly Max ISTS drawal (Y_3) (MW)	A_3= 0.5* X_3 + 0.5* Y_3 (MW)	GNA (MW)= Average of A_1 A_2 & A_3
	2018-19			2019-20			2020-21			
Northern Region										
Chandigarh	262	474	368	267	431	349	233	383	308	342
Delhi	3735	5626	4681	3954	6257	5105	3642	5646	4644	4810
Haryana	5004	7739	6371	5728	8117	6922	5756	9132	7444	6913→ 5418**
HP	793	1421	1107	743	1398	1071	751	1675	1213	1130
J&K	1605	2210	1907	1570	2305	1937	1728	2444	2086	1977
Punjab	3556	6608	5082	4198	6681	5440	4823	7119	5971	5497
Rajasthan	3946	5668	4807	4429	7834	6131	5144	7512	6328	5755
UP	7343	10648	8996	8551	12500	10525	8999	12952	10975	10165
Uttarakhand	1154	1654	1404	1016	1761	1389	1117	1709	1413	1402
Western Region										
Chhattisgarh	1320	2492	1906	1743	2626	2184	1716	3001	2358	2149
Dadra Nagar Haveli	757	825	791	776	839	807	664	894	779	792
Daman Diu	320	355	337	317	363	340	278	367	323	334
Goa	476	598	537	518	639	578	459	596	527	548
Gujarat	5491	8852	7172	4373	6547	5460	4731	8611	6671	6434
Madhya Pradesh	5363	8268	6815	5611	8521	7066	6639	9764	8202	7361
Maharashtra	6804	10488	8646	6751	9053	7902	7535	10344	8940	8496
Southern Region										
Andhra Pradesh	2994	5015	4004	3094	5791	4443	4095	6110	5102	4516
Karnataka	3225	5026	4125	3232	4805	4019	3658	6312	4985	4376
Kerala	2269	2913	2591	2548	3034	2791	2365	2946	2655	2679
Pondicherry	359	413	386	376	464	420	352	427	390	398
Tamil Nadu	6962	9732	8347	7673	10496	9085	7973	12227	10100	9177
Telangana	4511	6515	5513	4453	8145	6299	4720	8494	6607	6140

State	Yearly Average of Daily Max ISTS drawal (X_1) (MW)	Yearly Max ISTS drawal (Y_1) (MW)	A_1= 0.5* X_1 + 0.5* Y_1 (MW)	Yearly Average of Daily Max ISTS drawal (X_2) (MW)	Yearly Max ISTS drawal (Y_2) (MW)	A2 = 0.5* X2 + 0.5* Y2 (MW)	Yearly Average of Daily Max ISTS drawal (X_3) (MW)	Yearly Max ISTS drawal (Y_3) (MW)	A_3= 0.5* X_3 + 0.5* Y_3 (MW)	GNA (MW)= Average of A_1 A_2 & A_3
Bihar	4291	5036	4664	4520	5664	5092	4773	5973	5373	5043
DVC*	687	996	841	829	1,158	993	881	1,187	1,034	956
Jharkhand	919	1167	1043	927	1270	1099	1050	1325	1188	1110
Odisha	1909	3080	2494	1300	3166	2233	825	2661	1743	2157
Sikkim	88	111	99	92	132	112	92	149	121	111
West Bengal	2549	6710	4629	2719	5334	4026	2091	4274	3183	3946
North Eastern Region										
Arunachal Pradesh	135	155	145	119	155	137	107	134	120	134
Assam	1273	1583	1428	1304	1737	1520	1391	1885	1638	1529
Manipur	174	211	193	179	216	198	196	246	221	204
Meghalaya	167	319	243	170	327	248	147	298	223	238
Mizoram	72	115	93	77	110	93	79	119	99	95
Nagaland	118	153	135	124	144	134	119	149	134	134
Tripura	225	366	295	222	380	301	261	414	337	311

Relinquishment of Connectivity

- In case of relinquishment of full quantum of Connectivity, subsisting Conn-BG1 shall be encashed and subsisting Conn-BG2 shall be encashed corresponding to the ATS and terminal bay(s), construction of which has already been awarded for implementation.

- In case of relinquishment of part quantum of Connectivity, subsisting Conn-BG2 shall be encashed in proportion to the relinquished quantum of Connectivity corresponding to the ATS and terminal bay(s), construction of which has already been awarded for implementation. Conn-BG1 shall be returned in terms of Regulation 16.1 considering full capacity after excluding such relinquished quantum.

Relinquishment of GNA

- STU may relinquish GNA on behalf of identified intra-State entity. The relinquishment charges shall be equal to 24 times the transmission charges paid by such intra-State entity for the last billing month under the Sharing Regulations, corresponding to the relinquished quantum.

Transmission Charges

- Transmission charges towards ISTS -to be paid by the entities drawing power from ISTS.

- Under the prevailing arrangement, the buying entities pay the transmission charges either explicitly or implicitly by way of transmission charge being embedded in the sale price of the seller.

- Payment of transmission charges shall be as per CERC(Sharing of inter-state transmission charges and losses)Regulations,2020 as amended from time to time.

Draft Indian Electricity Grid Code (IEGC) 2022

Draft IEGC 2022 : Structure

Existing IEGC 2010	Draft IEGC 2022
1. General 2. Role of various organizations and their linkages 3. Planning code for inter-state transmission 4. Connection code 5. Operating code 6. Scheduling and despatch code 7. Miscellaneous	1. Preliminary 2. Resource planning code 3. Connection code 4. Protection code 5. Commissioning and commercial operation code 6. Operating code 7. Scheduling and Despatch code 8. Cyber security 9. Monitoring and compliance code 10. Miscellaneous

Chapter 1

Preliminary

Chapter 2

Resource Planning Code

Resource Planning Code

- New Chapter added
- Covers the integrated resource planning including
  - Demand forecasting,
  - Generation resource adequacy planning and
  - Transmission resource adequacy assessment, required for secure grid operation.

Demand Forecasting

Sl no	Entity	Assignment	Timeline
5.2(i)	Each distribution licensee within a State	Estimate the demand in its control area including the demand of open access consumers and factoring in captive generating plants, energy efficiency measures, distributed generation, demand response, for the next five (5) years starting from 1st April of the next year. 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.	Submit the same to the STU by 31st July every year
5.2(ii)	STU	Estimate the demand for the entire State duly considering the diversity for the next five (5) years starting from 1st April of the next year. Based on input received from distribution licensee	30th August every year
5.2(iii)	Forum of Regulators	may develop guidelines for demand estimation by the distribution licensees for achieving consistency and statistical accuracy by taking into consideration the factors such as economic parameters, historical data and sensitivity and probability analysis	No timeline given

Generation Resource Adequacy Planning

Sl no	Entity	Assignment	Timeline
5.3(a)	Each distribution licensee	(i) assess the existing generation resources and identify the additional generation resource requirement to meet the estimated demand in different time horizons, (ii) prepare generation resource procurement plan.	After the demand estimation
5.3(d)	STU	on behalf of the distribution licensees in the State shall provide to NLDC, • the details regarding demand forecasting, • Assessment of existing generation resources • Such other details as may be required for carrying out a national level simulation for generation resource adequacy for States.	By 30th September every year
5.3(e)	NLDC	• Based on the information received NLDC shall carry out a simulation to assist the States in drawing their optimal generation resource adequacy plan. • The simulation carried out by NLDC for this purpose shall be considered merely an aid to the distribution licensees. distribution licensees shall be responsible for all commercial decisions on generation resource procurement	By 31st October every year
5.3(f)	Each distribution licensee	• Each distribution licensee shall ensure demonstrable generation resource adequacy as specified by the respective SERC for the next five (5) years • Failure of a distribution licensee to meet the generation resource adequacy target approved by the SERC shall render the concerned distribution licensee liable for payment of resource adequacy noncompliance charge as may be specified by the respective SERC	
5.3(g)	Forum of Regulators	For the sake of uniformity in approach, FOR may develop a model Regulation stipulating inter alia the methodology for generation resource adequacy assessment, generation resource procurement planning and compliance of resource adequacy target by the distribution licensees.	No timeline given

Transmission resource adequacy assessment

Sl no	Entity	Assignment	Timeline
5.4(a)	CTU	CTU shall undertake assessment and planning of the inter-State transmission system as per the provisions of the Act and shall inter alia take into account : 1. adequate power transfer capability across each flow-gate 2. import and export capability for each control area; 3. import and export capability between regions; and 4. cross-border import and export capability.	Continuous process
5.4(b)	STU	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: 1. import and export capability across ISTS and STU interface; and 2. adequate power transfer capability across each flow-gate.	Continuous process

Chapter 3

Connection Code

GENERAL

- Connectivity, procedure and requirements for physical connection and integration of grid element.
- Connectivity to the ISTS shall be granted by CTU.
- All the Transmission licensees shall comply with the technical requirements specified under this Connection Code.
- After grant of connectivity and prior to the trial run for declaration of commercial operation, the tests as specified under this Code shall be performed.
- All the Transmission licensees shall comply with all the respective CEA/CERC Regulations.

PROCEDURE FOR CONNECTION

- The grant of connectivity to the ISTS by the CTU
- Detailed NLDC first time charging procedure for energization and integration of new or modified power system element.
- Requisite format submission as per the FTC Procedure.
- SLDC first time charging procedure for intra-state elements.

Connectivity Agreement

- In **case of users** seeking connectivity to the ISTS under GNA Regulations, Connectivity Agreement shall be signed between such users and the CTU.

- In **case of an inter-State transmission licensee**, Connectivity Agreement shall be signed between such licensee and CTU.

Technical Requirements

- Joint study by CTU/NLDC or RLDC shall carry out a joint system study six (6) months before the expected date of first energization.

- Similar exercise shall be done by SLDC in consultation with STU for the intra-state system.

Data and Communication Facilities

- Reliable speech and data communication systems shall be with NLDC, RLDC and SLDC.

- The associated communication system to facilitate data flow up to appropriate data collection point on CTU system including inter-operability requirements shall also be established.

- Real time data communication shall be established with all the concerned.

Chapter 4

Protection Code

Protection Code

- General
- Protection Protocol
- Protection Settings
- Protection Audit Plan
- System Protection Scheme (SPS)
- Recording Instruments

Protection Code : General

Uniform protection protocol for the users of the grid

- For **proper co-ordination of protection system** in order to isolate the faulty equipment and avoid unintended operation of protection system;
- To have a **repository of protection system**, settings and events at regional level;
- Specifying **timelines** for submission of data;
- To ensure **healthiness of recording equipment** including time synchronization; and
- To provide for **periodic audit** of protection system.

Protection Code : Protection Protocol

All Users

- Provide and maintain effective protection system as per
- Back-up protection system to protect an element in the event of failure of the primary protection system.

RPC

- To develop/review/revise the protection protocol in consultation with the stakeholders in the concerned region

Guided by

- CEA Technical Standards for Construction,
- the CEA Technical Standards for Connectivity,
- CEA (Grid Standards) Regulations, 2010
- CEA (Measures relating to Safety and Electric Supply) Regulations, 2010
- CEA Technical Standards for Communication.
- Any other standards by CEA specified from time to time

Any protocol change depending on operational scenario

- Deliberation and approval of the concerned RPC.

Necessary protection | **Protection Protocol** | **Intimation and Approval for Any change**

Protection Code : Protection Settings

All Users

- Ensure correct and appropriate settings of protection as specified by RPC.
- Ensure proper coordinated protection settings.
- Furnish the protection settings to RPC.
- Obtain approval of the concerned RPC for (i) any revision in settings, and (ii) implementation of new protection system
- Intimate to the concerned RPC about the changes implemented: **within Fortnight**

RPC

- Maintain a centralized database for grid elements connected to 220 kV and above
- Provide database access with different access rights
- Review of the protection settings
- Assess the requirement of revisions in protection settings and revise protection settings in consultation with the stakeholders: **At least once in a year**.
- Carry necessary studies by RPC for protection coordination and inform User/STU/CTU/ : **Twice a year**

Protection Database | **Protection Review Study** | **Intimation and Approval for Any change**

Protection Code : Protection Audit Plan

Types of protection audit : Internal and Third Party

Users

- Conduct annual internal protection audit: Rectification of findings and information to RPC.
- Conduct third-party protection audit for substations above 220 kV
  - Once in Five years or earlier as advised by RPC
  - Submit third-party audit report to RPC
  - Action plan within one month after report submission to RPC/RLDC
- **Submission of Annual audit plan for next financial year to RPC: 31st October**
- Adhere to the annual audit plan and report compliance to RPC

RPC

- Event Analysis and identity substations and generating stations for third party protection audit
  - User to complete audit within three months.
- Monitoring of Annual audit plan and compliance PC

Audit format provided

Internal &Third-party Audit | Protection Audit Timeline | Compliance Monitoring | Audit Format

Protection Code : Protection Audit Plan…

Users

- Submit protection performance indices to RPC (Monthly Basis for last month)
  - Dependability Index (*Nc/Nc+Nf)*
  - Security Index (*Nc/Nc+Nu)*
  - Reliability Index (*Nc/Nc+Ni)*
  - Reasons for performance indices < 1 for individual element-wise protection system
  - Action plan for corrective measures.

RPC

- Regular follow up on action plan
- RPC to approach commission for non-Compliance of protection protocol or failure to undertake identified remedial action within the specified timelines,

Performance Indices | **Action Plan Monitoring and Follow-up** | **Non-Compliance to CERC**

Protection Code : System Protection Scheme (SPS) & Recording Instruments

- SPS to have redundancies in measurement of input signals and communication paths involved up to the last mile
- Users/SLDCs to report **SPS operation within three days of operation** to RPC/RLDC in format
- RPCs to perform **regular dynamic studies and mock testing (at least once in a year) of SPSs**
- Users shall keep the recording instruments (disturbance recorder and event logger) in proper working condition.
- Disturbance recorders to have time synchronization and a **standard format for recording analogue and digital signals** which shall be included in the guidelines issued by the respective RPCs.

SPS Redundancy

SPS study and Mock test plan

DR Standardization

Chapter 5

Commissioning and Commercial Operation Code

General

Chapter covers aspects related to

- Drawal of startup power from and injection of infirm power into the grid
- Trial Run Operation
- Documents and tests required to be furnished before declaration of COD
- Requirements for declaration of COD.

Drawal of start up power and injection of infirm power

- Before COD, Generator can draw start up power for various testing activities.
- The period for which such interchange shall be allowed shall be as follows :-
  - 15 months prior to first synchronization and 6 months after the date of first synchronization.
  - Injection of infirm power shall not exceed 6 months from the date of first synchronization.
- Commission can extend the timeline if necessary.
- Start-up power shall not be used by the generating station for the construction activities.
- The onus of proving drawal of start up power for testing activity and not for construction, lies with the generator.

Notice of trial run

- Trial run notice shall be given of not less than 7 days to the concerned RLDC and the beneficiaries.
- In case the repeat trial run is to take place within 24 hours of the failed trial run, fresh notice shall not be required.
- For trial operation of transmission system, the licensee shall give a notice of not less than 7 days to the concerned RLDC and CTU.

Trial run of thermal generating unit

- A thermal generating unit shall be in continuous operation at MCR for 72 hours on designated fuel.

With condition:

  - Short interruption shall be permissible with corresponding increase in duration of the test.
  - Average load should be above MCR.
  - Cumulative interruption is allowed up to 4 hours.

- In case generator fails to demonstrate MCR, Generator can de-rate the capacity of the generating unit or to go for repeat trial run.

Trial run of hydro generating unit

- A hydro generating unit shall be in continuous operation at MCR for 12 hours:

With condition:

  - Any interruption shall call for a repeat of trial run;
  - Average load should be above MCR.
  - If MCR can not be demonstrated for 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.

- In case generator fails to demonstrate MCR, Generator can de-rate the capacity of the generating unit or to go for repeat trial run.

Trial run of solar generating station

- Successful trial run of a solar inverter unit(s) aggregating to 50 MW and above shall mean flow of power and communication signal for not less than the period between sunrise to sunset in a single day.

With condition:

- The output below the corroborated performance level with the solar irradiation of the day shall call for repeat of the trial run
- 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.

Trial run of wind generating station

- Successful trial run of a wind turbine(s) aggregating to 50 MW and above shall mean flow of power and communication signal for a period of not less than 4 hours during periods of wind availability.

With condition:

- The output below the corroborated performance level with the wind speed of the day shall call for repeat of the trial run.
- 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.

TRIAL RUN (TR) OF STORAGE/HYBRID GENERATING STATION & TRANSMISSION SYSTEM

- TR of ESS duration is 1 cycle of charging and discharging of energy as per the design capabilities.
- TR of PSP duration is 1 cycle of turbogenerator and pumping motor mode as per the design capabilities up to the rated water drawing levels.
- Successful TR of a hybrid system shall mean successful trial run of individual source of hybrid system in accordance with the applicable provisions of these regulations.
- Trial run of a transmission system or an element shall mean continuous 24 hours MW/MVAr flow

Certificate of successful trial run (TOC/TRC)

- Objection regarding TOC may be raised within 2 days of issuance of the certificate and RLDC Shall reply within 25 days of such objection.

- After completion of successful trial run and compliance with all the requisite documents/test reports, RLDC shall issue a Trial Run Certificate

Declaration by generating company and transmission licensee

- Generating company/Transmission licensee should comply with all the CEA/CERC regulations.

- All the associated system must be commissioned.

- A certificate shall be signed by the authorized signatory not below the rank of CMD or CEO or MD.

DECLARATION OF COMMERCIAL OPERATION (DOCO) AND COMMERCIAL OPERATION DATE (COD)

- The last unit of the generating station shall be considered as the COD of the generating station.
- For DOCO of Idle Charged Transmission element, CTU certificate is required.
- For TBCB project, COD must be in compliance with TSA. A CTU Certificate is required.

Chapter 6

Operation Code

Operating code : General

No.	Clause	Changes with respect to old IEGC and Discussion
28.1	All entities such as NLDC, RLDCs, SLDCs, CTU, STUs, RPCs, power exchanges, QCAs, SNAs, licensees, generating stations and other grid connected entities shall at all times function in coordination to ensure stability and resilience of the grid and achieve maximum economy and efficiency in operation of power system.	a. "Resilience" aspect is introduced for the 1st time. b. Economy and efficiency is explicitly mentioned .
28.3 to 28.5	Operating procedure of NLDC,RLDC and SLDC	To be uploaded in website by NLDC and RLDC
28.6 to 28.8	24X7 manning of all control room	a. A transmission line owner who don't have any substation shall also have a 24X7 control room with proper manpower. b. Remote operation is allowed, provided that there will be no delay in execution of switching instruction from appropriate LDC c. SNA and QCA shall have round the clock coordination centres manned by qualified personnel

Operating code : SYSTEM SECURITY

No.	Clause	Changes with respect to old IEGC and Discussion
29.2.a-e	Isolation, Taking out of service and Switching off of an element of the grid	"(i) during emergency as per the Detailed Operating Procedure(s) of NLDC or RLDC or SLDC, as the case may be, where such isolation would prevent a total grid collapse or would enable early restoration of power supply;"

Clause 29.7 & 8: Tuning

1. AVR
2. Reactive power control loop
3. PSS
4. LVRT & HVRT

-Time line for tuning and other condition for taking up tuning activity like network changes, fault level changes etc are mentioned explicitly

-CTU has been distant from the responsibility of PSS tuning

Clause 29.10 & 1: Islanding

1. RPC to design islanding scheme for identified generating stations, cities and locations and ensure its implementation as per Grid standard regulation.

2. Review of scheme at least once in every **3 year**.

3. RLDC shall carry out mock drill of Islanding scheme in consultation with SLDC and other users involved once in every year.

Clause 29.12 & 13: Under frequency and df/dt defense mechanism

Table 2: 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: All states (or STUs) shall plan UFR settings and df/dt load shedding schemes depending on their local load generation balance in coordination with and approval of the concerned RPC.

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.

Clause 29.12 & 13: Under frequency and df/dt defense mechanism….

- Salient features of UFR designing and implementation:
  - **No time delay**.
  - **uniform spatial spread** of feeders selected for UFR and df/dt disconnection
  - **Telemetering** of feeder where UFR and df/dt is installed and real time monitoring by SLDC as well as **RLDC**.
  - Reporting of duration when the load in the selected feeders fall below desired load relief by **RLDC.**

Clause 29.14 : SPS….

- Demarcation between intra-regional, inter-regional and cross border SPS.
- NLDC permission for inter-regional and cross border SPS

Frequency Control:
Role of Inertia and Reserve

Clause 30 : FREQUENCY CONTROL AND RESERVES

- General:
  - Specification of frequency measurement resolution of **+/- 0.001** Hz.
  - Operating band **49.95-50.05** Hz
  - **Different reserve:**
    - Primary Reserve
    - Secondary Reserve
    - Tertiary Reserve
    - Black Start reserves
    - Voltage Control reserves:
  - Reserve will be operated as ancillary services.

Clause 30 : FREQUENCY CONTROL AND RESERVES

- 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.
- The mechanism of procurement, deployment and payment of SRAS and TRAS shall be as specified in the **Ancillary Services Regulations.**
- LDC to evaluate FRC after each grid event.

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Inertia and Primary reserve

- NLDC to decide minimum inertia requirement. For satisfying the minimum inertia requirement NLDC may **curtail wind, solar and wind-solar hybrid generation.**
- **Storage system and demand side response** are considered for primary response
- NLDC to declare Primary reserve requirement for reference contingency at the start of the financial year.
- **Electronically controlled** governing systems or frequency controllers mandated for generating units.

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Inertia and Primary reserve

- Frequency response obligation for each control area will be assessed and communicated to each control area by NLDC by 15th March for the next financial year.

TABLE 4: PRIMARY RESPONSE OF VARIOUS TYPES OF GENERATING UNITS

Fuel/ Source	**Minimum unit size/Capacity**	**Up to**
Coal/Lignite Based	200 MW and above	±5% of MCR
Hydro	25 MW and above non-canal based	±10% of MCR
Gas based	Gas Turbine above 50 MW	±5% of MCR (corrected for ambience temperature)
Wind/ Solar/Renewable Hybrid Energy Project* (commissioned after the date as specified in the CEA Technical Standards for Connectivity)^	Capacity of Generating station more than 10 MW and connected at 33 kV and above	10% of the maximum Alternating Current active power capacity in case of frequency deviations in excess of 0.3 Hz

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

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy : Inertia and Primary reserve

- Ripple factor and RGMO is removed and Dead band and FGMO introduced. Dead band up to 0.03 Hz allowed.
- Response time for primary reserve mentioned as follows:
  - Starting within 2 sec
  - Reaching up to desired level by 30 sec
  - Sustain up to 5 min
- Each area to assess FRC and share FRC along with **1 sec resolution data** with RLDC.
- RLDC shall assess FRC for region and NLDC for whole country considering cross border response as well.
- **Grading** of performance and direction of corrective action in case median response is below 75 % of desired response.

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Secondary Reserve

- Secondary reserve will replenish the primary reserve.
- Eligibility, procurement, deployment and sharing of cost of reserve will be as **Ancillary Services Regulations.**
- Minimum dead band is **+-10 MW in ACE.**
- Initially the SRAS control signal will be sent from NLDC , however once communication channel between RLDC and SRAS provider established.

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Secondary Reserve

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

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

Offset = Provision for compensating measurement error

- It will be responsibility of SLDC and RLDC to calculate Bf from past Frequency event response and apply proper offset value based on measurement error.
- Bf will be median of last 20 event FRC.
- SRAS can be operated in three mode on mutually agreement between RLDC, SLDC and NLDC:
  - Tie line Bias
  - Flat Frequency control-Current mode of operation
  - Flat Tie control-Current mode of operation

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Secondary Reserve

- ACE archival at resolution of **10 sec or less and** sharing of Data from SLDC to RLDC and from RLD to NLDC for reserve estimation.
- Response time of SRAS:
  - Starting within 30 sec
  - Delivering obligated capacity by 15 min
  - Sustain up to 30 min
- Reserve estimation methodology to be followed:
  - 99 percentile of positive and negative ACE during last financial year
  - 110 % of largest unit size in the respective regional control area or state control area plus load forecast error plus wind forecast error plus solar forecast error during the previous financial year.

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Secondary Reserve

- SERC may notify different methodology. In absence of SERC order ,SLDC have to follow the above method mentioned.
- SLDC and RLDC to submit secondary reserve requirement by **15th Feb** for next financial year as per above methodology.
- NLDC to update in website region and state wise reserve requirement break-up by **1st March** for next financial year.
- State to **ensure availability** of reserve on day ahead basis.
- If state fails to maintain the allocated reserve then NLDC may procure the reserve on behalf od state and allocate the cost to the state as per provision of Ancillary Service Regulations.
- NLDC and RLDC to reassess the reserve quantum on **day ahead and real time basis.**
- SRAS provider shall follow the CEA technical criteria for connectivity. RE and storage plant also need to have provision for AGC in accordance with CEA technical criteria for connectivity

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Tertiary Reserve

- NLDC to update in website region and state wise tertiary reserve requirement break-up by **1st March** for next financial year.
- State to **ensure availability** of reserve on day ahead basis.
- If state fails to maintain the allocated reserve then NLDC may procure the reserve on behalf od state and allocate the cost to the state as per provision of Ancillary Service Regulations.
- NLDC and RLDC to reassess the reserve quantum on **day ahead and real time basis.**

Clause 30 : FREQUENCY CONTROL AND RESERVES: Control Hierarchy: Tertiary Reserve

- Response time of TRAS:
  - Starting within 15 min
  - Sustain up to 60 min
- TRAS shall be activated and deployed by the appropriate load despatch center on account of following events:
  - To replenish the secondary reserve, in case the secondary reserve has been deployed continuously in one direction for fifteen (15) minutes for more than 100 MW;
  - Generation unit or transmission line outages;
  - Any such other event affecting the grid security.
- The control area wise performance of SRAS and TRAS shall be evaluated in accordance with the Detailed Procedure prepared by NLDC.

Operational Planning Timeline and activity list

No.	Clause	Changes w.r.t old IEGC and Discussion
31.1	**Operational Planning Time Horizon** a. Advance Operational planning by NLDC, RLDCs and SLDCs within their respective control areas: **Monthly and Yearly time horizons** in co-ordination with CTU, RPCs or STUs, as applicable. b. Operational planning shall be carried out in advance by NLDC, RLDCs and SLDCs within their respective control areas on **Intra-day, Day Ahead, Weekly time horizons**.	**Timeline for operational planning has been defined**
31.1	**Procedure and data format by NLDC/RLDC for following activity** • Operational planning analysis • Real-time monitoring, • Real-time assessments. **SLDC also to develop similar procedure**.	**Activities for operational planning has been defined**

Operational planning

Real time monitoring

Real time assessment

Demand Estimation

<table>
<tr><th>No.</th><th>Clause</th><th>Changes w.r.t old IEGC and Discussion</th></tr>
<tr><td>31.2</td><td>
Demand Estimation by SLDC

Daily/weekly/monthly/yearly (Frequency is same as existing IEGC)
Day ahead block-wise demand data estimation by SLDC for the daily operation and scheduling.
Revision in real-time demand estimate by SLDC if major change is observed and sharing with RLDC
Monthly and quarterly data for scenario preparation by RLDC/NLDC for ATC/TTC calculation: Node-wise morning peak, evening peak, day shoulder and night off-peak estimated demand (MW/MVAr) for the nodes 132 kV and above system.
Weekly and Monthly data for LGBR and Operational planning: Time block wise peak and off-peak demand (MW/MVAR) for load-generation balance planning as well as for operational planning analysis. Should cover net load aspect with distributed generation.

Demand estimate by RLDC/NLDC

RLDC to compute based on SLDC data and NLDC based on RLDC

SLDC/RLDC/NLDC

Compute forecasting error and analyse to reduce forecasting error and publish on website

</td><td>

In order to facilitate estimation of Total Transfer Capability /Available Transfer Capability on three month ahead basis, the SLDC shall furnish estimated demand and availability data to RLDCs. (Granularity on data added for ATC/TTC calculation)

Timeline for Demand Estimation in Draft IEGC 2022
<table>
<tr><td>Daily demand estimation</td><td>10:00 hours of previous day</td></tr>
<tr><td>Weekly demand estimation</td><td>First working day of previous week</td></tr>
<tr><td>Monthly demand estimation</td><td>Fifth day of previous month</td></tr>
<tr><td>Yearly demand estimation</td><td>31st August of the previous year</td></tr>
</table>

</td></tr>
</table>

Generation and Adequacy Estimation

No.	Clause	Changes w.r.t old IEGC and Discussion
31.2	**Generation Estimation** • Entities to provide generation estimation **(Procedure to be developed)** • RLDC to forecast generation from wind and solar generating stations which are regional entities for operational planning. **Adequacy of Resources** **SLDCs :** • Estimate and ensure adequacy of resources • Identify generation reserves, demand response capacity and generation flexibility requirement • Furnish time block-wise information for the following day in respect of all intra-state entities to RLDC **RLDCs :** Validate adequacy of resources based on SLDC data • Demand forecast aggregated for the control area; • Renewable energy generation forecast for the control area • Injection schedule for intra-State entity generating station • Requisition from regional entity generating stations	• **New caluse**

Operational Planning Study

<table>
<tr><th>No.</th><th>Clause</th><th>Changes w.r.t old IEGC and Discussion</th></tr>
<tr><td>33.1</td><td>Based on the operational planning analysis data, operational planning study shall be carried out by various agencies for time horizons
<table>
<tr><th>Time horizon of operational planning study</th><th>Agency</th><th>Means for carrying out study</th></tr>
<tr><td>Real time and Intra-day</td><td>NLDC, RLDC, and SLDC</td><td>At least fifteen (15) minutes interval using online/offline SCADA/EMS system</td></tr>
<tr><td>Day-ahead</td><td>NLDC, RLDC, and SLDC</td><td>For various operating conditions using offline tools</td></tr>
<tr><td>Weekly</td><td>NLDC, RLDC, and SLDC</td><td>For various operating conditions using offline tools</td></tr>
<tr><td>Monthly/Yearly</td><td>RPC</td><td>For various operating conditions using offline tools</td></tr>
</table>
</td><td>New clause</td></tr>
</table>

Operating code

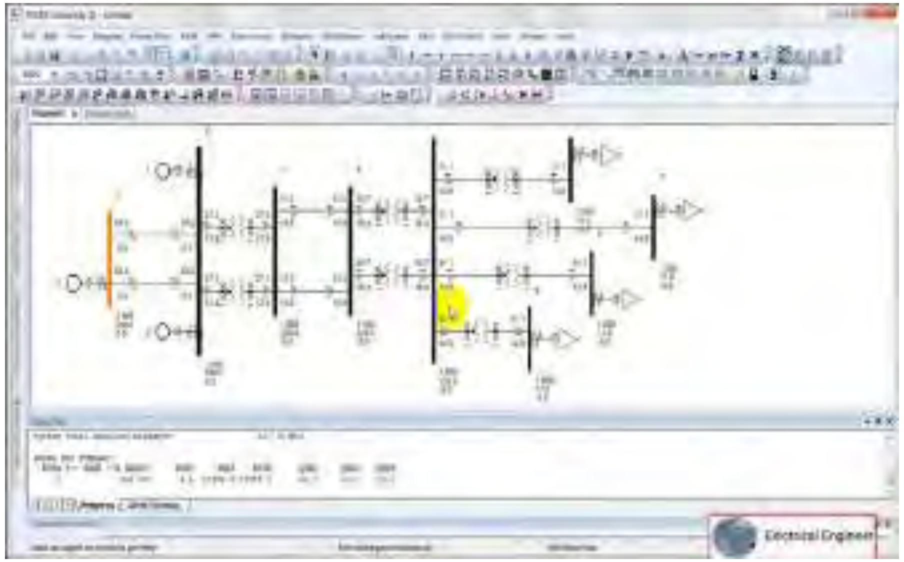
Operational Planning Study : Real time and Intra-day

No.	Clause	Changes w.r.t old IEGC and Discussion
33.2	• SLDCs, RLDCs and NLDC **shall utilize network estimation tool** integrated in their EMS, and SCADA system for the **real-time operational planning study**. **(Use of State Estimation)** • All users shall make available at all times **real-time error free operational data** for successful execution of network analysis using EMS/SCADA. Failure to make available such data shall be immediately reported to the concerned SLDC, the concerned RLDC and NLDC along with firm timeline for restoration. • The **performance of online network estimation tools** at SLDC and RLDC shall be reviewed in the monthly operational meeting of RPC. • Any **telemetry related issues impacting the online network estimation tool** shall be monitored by RPC for its early resolution.	**High Importance to State Estimator at NLDC, RIDCs and SLDCs** **Data Availability, Correctness, Monitoring at RPC** 

State Estimator | Telemetry | Data Availability | Data Correctness | Monitoring

Operating code

Operational Planning Study: Day-Ahead, Weekly, Monthly and Yearly

No.	Clause	Changes w.r.t old IEGC and Discussion
33.3-33.8	**SLDCs to perform day-ahead, weekly, monthly and yearly operational studies for the concerned State for:** 1. ATC/TTC at Intra state level 2. planned outage assessment 3. special scenario assessment; 4. system protection scheme assessment 5. natural disaster assessment; and 6. Any other study relevant in operational scenario. **RLDCs and NLDC shall perform day-ahead, weekly, monthly and yearly operational study for:** 1. TTC and ATC at inter-regional, intra-regional and inter-state level 2. Planned outage assessment 3. Special scenario assessment; 4. System protection scheme assessment 5. Natural disaster assessment; and 6. Any other study relevant in operational scenario • **Study Records to be maintained** • **Operating plans to address potential deviations of system operational limit** • **Deviation observed to be discussed in OCC and submitted to CEA &CERC**	**New clause** 

Operating code

Operational Planning Study: Day-Ahead, Weekly, Monthly and Yearly

No.	Clause	Changes w.r.t old IEGC and Discussion
33.9-33.11	**New Element integration impact Study (Next Six Months)** • SLDC: Intra-state system : Impact on ATC/TTC • RLDC: (a) the ISTS of the region and (b) the intra-state system on the inter-state system. • NLDC: (a) inter-regional system, (b) cross-border link and (c) intra-regional system on the inter-regional system.	**New clause**
33.12	**New Element Result Validation** • Compare results of new elements impact with those of the interconnection and planning studies by CTU/STUs, • Discuss and communicate variation with CTU and STUs for immediate and long-term mitigation measures.	**New clause**
33.13	**Defense Mechanism** Defense mechanisms like system protection scheme, load rejection scheme, generation run-back, islanding scheme or any other scheme for system security shall be proposed by concerned user or SLDC or RLDC or NLDC and shall be deployed as finalized by the respective RPC.	**5.2.0 :** All Users, STU/SLDC , CTU/RLDC and NLDC, shall also facilitate identification, installation and commissioning of System Protection Schemes (SPS) (including inter-tripping and run-back) in the power system to operate the transmission system closer to their limits and to protect against situations such as voltage collapse and cascade tripping, tripping of important corridors/flow-gates etc..

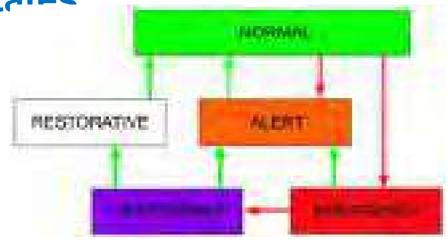
System Restoration

No.	Clause	Changes w.r.t old IEGC and Discussion
34.1	**Harmonization of Restoration procedure** • Template issued by NLDC: • All SLDC of each State and RLDC of each region to prepare restoration procedures for the grid and update them annually	**New clause**
34.3	**Mock run: At least Annual**	**Mock Run: Once in six months**
34.4	**Simulation study by all Users in coordination with RLDC for preparing their plan** • Black start capability of generator • Ability of black start generator to build cranking path and sustain island • Impact of block load switching in or out • Line/transformer charging • Reduced fault levels • Protection settings under restoration condition.	**New clause**
34.5	**House Load Operation of Thermal and Nuclear plan as per design and report of performance when operation is required.**	**New clause**

System Restoration

No.	Clause	Changes w.r.t old IEGC and Discussion
34.7	**Statutory Power during restoration:** SLDC, RLDC and NLDC are authorized • Operate with reduced security standards for voltage and frequency • Direct for implementation operational measures, namely, suspension of secondary or tertiary frequency control, power market activities, defense schemes, reduced governor droop setting as necessary **Black Start Support payment to generators during restoration** Any entity extending black start support by way of injection of power as identified in clause (6) of this Regulation shall be paid for actual injection @ 110 % of normal rate of charges for deviation in accordance with DSM Regulations for the last block in which the grid was available.	**Updated clause with more clarity** **New Clause**

Operating code
Real Time Operation

No.	Clause	Changes w.r.t old IEGC and Discussion
35.1	**Power System State: Normal/Alert/Emergency/Extreme Emergency /Restorative**	**Defined Power System States** 
35.2	**RLDC with NLDC/SLDCs : Carryout Study to evolve criteria for power system state based on past data and events**	**Criteria to be evolved**
35.4	**Procedure for Events** **SLDC :** For an event on intra-State transmission system having impact the inter-State transmission system : Inform RLDC **User :** For event on the ISTS or relating to a regional entity : Inform RLDC **RLDC:** Event on regional grid : Inform the concerned users and the concerned SLDC for necessary action.	**Event report procedure**
35.5	**Operational coordination** • Round the clock Control center/coordination center: All ISTS licensee, generating station, QCA and SNA • Any planned operation activity in ISTS system [such as transmission element opening or closing (including breakers), **protection system outage, SPS outage and testing etc.**] shall be done by taking operational code from RLDC or NLDC, as the case may be.	**5.1 : More clarity** **5.6.2.b :** All operational instructions given by RLDC and SLDC shall have unique codes which shall be recorded and maintained as specified in Central Electricity Authority (Grid Standards) Regulations, 2010

Post Despatch Analysis: Operational Analysis & Event reporting

<table>
<tr><th>No.</th><th>Clause</th><th>Changes w.r.t old IEGC and Discussion</th></tr>
<tr><td>37.1</td><td>NLDC, RLDCs & SLDCs to analyse and bring out public domain reports:

Pattern of demand met, frequency profile, voltage and tie-line flows, angular spread, area control error, reserve margin, ancillary services despatched, transmission congestion and (n-1) violations;
Generation mix in terms of source and station wise generation;
Irregular pattern in any of the system parameters mentioned and reasons thereof
Extreme weather events or any other event affecting the grid security.

RLDCs: Prepare a quarterly report for system constraints, details of actions taken, responsibility for causing disturbances in the system parameters. Report to be shared with RPCs.

Data shall be stored by SLDCs, RLDCs and NLDC > 15 years
Reports shall be stored > 25 years for operational analysis.
</td><td>More Clarity on Analysis report and timeline for event reporting

Timeline for Event Report in Draft IEGC 2022
<table>
<tr><th>Sr. No.</th><th>Grid Event^ (Classification)</th><th>Flash report submission deadline (users/ SLDC)</th><th>Disturbance record and station event log submission deadline (users/ SLDC)</th><th>Detailed report and data submission deadline (users/ SLDC)</th><th>Draft report submission deadline (RLDC/ NLDC)</th><th>Discussion in protection committee meeting and final report submission deadline (RPC)</th></tr>
<tr><td>1</td><td>GI-1/GI-2</td><td>8 hours</td><td>24 hours</td><td>+7 days</td><td>+14 days</td><td>+30 days</td></tr>
<tr><td>2</td><td>Near miss*</td><td>8 hours</td><td>24 hours</td><td>+7 days</td><td>+30 days</td><td>+30 days</td></tr>
<tr><td>3</td><td>GD-1</td><td>8 hours</td><td>24 hours</td><td>+7 days</td><td>+14 days</td><td>+30 days</td></tr>
<tr><td>4</td><td>GD-2/GD-3</td><td>8 hours</td><td>24 hours</td><td>+7 days</td><td>+21 days</td><td>+30 days</td></tr>
<tr><td>5</td><td>GD-4/GD-5</td><td>8 hours</td><td>24 hours</td><td>+7 days</td><td>+30 days</td><td>+30 days</td></tr>
</table></td></tr>
<tr><td>37.2</td><td>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 : report to RLDC/SLDC/RPC : 24 Hours detail should be submitted</td><td>New Clause</td></tr>
<tr><td>37.2.j</td><td>Monthly report by user on protection system issues to be shared to RLDC/RPC by first week in next month</td><td>New Clause</td></tr>
</table>

Operating code

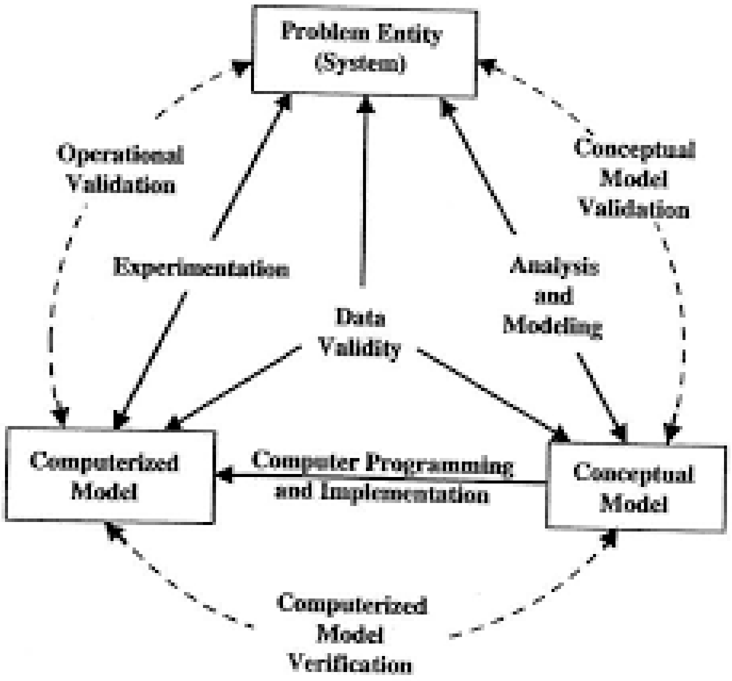
Reactive Power Management : Shifted from Scheduling to operation code

No.	Clause	Changes w.r.t old IEGC and Discussion
	▪ All generating stations shall be capable of supplying dynamically varying reactive power support so as to maintain power factor within the limits as per the CEA Connectivity Standard Regulations	
	▪ Periodic or seasonal tap changing of inter-connecting transformers and generator transformers shall be carried out to optimize the voltages and if required, other options such as tap staggering may be carried out in the network.	GT Tap change has been included
	▪ Hydro and gas generating units having capability shall operate in synchronous condenser mode operation as per instructions of RLDC or SLDC of the respective control area. Standalone synchronous condenser units shall operate as per instructions of RLDC or SLDC, as per respective control area.	Synchronous condenser mode included
	▪ NLDC, RLDCs or SLDCs to direct the users : Reactive power set-points, voltage set-points and power factor control to maintain the voltage at interconnection points.	Reactive power setpoint for devices
	▪ NLDC, RLDCs and SLDCs to assess : Dynamic reactive power reserve available at various substations or generating stations under any credible contingency.	Dynamic reactive power reserve study for credible contingencies

Operating code

Field Testing for Model Validation

- **Periodic tests on power system elements**
  - Ascertaining correctness of mathematical models used for simulation studies
  - Ensuring desired performance during an event in the system.
- **Responsibility**
  - Owner of the power system element
    - Report submission to NLDC, RLDCs, CEA and CTU for all elements
    - Report submission to STUs and SLDCs for intra- State elements.
- **Test Plan**
  - Equipment owners to submit testing plan for the next year : RPC by 31st October
  - Any change in the schedule to be informed to RPC in advance
- **Test Periodicity**
  - Once in every five (5) years OR
  - Major retrofitting
  - OR if necessitated earlier due to any adverse performance observed during any grid event.
- **Report recommendation :** Equipment owner to implement in consultation with RPC, NLDC, RLDC, CEA and CTU.



Operating code

Field Testing for Model Validation

Power System Elements	Tests	Applicability
Synchronous Generator	(1) Real and Reactive Power Capability assessment. (2) Reactive Power Control Capability (As per CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007) assessment. (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. (6) Any other test as required for ensuring proper validation of generator performance	Individual Unit of rating 100MW and above for Coal/lignite, 50MW and above gas turbine and 25 MW and above for Hydro.
Non-synchronous Generator (Solar/Wind)	(1) Real and Reactive Power Capability for Generator (2) Power Plant Controller Function Test (3) Frequency Response Test (4) Fault Ride through Test (sample testing of a unit in the generating stations).	Applicable as per CEA (Technical Standards for Connectivity to the Grid) Regulations, 2007
HVDC/FACTS Devices	(1) Damping capability of HVDC/FACTS Controller (2) Frequency Controller Capability of HVDC Controller (3) Reactive Power Controller (RPC) Capability for HVDC/FACTS (4) Validation of voltage-dependent current order limiter (VDCOL) characteristic for ensuring proper validation of HVDC performance (5) Filter bank adequacy assessment based on present grid condition. (6) Validation of response by FACTS devices as per settings.	To all ISTS HVDC as well as Intra-State HVDC/FACTS

Chapter 7

Scheduling And Despatch Code

Key Highlights

- Introduction of GNA, T-GNA, SCUC & SCED(Presently pilot).
- Changes in timeline for schedule & despatch
- DC declaration now mandatory for all regional generating station(including IPP) on day ahead.
- RLDC shall ask each regional generating station to demonstrate the DC (at least once in year)
- Generating station may sell its requisition surplus (URS) as available in DAM (without beneficiaries' consent)
- 110% overloading permitted for Hydro generator
- Curtailment procedure is not clear about force outage
- RE, RE-hybrid & run of river hydro plant with pondage get primary insulation in case of curtailment
- Mention of mandatory ramp rate for generators

No.	Clause	Changes with respect to old IEGC and Discussion
43	4. The entities connected only to inter-State transmission system shall be under control area jurisdiction of RLDCs for scheduling and despatch of electricity for such entities. 5. Entities connected to both inter-State transmission system and intra-State transmission system shall be under control area jurisdiction of RLDC, if more than 50% of quantum of connectivity is with ISTS, and………………………..	a. Earlier control area jurisdiction for scheduling and dispatch is based on % share.
44.1	Responsibility of RLDC	a. Optimisation of scheduling (SCED) b. Running of a Security Constraint Unit Commitment (SCUC)
44.2	Responsibility of NLDC	a. Finalising SCED and SCUC through RLDCs and publishing the same on its website b. in case of congestion, allocating available transmission corridors among Power Exchange(s) in ratio of initial unconstrained MCV.

No.	Clause	Changes with respect to old IEGC and Discussion
45.1 to 45.3	Details of Regional generating stations & drawee entities published by RLDC	a. Generator: list shall be updated quarterly on its website along with details such as station capacity, allocated share of beneficiaries, contracted quantum by buyers and balance available capacity b. Drawee: List shall be updated quarterly on its website along with allocated or contracted quantum
45.5	Requirement for Commencement of Scheduling	a. LTA, MTOA & STOA are replaced with GNA & T-GNA & accordingly submit the documents to the respective RLDC before commencement of scheduling
45.8 to 45.9	Declaration of Declared Capacity & Ramping Rate for scheduling	a. RLDC shall ask each generating station, at least once in a year, to demonstrate the declared capacity b. Declared ramp rate not less • Coal or lignite fired plants:1 % • Gas power plants :3% • Hydro power plants: 10%

No.	Clause	Changes with respect to old IEGC and Discussion
45.10	Optimum Utilization of Hydro Energy	a. During spillage conditions, RLDC may allow to over load capability upto 10% of Installed capacity without the requirement of additional GNA.
45.11	Scheduling of renewable energy generating station by QCA	a. Appoint a QCA behalf of wind, solar or re-newable hybrid generating stations. b. NLDC shall notify a procedure for aggregation of pooling stations within six (6) months. c. QCA shall be registered with concerned RLDC for Coordinate and facilitate scheduling & settlement of deviations.
45.12	Minimum turndown level for thermal generating stations	a. Generating station on its own option may declare a minimum turndown level below 55% of MCR.

No.	Clause	Changes with respect to old IEGC and Discussion
45.14, 45.15	Allowed to schedule injection or drawal	a. Allowed to schedule injection or drawal only upto its effective GNA quantum or T-GNA quantum b. Generating station shall be allowed to draw power before COD or after COD, only after obtaining schedule for such drawal of power in accordance with a valid contract entered into by it with a seller or distribution licensee or through power exchange.

Procedure for Scheduling & Despatch for Inter-State Transaction

Time-Line	Activities	Responsible Agency
by 6 AM on 'D-1' day	Declaration of Declared Capacity by generating stations	Generating Station, QCA
7 AM on 'D-1' day	Entitlement of each beneficiary or buyer	RLDC
8 AM on 'D-1' day	Requisition of schedule by buyers who are GNA grantees	SLDC, Regional entities
9 AM on 'D-1' day	Allocation of corridors by RLDC for GNA grantees: • In case of constraint in transmission system, available transmission corridor against the GNA shall be intimated to drawee GNA grantees by **8.15 AM**. • GNA grantees shall revise their requisition **by 8.30 AM**	RLDC
9 AM on 'D-1' day	Requisition of schedule by T-GNA grantees	SLDC, Regional entities
9:30 AM on 'D-1' day	After allocating corridors to GNA grantees, RLDC shall issue final drawl schedules for T-GNA grantees. & release the balance corridors for DAM (Collective)	RLDC

Procedure for Scheduling & Despatch for Inter-State Transaction

Time-Line	Activities	Responsible Agency
10 AM to 11.30 AM of ‘D-1’	Power Exchange(s) shall open bidding window for day ahead collective transactions	Generating Station, QCA
by 12.00 Noon of D-1	PX(s) shall submit the day-ahead provisional trade schedules to NLDC	PX(s)
by 12.30 PM of ‘D-1’	NLDC shall validate the same from system security angle and inform the power exchange with revisions required, if any, due to transmission congestion	NLDC
by 1.00 PM of ‘D-1	PX(s) shall submit the final trade schedules to NLDC for regional entities and to SLDC for intra-State entities. RLDC shall release balance corridors after finalisation of schedules under DAM (Collective)	PX(s), RLDC
by 2.00 PM of ‘D-1	RLDC shall process exigency applications received till 1 PM of ‘D-1’ day for the ‘D’ day and update the availability of balance transmission corridors on its website.	RLDC
	The balance transmission corridor may be utilised 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.	

Security Constrained Unit Commitment

46.

1) The objective of SCUC is to commit a generating station or unit thereof, for maximisation of reserves in the interest of grid security, without altering the entitlements and schedule of the buyers of the said generating station in the day ahead time horizon.

2) Reserves shall be procured and deployed in accordance with the Ancillary Services Regulations, and SCUC shall supplement such procurement of reserves under certain conditions, as specified in this Regulation

3) SCUC shall be undertaken if the NLDC, in coordination with RLDCs and based on assessment of the power system condition, anticipates that there is likely to be a shortage of reserves despite efforts made to procure such reserves in accordance with Ancillary Services Regulations.

Process to Undertake SCUC on day ahead

Time-Line	Activities	Responsible Agency
By 1330 Hrs. (D-1day)	**NLDC publish** a tentative list of generating **stations or units** thereof, which are likely to be scheduled below the minimum turn down level, based on beneficiary requisitions and **initial unconstrained bid results of DAM** in power exchanges, **received till 1300 Hrs of the D-1 day**.	NLDC in coordination with RLDCs
By 1630 Hrs. (D-1day)	**Beneficiaries** of such stations shall be permitted to **revise their requisitions** from such stations **by 1630 Hrs of D-1 day**,shall be **final and binding after 1630 Hrs of D-1 day** and further reduction in drawal schedule shall not be allowed from such stations for such time blocks	Beneficiaries
After 1630 Hrs (D-1day)	NLDC prepare the final list of such generating units that are likely to go below their minimum turndown level & stacked generating units as per merit order. generating units so identified shall be **considered for undertaking SCUC**	NLDC in coordination with RLDCs
by 1800 Hrs (D-1day)	If the NLDC in coordination with RLDCs **anticipates shortfall of reserves** in D day, NLDC may **schedule incremental energy** from the generating units by 1800 Hrs. of D-1 day and update the list on the respective RLDC website	NLDC in coordination with RLDCs
	generating stations or units not brought on bar under SCUC, shall have the option to **operate at a level below the minimum turn down** level or to go under **Unit Shut Down (USD).**	

Provision Related to SCUC & USD

- In order **to maintain load generation balance** consequent to **scheduling of incremental generation**, the NLDC in coordination with RLDCs, shall make commensurate reduction in generation from the on-bar generating station(s),
- The generating station from which incremental energy has been scheduled shall be paid from the Deviation and Ancillary Services Pool Account, and the generating station from which reduction in generation has been directed shall pay back to the Deviation and Ancillary Services Pool Account.
- In case a generating station, or unit thereof, opts to go under unit shut down (USD), the generating company owning such generating station or unit thereof shall fulfil its **obligation to supply electricity to its beneficiaries who had made requisition from the said generating station prior to it going under USD**, by entering into a contract(s) covered under the Power Market Regulation or 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 supply is arranged.

Additional factors to be considered while finalising schedule

- **Security Constrained Economic Despatch (SCED)**
  - The generating stations, including those for which the tariff is determined by the Commission under Section 62 of the Act, willing to participate in SCED shall declare at their discretion, the variable charges upfront to NLDC on weekly basis
  - NLDC shall publish the Detailed Procedure for SCED within two months of the notification of these regulations after stakeholder consultation and intimate the Commission.
- **Margins for primary response**
  - RLDCs and SLDCs, as the case may be, shall not schedule the generating station or unit(s) thereof beyond ex-bus generation corresponding to 100% of the Installed capacity.
  - In case of gas or liquid fuel-based units, suitable adjustment in Installed Capacity should be made by RLDCs and SLDCs, 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
  - Hydro generating stations shall be permitted to schedule ex-bus generation corresponding to 110% of the installed capacity during high inflow periods to avoid spillage.
- **Curtailment of Scheduled transactions for grid security by RLDC**
  1. Bilateral transactions under T-GNA(other than RE)
  2. Bilateral transactions under T-GNA(RE)
  3. Collective transactions under day ahead market
  4. Collective transactions under real time market
  5. Transactions under gna(other than RE)
  6. Transactions under GNA (RE)

No.	Clause	Changes with respect to old IEGC and Discussion
47.3(b)	Reduction in generation by RLDC in the event of bottleneck	a. Generation and drawal schedules revised by the RLDC shall become effective from 7th block or 8th block
47.3	(d). Whenever RLDC revises final schedules due to reasons of grid security or contingency, brief reasons shall be informed immediately to the concerned entity followed by a detailed explanation to be posted on RLDC website within 24 hours. (e). Any verbal directions by RLDC shall be confirmed in writing as soon as possible latest within twenty-four hours.	a. posted on RLDC website within 24 hours
47.5	Grid disturbance	• Generation and drawal schedules revised by RLDC shall become effective from 7th block or 8th block. • Scheduled generation of all the affected regional entity generating stations supplying power under bilateral transactions revised as per actual.

No.	Clause	Changes with respect to old IEGC and Discussion
47.5	Grid disturbance	• Generation and drawal schedules revised by RLDC shall become effective from 7th block or 8th block. • Scheduled generation of all the affected regional entity generating stations supplying power under bilateral transactions revised as per actual. • Scheduled drawals of such beneficiaries or buyers shall be deemed to have been revised(only if affected) • scheduled generation of all the affected regional entity generating stations supplying power under collective transactions shall be deemed to have been revised to be equal.
47.11	Oversight of Injection or Drawal	• NLDC or RLDC, as the case may be, shall periodically review the over drawal from or under injection into the grid. In case of persistent over drawal or under injection, the matter shall be reported to the RPC and the Commission for necessary action.

Chapter 8

Cyber Security

48. GENERAL

- Deals with measures to be taken to safeguard the national grid from spyware, malware, cyber-attacks, network hacking, procedure for security audit 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, NLDC, RLDCs, SLDCs, CTU and STUs shall have in place, **a cyber security framework** in accordance with Information Technology Act, 2000; CEA (Technical Standards for Connectivity) Regulations, 2007; CEA (Cyber Security in Power Sector) Guidelines, 2021 and any such regulations issued from time to time, by an appropriate authority, so as to support reliable operation of the grid.

49. Cyber Security Audit

- All users 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.

CEA (Cyber Security in Power Sector) Guidelines, 2021

- Guidelines Issued on 7th October 2021, by CEA
- It is applicable to all responsible entities as well as System Integrators, Equipment Manufacturers, Suppliers/Vendors, Service Providers, IT Hardware and Software OEMs engaged in the Indian Power Supply System.

Article 1: Cyber Security Policy Article	Article 2: Appointment of CISO	Article 3: Identification of Critical Information Infrastructure (CII)	Article 4: Electronic Security Perimeter (ESP)	Article 5: Cyber Security Requirements Article
Article 6: Cyber Risk Assessment and Mitigation Plan Article	Article 7: Phasing out of Legacy System Article	Article 8: Cyber Security Training Article	Article 9: Cyber Supply Chain Risk Management Article	Article 10: Cyber Security Incident Report and Response Plan Article
Article 11: Cyber Crisis Management Plan(C-CMP)	Article 12: Sabotage Reporting	Article 13: Security and Testing of Cyber Assets	Article14: Cyber Security Audit	

50. Mechanism of Reporting

- All entities shall immediately report to the appropriate government agencies in accordance with the Information Technology Act, 2000 in case of any cyber-attack.

- NLDC, RLDCs, SLDCs, RPCs and the Commission shall also be informed by such entities in case of any instance of cyber-attack.

Chapter 9

Monitoring and Compliance Code

General

Assessment of compliance

- Periodical monitoring of compliance of regulations under IEGC
- All users, CTU,STUs, NLDC, RLDCs, SLDCs and RPCs

Monitoring of compliance : Two methodologies

- Self-Audit
- Compliance Audit

Self Audit

Conduct annual self-audits and submit the reports : 31st July of every year.

- **Should Contain information with respect to non-compliance:**
  - Sufficient information to understand how and why the non-compliance occurred
  - Extent of damage caused by such non-compliance
  - Steps and timeline planned to rectify the same
  - Steps taken to mitigate any future recurrence
- **Self-audit reports by users:** RLDCS or SLDCs (Monitoring agency)
- **Self-audit reports of NLDC, RLDCs, CTU, and RPCs :** Respective Commission (Monitoring agency)
- **Time-bound rectification plan with reasonable time**
  - Track the progress of compliances of users
  - Exceptional reporting for non-compliance to the appropriate Commission.

Regional Power Committee (RPC)

- Monitor the instances of non-compliance
- Endeavor to sort out all operational issues and
- Deliberate to reduce non-compliance by building consensus.
- Member Secretary to report any unresolved issues to the Commission.

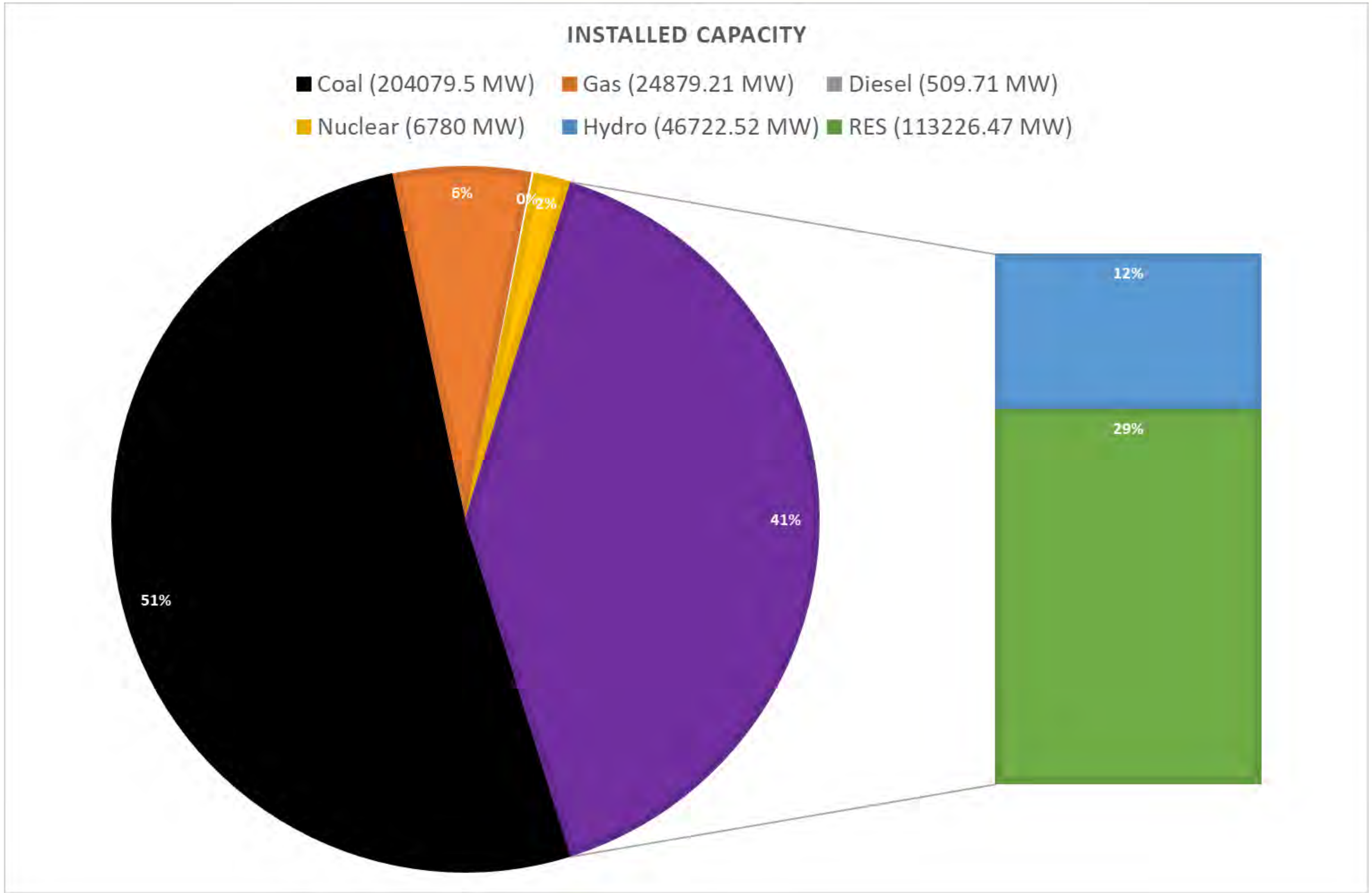
Third Party Auidt

Independent Third-Party Compliance Audit

- Commission may order independent third-party compliance audit for any user, CTU, NLDC, RLDC and RPC as deemed necessary based on the facts brought to the knowledge of the Commission.

Thank You

Total Installed capacity 402.82 GW as on May-2022



*Source CEA

Analogy between Frequency control and Cash flow

Inertia	Governor	Secondary	Tertiary
Creditability	Cash or Saving account	FD	Income from Profit

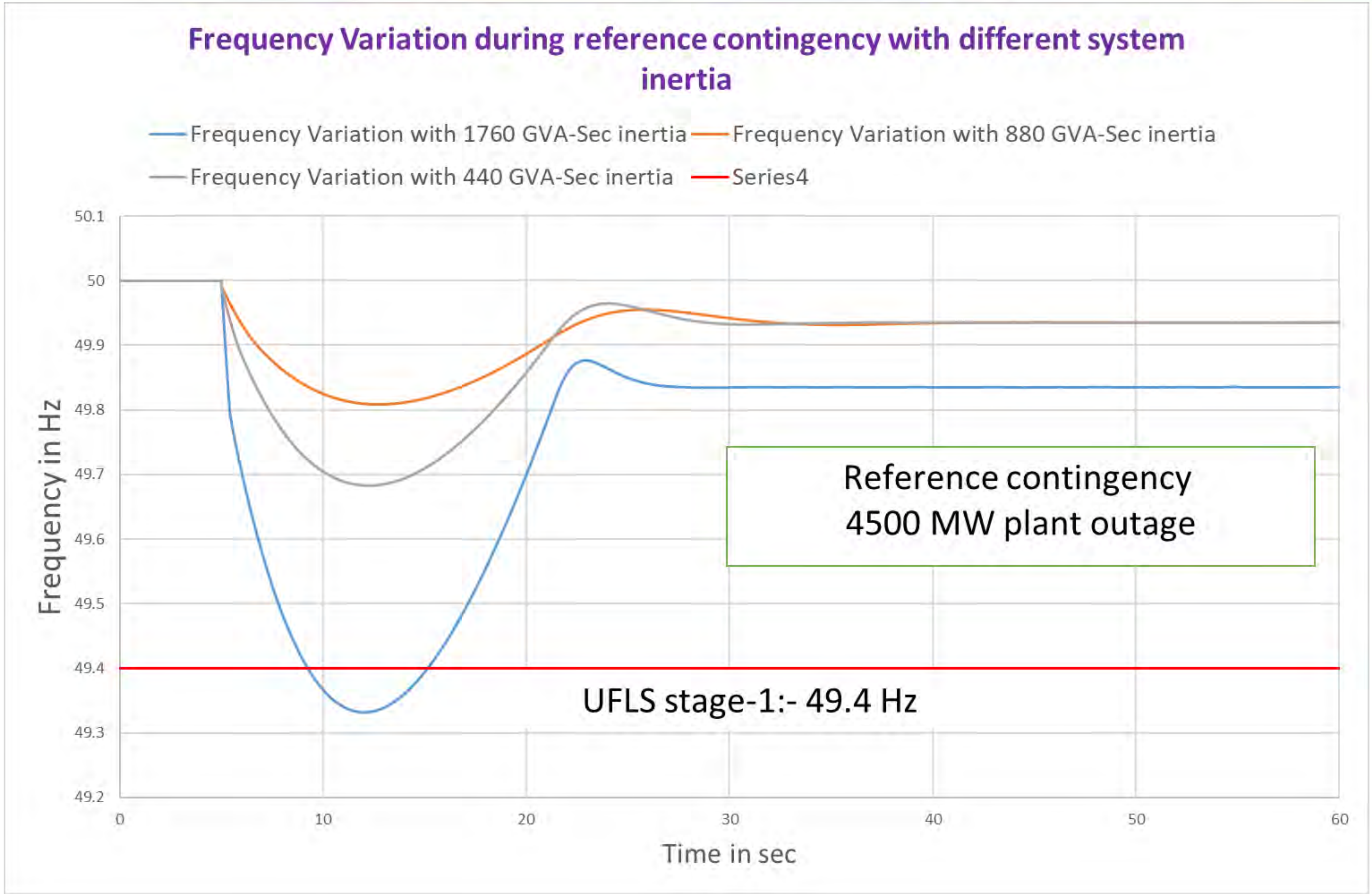
$$\text{All India minimum target frequency response characteristics} = \frac{Ref.Contingency}{0.3} = \frac{4500}{0.3} = 15000\ MW/Hz$$

$$FRO = \frac{(\text{Control Area average Demand} + \text{Control Area average Generation}) * \text{minimum all India Target Frequency Response Characteristic}}{(\text{Sum of peak or average demand of all control areas} + \text{Sum of average generation of all control areas})}$$

TABLE L: 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.*


Frequency Variation during reference contingency with different system inertia
Frequency Variation with 1760 GVA-Sec inertia
Frequency Variation with 880 GVA-Sec inertia
Frequency Variation with 440 GVA-Sec inertia
Series4
Frequency in Hz
50.1
50
49.9
49.8
49.7
49.6
49.5
49.4
49.3
49.2
0
10
20
30
40
50
60
Time in sec
Reference contingency
4500 MW plant outage
UFLS stage-1:- 49.4 Hz

‘**Minimum Turndown Level**’-means minimum station loading corresponding to the units on bar up to which a regional entity generating stations is required to be on bar on account of less schedule by its buyers or as per the direction of RLDC as detailed in Chapter 7 of this Code;

(12) Minimum turndown level for thermal generating stations

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

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

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

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

Draft (Flexible operation of thermal power plants),Regulation 2022 CEA