

North Eastern Regional Power Committee

Agenda For

141st OCC Sub-Committee Meeting

Time of meeting : 10:00 Hrs.

Date of meeting : 14th February, 2018 (Wednesday)

Venue : "Hotel RajMahal", Guwahati.

A. CONFIRMATION OF MINUTES

CONFIRMATION OF MINUTES OF 140th MEETING OF OPERATION SUB-COMMITTEE OF NERPC.

The minutes of 140th meeting of Operation Sub-committee held on 19th January, 2018 at Guwahati were circulated vide letter No. NERPC/SE (O)/OCC/2016/4556-4591 dated 30th January, 2018.

The Sub-committee may confirm the minutes of 140th OCCM of NERPC as no comments/observations were received from the constituents.

ITEMS FOR DISCUSSION

B.1. ACTION TAKEN:

1. IMPLEMENTATION OF PROJECTS FUNDED FROM PSDF:

The status as informed in 140th OCC:

State	Protection System	ADMS	Capacitor Installation	SAMAST**
Arunachal Pradesh	Requisition of funds by May-June 2018.	Clarification submitted to Techno-Economic Sub-group.	-	SLDC to apprise SERC of the project.
Nagaland	SE(C&O) informed that work is in progress.	Clarification submitted to Techno-Economic Sub-group.	To re-submit proposal to NERPC for Study.	Documents and relevant papers have been furnished to Nagaland SERC as desired by Chairperson, SERC. SERC has requested for a presentation at Kohima/Nagaland by the SAMAST group
Mizoram	-	Clarification submitted to Techno-Economic Sub-group.	Appraisal Committee is yet to approve	To furnish action plan.

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Manipur	Remaining tenders referred to Higher Tendering Committee. All LOAs by Feb'18.	Clarification submitted to Techno-Economic Sub-group.	Submitted to NERPC for Study before sending to NPC/NLDC.	NERPC/NERLDC members to meet SERC /MSPCL higher officials in 2 nd week of Feb'18.
Tripura	To submit UC by 04.02.18. Material 90% received at site.	Clarification submitted to Techno-Economic Sub-group.	To submit proposal to NERPC for Study.	NERPC/NERLDC members to meet TSERC /TSECL higher officials in 1 st week of Feb'18.
Assam	Remaining tenders' bidding document under scrutiny. All LOAs' by Aug'18.	Clarification submitted to Techno-Economic Sub-group.	-	DPR finalized.
Meghalaya	MePTCL-PLCC LoA by Feb'18 MePGCL -LOA completed.	Clarification submitted to Techno-Economic Sub-group.	-	DPR finalized.

The status of implementation of the above schemes (physical as well as financial progress) may please be reviewed and the entities are requested to expedite implementation of the schemes. The entities may also be advised to furnish status as per format by first week of every month on regular basis to Member Convener, PSDF Project Monitoring Group (AGM, NLDC, POSOCO) with a copy to NPC & NERPC. The LOAs of R&M Scheme are to be furnished to NERLDC/NERPC regularly.

States may please intimate the latest status.

2. Long Outage of Important Grid Elements:

Name of the Element	Name of Utility	Status as informed in 140th OCC	Latest status
63MVAR Reactor at Byrnihat to replace with 80MVAR Reactor	MePTCL	NERPC to pursue with NPC regarding exact status.	
400KV 80MVAR Bus Reactor at Palatana	OTPC	Unavailability of critical spare. By 15.03.2018 - CoD.	
132 kV Mariani (AEGCL) – Mokochung (DoP, Nagaland) S/C	AEGCL	Line cannot be charged due to low insulation. RCE of ₹ 43 lakhs to be sanctioned by Jan'18.	

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132 kV P K Bari – Silchar I & II	NERTS	Persistent RoW issues. By 15.02.2018 both circuit to be restored.	
132 kV Dimapur - Dimapur I	DoP Nagaland	By Jan'18 Bus up-gradation at Dimapur by DoP, Nagaland	
132 kV Hailakandi – Dullavcherra	AEGCL	By 15.02.2018.	
132 kV RHEP Bus B	NEEPCO	By Jan'18	
DHEP Unit 2	NEEPCO	GT failure. By Feb'18	
400/220 kV, 315 MVA ICT-II at BgTPP	NTPC	By 23.02.2018	
AGTCCPP Unit 4	NEEPCO	By 20.01.2018	

Utilities may please intimate the latest status.

3. Furnishing of various data for reliable grid operation:

Data regarding	Status as of 140 th OCC		Latest status
DAS output for FRC calculation	Event date: 09.12.17- BgTPP, OTPC, Khandong, Kopili Stg II data provided Event date: 10.01.18- Ranganadi		
Report on VDI	Submitted by SLDC of Assam (Daily and Monthly Basis), Meghalaya (Monthly Basis) and DoP, Nagaland		
DG healthiness report	OTPC, NTPC, Kopili, Khandong, Kopili Stg II, Nagaland, Mizoram submitted the data		
Technical & Commercial data for PoC (Q1 2018-19)	NEEPCO, OTPC, NHPC, DoP Arunachal Pradesh, MSPCL, AEGCL, MePTCL, P & ED Mizoram, DoP, Nagaland, TSECL submitted the data. MePTCL and TSECL to submit YTC data		
Operating Procedures	Items	Data submitted by	
	OP of States	Submitted only by AEGCL and MePTCL	
	OP of HVDC	Not Submitted	

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	OP of Transmission System	Not submitted by any constituents	
	OP of Generating Stations	Not submitted by any generators	
	OP of GIS	Not submitted by any constituents	
Data related to Power Map.	Items	Data submitted by	
	Communication (PLCC/OPGW/GPRS/SAT/Satellite)	List of lines mailed by NERLDC on 9 th January'18	
Data related to Single Line Diagram.	State SEM Location	Only Meghalaya submitted	

NERLDC has also requested that Water level, inflow details, discharge quantity & Number of Gate opening (in case of spillage) of Hydro Plants be recorded on a 12 hour basis (2 entries in a day) and to be submitted to NERPC & NERLDC on a monthly basis for proper operational planning.

NERLDC may please inform the status.

B.2. OPERATIONAL PERFORMANCE AND GRID DISCIPLINE DURING JANUARY, 2018

As per the data made available by NERLDC, the grid performance parameters for January, 2018 are given below:

NER PERFORMANCE DURING JANUARY, 2018

States	Energy Met (MU)		w.r.t. Dec,17 % inc (+) /dec (-)	Energy Reqr. (MU)		w.r.t. Dec,17 % inc (+) /dec (-)	% inc (+) /dec (-) of energy reqr vs met. In Jan,18
	January-18	December-17		January-18	December-17		
Ar. Pradesh	67.09	66.94	0.22	68.05	67.97	0.12	-1.41
Assam	704.17	702.79	0.20	713.53	716.42	-0.40	-1.31
Manipur	83.57	79.23	5.48	84.50	80.44	5.05	-1.10
Meghalaya	190.17	149.54	27.17	190.17	149.54	27.17	0.00
Mizoram	59.65	55.56	7.36	60.38	56.61	6.66	-1.21
Nagaland	63.09	64.75	-2.56	71.43	73.09	-2.27	-11.68
Tripura	107.48	107.32	0.15	108.02	108.21	-0.18	-0.50
Region	1275.22	1226.13	4.00	1296.07	1252.28	3.50	-1.61

States	Demand Met (MW)		w.r.t. Dec,17 % inc (+) /dec (-)	Demand in (MW)		w.r.t. Dec,17 % inc (+) /dec (-)	% inc (+) /dec (-) of Demand vs met.
	Jan-18	Dec-17		Jan-18	Dec-17		

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							In Jan,18
Ar. Pradesh	134	136	-1.47	138	138	0.00	-2.90
Assam	1510	1453	3.92	1539	1479	4.06	-1.88
Manipur	195	187	4.28	202	194	4.12	-3.47
Meghalaya	331	368	-10.05	331	369	-10.30	0.00
Mizoram	96	95	1.05	105	104	0.96	-8.57
Nagaland	124	127	-2.36	152	155	-1.94	-18.42
Tripura	226	223	1.35	226	223	1.35	0.00
Region	2317	2314	0.13	2339	2333	0.26	-0.94

**REGIONAL GENERATION & INTER-REGIONAL
EXCHANGE IN MU**

AVERAGE FREQUENCY (Hz)

Month---->	Jan-18	Dec-17	Month---->	Jan-18	Dec-17
Total Generation in NER (Gross)	1329.102	1365.874		% of Time	% of Time
Total Central Sector Generation (Gross)	1013.558	1063.102	Below 49.9 Hz	11.07	12.86
Total State Sector Generation (Gross)	315.544	302.771	Between 49.9 to 50.05 Hz	78.01	73.86
Inter-Regional Energy Exchange			Above 50.05 Hz	10.92	13.93
(a) NER-ER	95.17	4.54	Average	49.98	49.98
(b) ER-NER	273.68	483.02	Maximum	50.29	50.25
(c) NER-NR	214.86	441.40	Minimum	49.62	49.70
(d) NR-NER	130.02	0.00			
© Net Import	93.67	37.08			

C. OLD ITEMS

1. Status of Generating Units, Transmission Lines in NER:

During 140th OCC meeting, the status as informed by different beneficiaries is as follows:

SN	Items	Status as given in 140 th OCC Meeting	Status as given in 141 st OCC Meeting
a. New Elements			
1	400/220kV, 315 MVA ICT-1 of NTPC at Bongaigaon	ICT-1 - Mar'18	
2	Kameng HEP of NEEPCO two units (2 x 150 MW) Next two units (2x150 MW)	Unit #1 - Mar'18	
3	Pare HEP of NEEPCO (2 x 55 MW)	Unit #1 - Mar'18	

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4	400 kV D/C Silchar - Melriat line of PGCIL	March, 2018.	
5	220kV Rangia - Salakati of AEGCL	March, 2018.	
6	132kV Monarchak – Surjamaninagar D/C of TSECL	CEA to revert back.	
7	400kV D/C Balipara – Kameng	March, 2018.	
8	RHEP 80 MVAR Bus Reactor	NERLDC, NERPC to conduct joint study.	
9	SLDCs (Ar. Pradesh, Manipur, Mizoram, Nagaland)	Ar. Pradesh - Mar'18 Manipur, Mizoram, Nagaland - CoD	
10	400/220 kV 315 MVA ICT-II at Bongaigaon	March, 2018.	
11	220/132 kV, 160MVA ICT-II at Balipara	ICT#II - delayed	
12	220/132 kV, 1x160 MVA ICT with GIS Bay at Kopili	March, 2018.	
13	400/132 kV, 1x315 MVA ICT-III at Silchar	March, 2018.	
14	Replacement of 2x315 MVA ICTs with 2x500 MVA ICTs at Misa (PG)	March, 2018.	
15	400 kV Silchar – Misa D/C	2019	
16	1x125 MVAR Bus Reactor at 400 kV at Balipara	March, 2018(LOA date).	
17	1x125 MVAR Bus Reactor at 400 kV Bongaigoan	March, 2018(LOA date).	
18	Tuirial HEP of NEEPCO	Unit #I -CoD pending Communication and Connection Agreement. Unit #II - Jan'18	
19	33kV bay at 220kV Mariani(AS) S/Sn	Metering issues to be taken up with APDCL by	

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		NERTS	
20	33kV Tezu-Tezu(AP)	-	
21	33kV bay for 132kV Badarpur(PG) S/Sn	APDCL to submit estimate to NERTS.	
22	Dedicated 33kV feeder at Khliehriat Substation from Lumshnong.	MeECL to revert back.	
23	Dedicated 33kV feeder for Badarpur Substation from Panchgram upper SS	APDCL to submit estimate to NERTS.	
b. Elements under breakdown/upgradation			
24	Up-gradation of 132 kV Lumshnong-Panchgram line	Approved by Techno-Economic sub-group for funding from PSDF.	
25	Switchable line Reactors at 400kV Balipara & Bongaigoan	Jan'18	
26	PLCC Panels at Loktak end of Loktak - Ningthoukhong 132 kV feeder and Loktak - Rengpang 132 kV feeder	May'2018	
27	LILO of 132kV Ranganadi - Nirjuli at Pare of NEEPCO by PGCIL	Jan'18	
28	LILO of 132kV Ranganadi - Itanagar (Chimpu) at Pare of Ar. Pradesh	Bay 1 at RHEP for Pare: Jan'18 Bay 2 at RHEP for Itanagar: Mar'18	
29	LILO portion of 132kV Ranganadi - Nirjuli(diversion work) at Lekhi by DoP Ar. Pradesh	Jan'18	
30	Re-conductoring of 132kV Umiam Stg#III - Umtru	SE, SLDC suspected that nomenclature might be wrong. MeECL to revert back.	
31	Upgradation of ULDC FO node	Target completion : June 2018	
32	HTLS reconductoring	Ckt - I : under progress.	

	of 132kV Agartala – RC Nagar – I	schedule for completion by Jan'18.	
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AEGL may please provide time schedule for takeover of dismantled 220/132kV 50MVA ICT at Balipara.

Concerned constituents may kindly intimate the status.

D. NEW ITEMS

D.1 Generation Planning (ongoing and planned outages)

NEEPCO & NHPC may kindly intimate the availability for hydro stations:

Generating Station	Units running	MW	MU	Reservoir
Khandong				
Kopili				
Kopili-II				
Ranganadi			Subject to inflow	
Doyang				
Loktak				
AGBPP	-	-	-	-
AGTPP	-	-	-	-

The outage of other generating stations may be approved considering the present water levels in reservoirs.

The Committee may discuss and approve the proposed shutdown by Generating Stations as given in Annexure – D.2 below.

D.2 Outage Planning Transmission elements

It was agreed in the 99th OCC meeting that shutdown will be availed only after approval is given by the OCC forum. It was also agreed that deferment/revision of outages elements other than already approved in OCC will be henceforth put/displayed in the website of NERPC (**under Operational Activities/OCC Approved shutdown**) as per CERC regulations/ CEA guidelines etc for ensuring smooth & secure grid operation.

Furnishing request of shut down of the element, which was approved by NERPC, by Indenting Agency (ISTS licensees/STUs/Generating Companies) to NERLDC: Planned shutdown approved by NERPC shall be considered for implementation by NERLDC on D-3 basis. If an outage is to be availed on say 10th of the month, the shutdown availing agency would reconfirm to NERLDC on 7th of the month by 10:00 Hr. This practice is necessary to ensure optimal capacity utilization and the time required for associated system study/coordination by/amongst RLDC/NLDC.

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In 130th OCCM, Member Secretary opined strongly about non commitments of earlier decision by the constituents and stated that all proposed plan shutdowns and agenda for the next OCC meeting should be sent to NERPC Secretariat latest by 5th day of next month. He directed SE(C&O) that the decision should be strictly adhere to and no shutdowns or agenda will be entertained after that stipulated date.

In 134th OCCM, it was decided that all communication related shutdown be approved in OCC forum only.

In 139th OCCM, SE(C&O), NERPC clarified that all shutdown proposals must be sent at least 6 working days before date of OCC meeting. Any proposal received after D-6 working days would not be entertained. After detailed deliberation, it was decided that in case OCC approved shutdown is not granted by RLDC due to grid constraints NERLDC would reschedule the shutdown on a date mutually agreeable with the utility.

The sub-Committee may kindly discuss and approve the transmission line outages proposed by Constituents for February, 2018- March,2018 at Annexure-D.2., which is available in the website of NERPC.

D.3 Estimated Transmission Availability Certificate (TAC) for the month of September, 2017& October,2017:

NETC and POWERGRID have submitted the outage data for the month of September 2017& October,2017. So the attributability of outage of the said elements may please be finalized.

Members may please discuss.

D.4 Assessment of Total Transfer Capability (TTC), Transmission Reliability Margin (TRM) and Available Transfer Capability (ATC) by SLDC on respective Inter-State Transmission Corridor

Updated PSS/E Base Cases have been **mailed to all the SLDCs on 01.02.18**. All SLDCs are requested to assess the Total Transfer Capability (TTC), Transmission Reliability Margin (TRM) and Available Transfer Capability (ATC) for the month of Mar'18 using these cases, and submit the study cases and results to NERLDC by **20.02.18**.

NERLDC has assessed the state control area wise, state subsystem wise and group of control-area wise TTCs for NER Grid, on behalf of SLDCs of NER. The study results will be presented in the meeting. SLDCs are requested to check the TTC of their control areas as computed by NERLDC and **give comments, if any, by 20.02.18**.

If no comments received from any SLDCs of NER, TTC, ATC & TRM figures of State control area and group of control areas as assessed by NERLDC will be considered as final and may be uploaded on website.

As per discussions in 122nd OCC meeting of NERPC, all SLDCs of NER may host the assessed TTC / ATC / TRM figures on their website for information dissemination.

Members may discuss.

D.5. Implementation of SPS for transfer of 160 MW power to Bangladesh through Tripura-Bangladesh link:

In Special Meeting on SPS, UFR etc. held on 23.06.17, Chief Manager, NERTS, POWERGRID presented the draft scheme to implement the suggested SPS for transfer of 160 MW power to Bangladesh through Tripura-Bangladesh link. The Sub-Committee discussed the suggested schemes in detail and agreed in principle to implement the schemes.

The forum requested NERPC to take up the matter with CEA/CTU/NLDC for implementation at the earliest after vetting in OCC forum.

In 140th OCCM, S.E. (C&O), NERPC informed due to prior engagements of Member Secretary, NERPC the visit to Bangladesh could not be scheduled. Further, he mentioned that methodology of funding of the above tour has to be concurred by MoP. He mentioned that NERPC will discuss with MoP/CTU/NLDC for above visit and intimate in next OCC meeting.

NERPC may please intimate the status.

D.6. SPS mock testing & existing SPS scheme related:

The 138th OCC forum requested NERTS to prepare a draft sequence of operation for each SPS and present in next OCC for ratification. The date for SPS 2 and SPS 3 mock testing will also be finalized in next OCC Meeting.

In 139th OCC meeting, Sr. Engineer NERTS presented the modus-operandi for Mock testing of SPS-2&3. The forum requested OTPC to append the sequences at Palatana GBPP to the modus-operandi and submit at the earliest. The date for mock testing would be decided after that and with prior notice of at least 3 days to all concerned utilities. OTPC has since submitted the sequence of events to be recorded at Palatana GBPP.

The 140th OCC forum opined that NERPC/NERLDC may find some experts from the region to solve this long pending issue and if not, the same may be called from other region. The forum requested OTPC to intimate the details of their action plan for addressing the issues at their end pertaining to the successful operation of SPS-2 & 3 at the earliest.

NERPC vide letter dated. NERPC/SE(O)/OCC/2018 dated 08.02.2018 has requested OTPC to implement the changes as early as possible.

OTPC may please intimate the status.

D.7. Submission of the Annual Load Generation Balance Report (LGBR) for Peak as well as Off-peak scenarios and the Annual outage plan for 2018-19 by 31.10.17 as per IEGC

a) As per IEGC, each SLDC shall submit LGBR for its control area, for peak as well as off-peak scenario, **by 31st October for the next financial year**, to respective RPC Secretariat. The annual plans for managing deficits/surpluses in respective control areas shall clearly be indicated in the LGBR submitted by SLDCs.

b) As per IEGC, all SEBs/STUs, Transmission Licensees, CTU, ISGS, IPPs, MPPs and other generating stations shall provide to the respective RPC Secretariat their proposed outage plan in writing for **the next financial year by 31st October of each year**. These shall contain identification of each generating unit/transmission line/ICT etc., the preferred date for each outage and its duration and where there is flexibility, the earliest start date and latest finishing date.

In 140th OCCM, SE(C&O), NERPC informed that almost all utilities had submitted the relevant data and the final LGBR would be presented in the next OCC meeting. He mentioned that with co-operation from all the utilities the LGBR would be sent to CEA as per scheduled i.e. 31.01.2018.

NERPC may please intimate the status.

D.8. Voltage Deviation Index of PALATANA:

As per presentation given by OTPC, Palatana in 140th OCC meeting, units of Palatana are not absorbing reactive power even in case of 400 kV bus voltage at Palatana is above 420 kV. As per VDI reports issued by NERLDC and uploaded in website, the bus voltage at 400 kV are found to be out of IEGC band (above 420 kV) for more than an hour on regular basis as per **Annexure D.8.**(would be presented in meeting)

Being generator buses they are supposed to control their MVar injection / drawal and maintain the bus voltage within IEGC band at all times.

OTPC may please intimate the results.

D.9. Update on Real Time Energy Assessment for Effective Grid Management:

As decided in 137th. OCC meeting, the matter regarding visit of CDAC to NERLDC was pursued and CDAC representative visited NERLDC on 16.11.2017. Complete details of Meters pertaining to all NER States as sought by CDAC was handed over to them. There are total existing 76 SEMs which would cover computation of drawal by seven States. A list of projected future meters is also given in the statement for integration as and when commissioned.

CDAC would install the AMR system to compute net drawal by each State on every 15 minute time block basis and schedule vs actual as well as computed Deviation charges would be displayed in a server in each SLDC, NERLDC and NERPC secretariat.

As all required data has been handed over, CDAC was advised to start work on the project at the earliest. CDAC need to chalk out an action plan and intimate time bound plan to NERPC so that progress can be monitored in each OCC meeting. It was suggested that work on a particular State at a time may be commenced and completed in time bound target.

In 139th OCCM, CDAC representative stated that they would require the proprietary protocol from the meter manufacturer(s) to proceed further with the Project. DGM(MO), NERLDC explained that as per practice followed in other Regions like NR,

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ER etc., AMR provider, Meter manufacturer and Powergrid sign a tripartite agreement to enable passing of the protocol to AMR provider. A sample of draft agreement in ER (TCS is AMR provider) was provided to CDAC and it was advised that CDAC should initiate process and circulate a draft agreement for the present case. CDAC agreed to do the needful and stated that they would develop protocol converter accordingly.

CDAC was asked not to delay any further and complete the project in quickest possible time.

CDAC has furnished the draft tripartite agreement which is to be signed between CDAC, POWERGRID-NERTS and meter manufacturer(s).

In 140th OCCM, NERPC intimated that the process of signing tripartite agreement between CDAC, Powergrid and L&T was in progress. He requested NERTS to expedite the matter.

NERPC/NERTS may please intimate the status.

D.10. Recording of operational instructions over VOIP in RLDC:

As per 139th OCC discussion establishment of recording system for all real time instructions and conversations thro' VOIP network was supposed to be established within Feb'18. It is very important to establish the recording system at the earliest as all verbal communication/ conversations among RLDCs, SLDCs and stations are getting lost. Recording status at SLDC also may be discussed.

In 140th OCCM, POWERGRID intimated that due to GST issue the issue was delayed but the same now has been resolved and the award will be completed by January, 2018.

POWERGRID may please intimate the latest status.

D.11. Telemetry & Voice Communication Problem:

Telemetry problem: Annexure-D.16 attached in tabular format (updated annexure will be presented in the meeting).

Voice Communication problem: Annexure-D.16 attached in tabular format (updated annexure will be presented in the meeting).

Members may please deliberate for resolution of the issue.

D.12. Utilization of Weather Data by State Utilities

Shri Piyush Goyal, then Union Minister of State (IC) for Power, Coal, New & Renewable Energy and Mines launched the Weather Portal for Power Sector in association with POSOCO and IMD at the meeting of the Forum of Regulators held at New Delhi on 23rd June'17. During a meeting held on 1st November, 2017, IMD has requested all the utilities to give their feedback on the usage of the Weather Portal. The matter was also discussed during 138th OCC Meeting.

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Feedback from SLDC, Mizoram mentioning usefulness has been received but the areas where these are used are not mentioned. The portal is available at <http://amssdelhi.gov.in/NERLDC/MAIN.html>

It is requested to all power utilities to kindly share your feedback on the usage of the Weather Portal. Feedback shall also include the areas where the data of weather portal is used.

In 140th OCCM, NERLDC requested all the utilities to give feedback on the usage of weather portal including requirement of any other further data at the earliest.

NERLDC may please intimate status.

D.13. Connectivity of 132 kV Balipara and 132 kV Sonabil:

As informed by AEGCL earlier, configuration of 132 kV Sonabil Sub-Station was changed due to loading of 220/132 kV, 50 MVA ICT-I at Balipara as 220/132 kV, 50 MVA ICT-II was under outage. Currently, there is no connectivity between 132 kV Balipara and 132 kV Sonabil substations.

Recently, 220/132 kV, 160 MVA ICT-II at Balipara has been commissioned. This newly commissioned 220/132 kV, 160 MVA ICT at Balipara will take care of the over loading of 220/132 kV, 50 MVA ICT at Balipara.

It is requested to AEGCL to restore the earlier configuration of Sonabil and charge 132 kV Balipara – Sonabil line.

In 140th OCCM, AEGCL agreed to restore the earlier configuration of Sonabil and charge 132 kV Balipara – Sonabil line. However, they requested NERPC to write to MD, AEGCL so that the work can be expedited at the earliest.

NERPC vide letter No. NERPC/SE(O)/OCC/2018 dated 08.02.2018 has intimated MD, AEGCL the urgency of the work and requested to expedite the same.

AEGCL may please intimate status.

AGENDA ITEMS FROM NERLDC:

D.14. Element outage / shutdown procedure:

To regularise the OCC approved S/D following procedure is laid down by NLDC for implementation in all the regions.

- I. The Request of outages which are approved in OCC, need to be sent by the indenting agency (ISTS/ISGS/SLDCs) of the transmission asset at least 3 days in advance to respective RLDC by 10:00 Hrs. (For example, if an outage is to be availed on say 10th of the month, the indenting agency would forward such requests to the concerned RLDC on 7th of the month by 10:00 Hrs) This practice is necessary to realize the readiness of the agency. In case the request for transmission element outage is not received within the timeline prescribed above, it will be assumed that the indenting agency is not availing the shutdown.

- II. The proposed outages shall be reviewed on day ahead basis depending upon the system conditions and the outages shall be approved/refused latest by 12:00 hours of D-1 day
- III. RLDC shall be responsible to approve / reject planned outages as per the timeline given in this protocol.

NERLDC may please deliberate.

D.15. Outage of DIMAPUR_PG Substation:

There was incident of fire at Dimapur POWERGRID S/S on 15.01.18 at 1252 hrs and there after all the S/S elements were kept out except 132kV Imphal-Dimapur and 132 kV Dimapur-Dimapur-1. In view of outage of the S/S connectivity, reliability and stability is severely affected. Telemetry and dedicated voice communication of DIMAPUR_PG, SLDC, Nagaland, DOYANG are also out and operations of grid management hampered.

Early restoration of elements & communication system is requested.

POWERGRID may please intimate the status of restoration.

D.16. Restoration procedure of NER 2017:

RESTORATION PROCEDURE of NER for 2017 prepared and uploaded in the NERLDC website on 30.01.2018. The document can be obtained from the following links:

<http://www.nerldc.org/Docs/webupload/Black%20Start%20and%20Restoration%20Procedures%202017.pdf>

All concerned are requested to please go through the restoration procedure 2017.

NERLDC may please deliberate.

D.17. Real-time Scheduling issues:

In 139th OCC meeting scheduling issues were discussed at length. It was requested by forum that all real time schedules are needed to be checked. Apart from uploading all the schedules in NERLDC website, NERLDC is also sending the R1 (published at 2300hrs on D-1) schedule to all SLDCs mail so that all realtime grid managers can go through it and send views if any for error free schedule for next day.

NERLDC may please deliberate.

D.18. Low voltage issue in Tripura, Mizoram & Nagaland Power Systems

In 136th OCCM, Sr. Manager, TSECL opined that AGTCCPP and Monarchak GBPP are not providing reactive power support as per capability curve. Sr. Manager, NEEPCO countered that this is not the case and generators are supplying reactive power according to grid conditions. DGM (MO), NERLDC stated that as a practice, generators are not supposed to provide reactive power support to beneficiaries; rather Tripura should have its own Capacitor banks in place to support the grid. He further opined that generators are rated to operate under normal circumstances at around 0.8/0.9 pf

lag and inject accordingly. The forum requested TSECL to regulate Bangladesh MVAR drawl and conduct meeting at appropriate level in this regard. Member Secretary, NERPC concluded that Tripura should conduct studies and submit DPR of scheme for installation of Capacitor banks at the earliest.

In 137th OCCM, after detailed deliberation the forum requested SLDC Tripura & Mizoram to conduct detailed studies in association with respective distribution utilities at the earliest. Sr. Manager, TSECL informed that currently there are no low voltage problems in Tripura sub-system. After detailed deliberation the forum decided to drop the agenda item and review later on if required.

In the last 3 months, drawl of Bangladesh (South Comilla) from the grid during peak hours was around 140 MW with a power factor of 0.94 (median value). However, Bangladesh may increase their drawl from Mar'18. This can lead to under voltage issue in Tripura Power System in case of contingencies associated with 400 kV Palatana.

Also, due to outage of elements associated with Dimapur (PG), low voltage is observed in Mizoram & Nagaland Power Systems during evening peak. System voltage during peak hours at Aizawl (POWERGRID) and Melriat (POWERGRID) drops to 125 kV every day. NERLDC is taking all available corrective action by opening Bus Reactors at Aizawl, Kumarghat, Imphal but still voltage remains low. Generators available in this area such as THEP, KHEP and LOKTAK are requested to maximise MVAR generation as per capability curve to maintain voltage as per CERC guidelines. Also capacitive compensation at local level may be considered.

It is requested TSECL & P&ED Mizoram to kindly intimate the status of detailed studies in association with respective distribution utilities.

NERLDC may please deliberate.

D.19. Windy Weather Preparedness:

All states of North Eastern Region usually experience heavy windy weather for the period w.e.f March till last of April. As a result of this weather condition, chances of load crashes in the state system as well as tripping of critical grid elements that can lead to Grid Disturbances are high. In March'17, there were 29 Grid Disturbances and 29 load crashes reported while in April'17, number of Grid disturbances increased to 36 and load crashes to 48 Nos.

As a part of this preparedness, NERLDC has given an activity list that is to be followed to all states of NER. Those activities are follows:

- a. Appropriate action for load – generation balance.
- b. Keep frequency, line loading and voltage within prescribed limit.
- c. During High Frequency, generation back down of machines within state power system.
- d. During High Voltage, keep all 'Capacitors' out of service and all 'Bus Reactors' in service. Use 'Line Reactors' as 'Bus Reactors' after discharging the line.
- e. During High Voltage, absorption of 'Reactive Power' by generating unit should be according to 'capability curves'.
- f. Operation of Synchronous Condenser Mode in Hydro machine, if possible.

- g. Maintain alertness on all substations, generating stations and control centers of state power systems

During windy season, most of the line tripping is due to lack of proper vegetation clearance especially due to bamboos coming to the vicinity of line as observed in previous years. So, it is very much necessary to clear all vegetation by transmission utilities to avoid unwanted tripping at the earliest.

As per CERC Order in Petition number 9/SM/2014 dated 14.06.16, in the matter of Investigation of tower collapse and load crash in Northern Region on 30.5.2014, Hon'ble CERC has directed PGCIL to install Anemometer in its all sub-stations to record wind speed.

In 131st OCCM, Member Secretary, NERPC explained the importance of installation of anemometer in POWERGRID substations and requested POWERGRID to furnish status of installation of anemometers in the next OCC meeting.

In 132nd OCCM, DGM (AM), NERTS informed that installation of anemometers is being carried out in SR-1. After satisfactory performance, anemometers will be installed in other regions.

POWERGRID may please intimate the status of installation of anemometers.

NERLDC may please deliberate.

D.20. Automatic Generation Control(AGC)

Primary, Secondary and Tertiary generation reserves are required for frequency control and ensuring reliable operation of the grid, particularly under high Renewable Energy (RE) penetration.

Primary control has been existing in the Indian Electricity Grid Code (IEGC) but its enforcement has been an issue that has been brought several times before the CERC.

Secondary control had been absent in the system so far while tertiary frequency control was introduced only in April 2016 through the Reserves Regulation Ancillary Services or RRAS Regulations of CERC.

CERC has mandated to carry a total of 3623 MW secondary reserves combined in all Regions and **363 MW in NER region**. It was observed that Northern Region (NR) and Western Region (WR) have considerable Un Requisitioned Surplus (URS) on bar for 90% of the time. But, Southern Region (SR), Eastern Region (ER) and **North Eastern Region (NER) have very less URS for most of the time and may not be able to provide the CERC designated Reserves from URS alone.**

The following issues become important when one looks the entire spectrum of frequency control.

1. Ensuring accurate load forecasting and Renewable Energy (RE) forecasting
2. Proper scheduling by each state including indication of reserves
3. Harnessing Reserves within the States
4. Gate Closure
5. Evaluation Area Control Error (ACE) of each control area.

6. Monitoring of primary response from the generating units within the state by SLDCs
7. Periodic monitoring of the data quality needs to be done at the RPC forums
8. Fiber optic communication from Regional Entity power plant to nearest CTU node and there on to RLDCs/NLDC
9. Progressive shifting of AGC services from NLDC to RLDCs'
10. How to ensure adequate reserves for secondary control?
11. Renewable Energy (RE) resources under AGC
12. Encouraging Market Procurement to balance the system in advance

Developments regarding operationalizing of Reserves at the regulatory level from 2015 onwards, details of issues to be discussed and brief note on requirement of data for common transmission system database are attached as **Annexure D.20**. **These items will be discussed in the upcoming NPC meeting.**

NERLDC suggested that BgTPP, NTPC may be considered for implementation of AGC in NER region.

NERLDC may please deliberate.

D.21. List of substations in NER up to 33 kV voltage level under operation and list of all elements connected to NER Grid

NERLDC has compiled the list of substations in NER up to 33 kV levels and list of all elements connected to NER Grid as per data available with NERLDC and also from the data collected from the power utilities of NER.

List of NER substations and list of all elements connected to NER Grid are attached as **Annexure D.21(I) and Annexure D.21(II) respectively**. List of NER substations was circulated among the Power Utilities of NER via email dated 5th Feb'17. List of substations in NER up to 33 kV voltage level is submitted to NERPC for works related PDMS. These documents need to be validated as these may be referred by different utilities for various activities.

Members may please give their comments and finalize the list of substations in under operation NER as well as list of all elements connected to NER Grid.

NERLDC may please deliberate.

D.22. Verification of Transmission Availability Certificate

As per Terms and Conditions of Tariff Regulations of 2014 of CERC, Transmission system availability factor for a calendar month (TAFM) shall be calculated by the respective transmission licensee, got verified by the concerned RLDC and certified by the Member-Secretary, Regional Power Committee of the region concerned, separately for each AC and HVDC transmission system and grouped according to sharing of transmission charges.

For verification of outage report, following details/documents are necessary:

1. Relevant clause no. of Terms and Conditions of Tariff Regulations of 2014 of CERC against each outage which has been claimed as non -attributable.
2. Relay Indications at each end

3. Disturbance Recorder (DR) output, Event Logger (EL) output & FIR (First Information Report)
4. Reason for outage
5. Other relevant documentary evidences (photograph, patrolling report, LA/PLCC counter reading of pre and post event, etc) wherever required.

It is observed in the past few months that some of these details/documents were not submitted along with outage report which makes it difficult to verify same. It is also observed that few outages were missing in the outage report submitted by Transmission Licensees in the last few months. These issues were intimated to respective transmission licensees and NERLDC.

In order to streamline the process, it is suggested that verification outage for a particular month may be done only after submitting

- a. All element outages and
- b. All the relevant documentary evidences along with relevant clause no. against each outage which has been claimed as non-attributable.

NERLDC may please deliberate.

D.23. Procedures of 1st time charging of new non-ISTS elements to nodes of regional entities

As per clause no. 4.1 & 4.2 of CEA (Technical Standards for Connectivity to the Grid) regulations, 2007; a new connection shall not cause any adverse effect on safe operation, integrity and reliability of the grid.

In order to ensure the safe operation, integrity and reliability of the regional grid while charging new non-ISTS elements to nodes of regional entities; it is proposed to follow a procedure by the requester. Draft Procedures suggested by NERLDC for charging of new non-ISTS elements to nodes of regional entities will be presented in the meeting. These procedures were prepared based on the existing *procedure for interconnection of a new transmission element in to Grid belonging to any transmission licensee.*

NERLDC may please deliberate.

D.24. Nomination for Training by POWERTECH

Training regarding Task I & Task II by POWERTECH Labs, Canada is scheduled w.e.f 22nd Feb'18 to 24th Feb'18 at Guwahati.

NERLDC may please deliberate.

D.25. Nomination for SLDC survey

During the 20th FOLD (Forum of Load Despatchers) held on 25th January, 2018 at NERLDC, New Delhi, the agenda on "Updating of the Report on the Survey of LDCs in India" which was a part of 'Pradhan Committee Report'" was discussed in detail. It was deliberated that a team will be formed consisting of members from RLDC and SLDCs which will do survey of each LDC in the region.

Agenda for 141st OCC Meeting to be held on 14th February, 2018

Accordingly, it is kindly requested to nominate 2 (two) officials from SLDC who will coordinate with RLDC for the survey and also could be a part of the team who will do the survey of other SLDCs. It is requested to inform Name, Designation, Contact Number and Email ID of the nominated executives.

SLDCs please nominate 2 (two) officials and inform their details at the earliest.

NERLDC may please deliberate.

METERING RELATED ITEMS

D.26. Procurement of additional 70 Laptops:

Revised Target as intimated by NERTS in 140th. OCC:

i. e-RA : Feb'18

ii. LOA : March'18

iii. Material Dispatch : April'18

OCC expressed serious concern over the delay and stated that there should not be any further delay.

NERTS may intimate status.

D.27. Installation of new L&T SEMs in NER:

Regarding installation of SEMs at Pare and Kameng HEP, NERTS agreed to take necessary action at the earliest.

NERTS also agreed to expedite installation of check meters in ISGS and report the status.

NERTS may intimate status.

D.28. AMR in NER:

NERTS stated the target as below in 140th. OCC meeting:

i. Tendering : Jan'18

ii. Bid opening : Feb'18

iii. LOA : Mar'18

NERTS may intimate status.

D.29. Testing of SEMs at accredited laboratory:

NERTS stated that Tendering would be done in Jan'18.

NERTS may update status.

D.30. Procurement of DCD:

As agreed in 139th. OCC, NERTS was once again advised to initiate necessary action for procurement of DCD.

NERTS agreed to do the needful.

NERTS may intimate status.

D.31. Erratic reading of SEM:

Regarding rectification of meter error at Dullavcherra end of 132 KV Dullavcherra-Dharmanagar feeder, NERTS representative intimated that rectification would be done at the earliest.

NERTS may do the needful.

D.32. Commissioning of RS-485 scheme in all ISGS of NER:

NERTS was advised to initiate action regarding implementation of RS-485 scheme in all ISGS at the earliest in line with point 4 of MOM of SEM meeting. It was agreed that if necessary, L&T personnel should be called for this.

Regarding detailed extensive training by L&T, it was decided that same would be carried out after implementation experience of RS-485 in some Stations and training may also be in one such Stations.

NERTS may intimate status.

AGENDA ITEMS FROM DoP Arunachal Pradesh:

D.33. Integration of new RTUs at RHEP:

GE supplied RTU at RHEP will be provided for accommodating the two new 132 kV extension bays being constructed by us at RHEP in the first-second week of March 2018. Integration of new RTU with existing RTU at RHEP and NERLDC control centre shall be required. Hence special permission may be required through appropriate forum in this regard.

DoP Ar.Pradesh may please deliberate.

D.34. SEM for two 132kV extension bays at RHEP:

SEM meters for commercial accounting will have to be put in place at the two C&R panels of the 132 kV extension bays, for which requisition to concerned authorities will have to be placed through appropriate forum.

DoP Ar.Pradesh may please deliberate.

AGENDA ITEMS FROM OTPC:

D.35. Opening of OTPC GTG-1 Breaker Due to Spurious SPS-3 Signal from Silchar SS:

At 16:34:23 hrs on dated 08/02/2018, Spurious SPS-3 Signal Received from Silchar end and as per SPS-3 Logic GTG-1 Breaker get Open, along with GTG-1 Tie and GTG-2 tie breaker., and Our GT-1 Came into House Load.

On telephonic conversation with Silchar SS, it came under notice that they are performing Battery Bank Switching at Silchar substation at the same Time, which might be resulting of sending SPS-3 Signal.

OTPC may please deliberate.

Any other item:

Date and Venue of next OCC

It is proposed to hold the 142nd OCC meeting of NERPC on second week of March, 2018. The date & exact venue will be intimated in due course.

पावर सिस्टम ऑपरेशन कारपोरेशन लिमिटेड

(भारत सरकार का उद्यम)

POWER SYSTEM OPERATION CORPORATION LIMITED

(A Govt. of India Enterprise)



पंजीकृत एवं केन्द्रीय कार्यालय : प्रथम तल, बी-9, कुतुब इंस्टीट्यूशनल एरिया, कटवारिया सराय, नई दिल्ली-110016
Registered & Corporate Office : 1st Floor, B-9, Qutab Institutional Area, Katwaria Sarai, New Delhi -110016
CIN : U40105DL2009GOI188682, Website : www.posoco.in, E-mail : posococc@posoco.in, Tel.: 011- 41035696, Fax : 011- 26536901

Ref: NLDC/SO/NPC/

Date: 29th January 2018

To
Chief Engineer,
National Power Committee (NPC),
NRPC Building, 18-A,
Shaheed Jeet Singh Marg, Katwaria Sarai,
New Delhi – 110016

Sub: Follow up of the decisions in 7th meeting of NPC

Ref. Letter no. 4/MTGS/NPC/CEA/2018/69-71 dated 17.01.18


Sir,

With reference to your communication above, the agenda on Automatic Generation Control (AGC) for discussion in forums of different Regional Power Committees (RPCs) is enclosed at Annex-I. Formats for data collection from constituents for common transmission system data base is also enclosed at Annex-II. It is felt that as the CERC is already in the process of notifying the Transmission Planning Regulations, data repository in respect of transmission could be covered under this Regulation.

Thanking you,

Yours faithfully,

Encl: as above


(S R Narasimhan) 29/1/2018
General Manager,
System Operation, NLDC

Copy to:

- 1) Chairperson, CEA
- 2) CMD, POSOCO

**Power System Operation Corporation Limited
National Load Despatch Centre
New Delhi**

29th January 2018

Agenda Note on Automatic Generation Control (AGC) for discussion in RPCs

A. Background: Developments regarding Operationalising of Reserves at the regulatory level from 2015 onwards

1. Roadmap to operationalise Reserves in the country was released by Central Electricity Regulatory Commission (CERC) on 13th October 2015. Primary, Secondary and Tertiary controls were identified as essential components for reliable grid operation. Quantum of Reserves were also earmarked by the Hon'ble Commission. Details are available at http://www.cercind.gov.in/2015/orders/SO_11.pdf
2. Central Electricity Regulatory Commission (Ancillary Services Operations) Regulations, 2015 were implemented from 12th April 2016. A detailed half yearly feedback was given by POSOCO to CERC. <https://posoco.in/reports/half-year-feedback-to-cerc/>
3. POSOCO organized a two day brainstorming session on the topic of Spinning Reserves on 19th and 20th Jan 2016 attended by CERC, CEA, POWERGRID (CTU) and POSOCO. Professor Anjan Bose, Regents Professor, Washington State University also attended the same. Reserves were a key agenda in the 16th meeting of Forum Of Load Despatchers (FOLD) held on 2nd March 2016.
4. Based on all consultations, a pilot project in each region was envisaged. NTPC Dadri stg-II (2x490 MW) was selected as the first pilot project for Automatic Generation Control (AGC).
5. Petition no. 79/RC/2017 was filed in the matter of AGC pilot project by POSOCO with CERC in April 2017. <https://posoco.in/download/petition-filed-by-nldc-regarding-agc-pilot-project/?wpdmdl=13543> CERC in its order dated 6th December 2017 approved the Commissioning of the AGC Pilot Project between NLDC and NTPC Dadri Stage-II.
6. For the first time in India, a mock test was successfully conducted on 29th June 2017 by connecting NTPC Dadri stg-II with NLDC through AGC, and the test yielded desired results. During the test, signals were sent directly from NLDC control centre in New Delhi to NTPC Dadri control centre. The generator responded as per the requirement.
7. The Commission observed that development of secondary reserves in the country will lead to grid security and reliability. The Commission also directed that similar pilot projects may be

replicated by NLDC, in at least one other regional grid of the country. CERC Order on the AGC petition was issued on 6th December 2017. http://cercind.gov.in/2017/orders/79_rc.pdf

8. Following the orders of CERC dated 6th Dec 2017, from 1225 hrs of 04th Jan 2018, Dadri stg-II has been taken under remote as a part of Automatic Generation Control pilot project from NLDC. Data is being submitted by NLDC to NRPC in the format on weekly basis based on 2 second data available from the AGC server at NLDC. The entire Northern Region has been considered as a larger balancing area (instead of each State control area) using the Area Control Error of NR.
9. NLDC SCADA upgradation started from October 2017 and is scheduled to be complete by March 2019. AGC integration work involving software modelling, hardware and communication work also has to be done in parallel. NLDC AGC set up is envisaged to be capable of sending and receiving AGC signals to all the Regional Entity generating stations to start with for the first time in India.
10. Report of Expert Group by CERC to review and suggest measures for bringing power system operation closer to National Reference Frequency of 50.0 Hz was released recently. It was recommended that the frequency control continuum chart as given in this report be adopted and included as part of the Indian Electricity Grid Code (IEGC) through an amendment for addendum. The Executive Summary of this report containing the recommendations is enclosed as **Exhibit-I**. The full report is available at http://www.cercind.gov.in/2018/Reports/50%20Hz_Committee1.pdf A brief presentation on this report made in the 20th meeting of FOLD on 25th January 2018 is enclosed at **Exhibit-II**.
11. The Technical Committee of the Forum of Regulators in its 11th Meeting held at Chennai on the 28th March 2017 constituted a Working Group on a region wise basis under the Chairmanship of Member Secretary, RPC for Regional Cooperation with the objective of optimum utilization of RES. The Working Groups in SR, WR and NR have held meetings and an overarching agreement is under discussion in these regions. This cooperation at the Regional level would facilitate implementation of a mechanism for sharing of intra-state reserves.
12. A detailed implementation plan to operationalize the spinning reserves in the country was also submitted to CERC on 14th July 2017 highlighting the issues involved. Secondary Control was recommended to be added as an Ancillary Service. <https://posoco.in/download/detailed-modus-operandi-on-operationalization-of-spinning-reserves/?wpdmdl=13461>

Extracts of the important points of the detailed implementation plan mentioned above are given below:

Secondary Reserves quantum, mandated by CERC, is given in the table below.

Secondary Reserves quantum needed in MW (Region wise)	
NR	800
ER	660
WR	800
SR	1000
NER	363
Total	3623

It is suggested in the detailed implementation plan that the pan India AGC implementation is done in the following manner:

Phase-I

To start with, all the Inter State Generating Stations (ISGS) generators whose tariff is regulated / adopted by CERC are proposed to be made capable of participating in secondary control. The tariff for these generators is already available, there are fewer communication issues, and Ancillary Services Framework is available for settlement and is expected to be dispute free. However, availability of the full quantum of reserves as mandated by CERC may be an issue.

Phase-II

To improve the availability of Reserves, all Regional Entity generating stations scheduled by RLDCs (over and above the Phase-I power stations mentioned above) can be made capable of participating in secondary control. But, Declared Capability (DC) at present is not taken from these generating stations by RLDCs. Some Independent Power Producers (IPPs) have part PPA (Power Purchase Agreement) and part merchant contracts. Tariff for these generators has to be decided and agreed upon apriori for secondary control participation of these generators. DC and Schedule have to be obtained from these generators similar to Central Sector generating stations for reserve estimation. Many of these regional entity generating stations operate in the day ahead energy market and the day ahead prices play a significant role on the status of these generating units as far as availability to the grid at any instant. Low prices in the Day Ahead Market (DAM) on a sustained basis may lead to all these units remaining off the grid. Hence, monitoring & measuring the quantum of reserves may be an issue.

Essential requirements for Secondary Control through AGC:

For the Regional entities to be equipped under Secondary Control, the mandatory requirements include:

- i. Shall bear the cost of secondary control hardware at the plant end including the cost of the fibre optic cable from the plant control room to the nearest communication node.
- ii. Shall share DC and Schedule like ISGS generators on day ahead basis and subsequent revisions with RLDCs.
- iii. Payment for the energy and incentive will be as decided by the Hon'ble Commission.
- iv. The generating units shall have working control systems for turbine, boiler and governor. Governor response plots/graphs of past incidents have to be submitted to RLDC.
- v. Existing wide band communication node within a radius below 30-40 km from the plant to communicate with the nearest RLDC. Distance need not be a binding limitation and can be seen on case to case basis based on the merit.

CERC has mandated to carry a total of 3623 MW secondary reserves combined in all Regions. It was observed that Northern Region (NR) and Western Region (WR) have considerable Un Requisitioned Surplus (URS) on bar for 90% of the time. But, Southern Region (SR), Eastern Region (ER) and North Eastern Region (NER) have very less URS for most time of the and may not be able to provide the CERC designated Reserves from URS alone.

B. Agenda Issues for discussion in the RPC Forum

Primary, secondary and tertiary generation reserves are required for frequency control and ensuring reliable operation of the grid, particularly under high Renewable Energy (RE) penetration. Primary control has been existing in the Indian Electricity Grid Code (IEGC) but its enforcement has been an issue that has been brought several times before the CERC. Secondary control had been absent in the system so far while tertiary frequency control was introduced only in April 2016 through the Reserves Regulation Ancillary Services or RRAS Regulations of CERC. The following issues become important when one looks the entire spectrum of frequency control.

i. Ensuring accurate load forecasting and Renewable Energy (RE) forecasting.

This is the first step towards reliability as generating units need to get committed based on these forecasts. Starting from DISCOM level, the forecasts need to be aggregated for the state at SLDCs level, at RLDCs for the regional level and at NLDC for the All India level.

ii. **Proper scheduling by each state including indication of reserves**

After the above forecast of load and RE generation, the scheduling of conventional generation resources by the states assumes importance. Here, apart from scheduling, the states also need to indicate the amount of hot spinning reserves it is holding. The reserves could be held either within the state or at the ISGS where the state has a share but it should be replenished whenever there is a contingency such as a generating unit tripping within the state. The share of the states in the ISGS is also a form of tertiary reserves as the state reschedules the generation from these ISGS to re-balance the supply-demand within a time frame of 4 time blocks.

Unless such a mechanism is in place, the secondary control would not work as all the reserves would get depleted quickly. This would be evident from the figure below which shows the Declared Capability (DC) of ISGS, DC on bar and the schedules for Dec 2017. The (DC on bar less the schedules) equals the hot spinning reserves. As would be seen, this gets depleted daily during the morning and evening peak hours when states requisition their full entitlement. Under this situation, the state utilities must demonstrate that they have reserves elsewhere within the state.

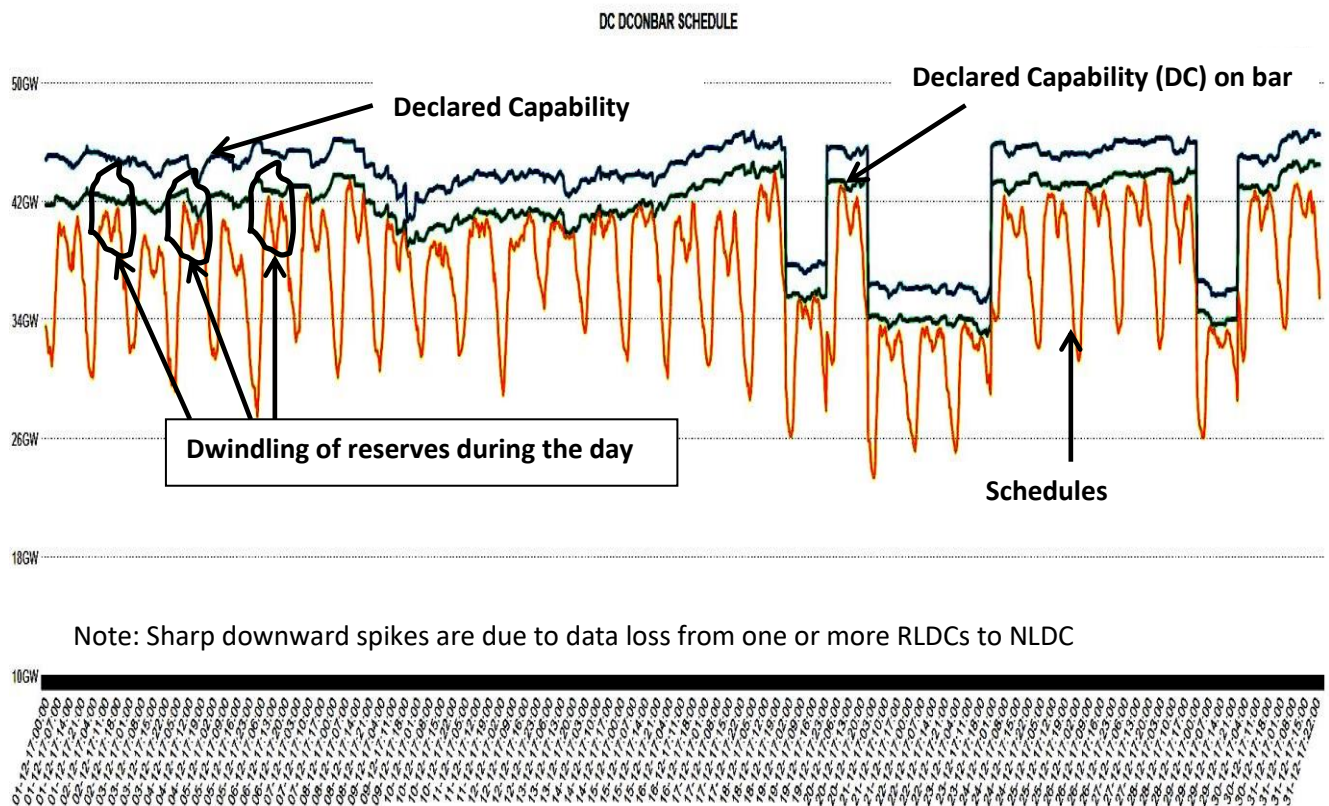


Fig 1: DC, DC on bar and schedules for All India stations in Dec 2017 under Ancillary Services

- iii. **Harnessing Reserves within the States.** The intra-state generation is also capable of providing reserves and these are also being used by the states. However, there is a need for declaration of Declared Capability (DC), DC on bar and the schedules of all such intra-state generation which would help quantify the amount of reserves available inside the state. The information regarding the quantum of reservers could be made available online through the web-portal of the concerned state. This would also help sharing of reserves/regional cooperation between states and could ultimately evolve into a mechanism of joint-despatch between cooperating states.

The Report of the MOP Technical Committee on RE Integration, April 2016 also mentions need for harnessing flexibility in existing fleet of conventional generation as well as Pumped Storage Plants. A regulatory framework for operationalization of reserves at the intra-state level is also required to be implemented. Further, the Committee also recommended that a regulatory framework similar to the ancillary framework by CERC is needed to be implemented in the States for harnessing the intra-state reserves.

- iv. **Gate Closure:** IEGC provides for schedule revisions within 4 time blocks and presently such rescheduling requests keep pouring in continuously in one or the other stations by one of the stakeholders (beneficiary or the generating stations). The generating stations are also changing the Declared Capability as and when required. All this is leading to a situation where the accurate assessment of available reserves by the real time shift operator is just becoming an impossible task. This has particularly been observed in the RRAS despatch where as compared to the UP or DOWN instruction given by NLDC and much lower quantum gets actually implemented. Thus, parallel windows open all the time for rescheduling is leading to this situation.

Internationally, this situation is addressed by the implementation of a “Gate Closure” mechanism where all scheduling changes by stakeholders are barred say about 60 minutes to 30 minutes ahead of the actual time of despatch. It is in this window that the real time shift operator evaluates the system conditions and despatches the firm reserves available at his disposal for balancing the system. Such a “Gate Closure” mechanism is urgently needed in India and the RPC Forum may deliberate the mechanism for implementation of gate closure.

- v. **Evaluate Area Control Error (ACE) of each control area.** Bias maybe taken as equal to Frequency Response Characteristics (FRC) of the state in past ten events. For ACE, high quality measurement of line flows and frequency at 10 seconds or better periodicity at LDCs is a must. Further seamless transfer of schedule data from off-line systems to SCADA must be ensured. RLDCs are already bringing forth the non-availability of real

time data in the RPC forums and this needs to be addressed promptly. ACE, though being used for AGC, is still to find a mention/recognition in the Grid Code and feedback may be given to CERC in this regard.

- vi. **The SLDCs must also monitor the primary response from the generating units within the state** and report to the respective SERCs as directed by CERC vide its order dated 31st July 2017 in petition no 84/MP/2015. The primary droop characteristics of all stations also need to be monitored.
- vii. For AGC high quality measurements are needed for inter-regional tie lines and power plants under AGC. As stated above, **periodic monitoring of the data quality needs to be done at the RPC forums** and chronic problems of non-availability of data addressed promptly so that real time operation is smooth.
- viii. **Fibre optic communication from Regional Entity power plant to nearest CTU node and there on to RLDCs/NLDC** is a must and could be closely monitored through the RPC forums. This is required irrespective of whether we have a regulated system of secondary reserves procurement or a market based one.
- ix. **Shifting AGC services from NLDC to RLDCs' progressively.** The RLDCs' SCADA/EMS system have been recently upgraded over the last three years before AGC was notified through the CERC orders. Hence, AGC considering region as a larger balancing area is being implemented through NLDC, which is a unique experiment as five (5) AGCs are being operated from a single control centre. Further discussion could start on the roadmap as far as AGC is concerned; of shifting it progressively to RLDCs over the next 3-5 years. Considering the fact that SCADA systems at the RLDCs have recently been upgraded, additional hardware/software for implementation of AGC at RLDCs may be considered.
- x. **How to ensure adequate reserves for secondary control?** As seen from Figure 1 above, the spinning reserves viz. DC on bar minus schedules available in real time in ISGS is identified as available hot reserve. This is used for (a) rescheduling/tertiary reserves by states, (b) tertiary frequency control through Reserves Regulation Ancillary Services (RRAS) and (c) envisaged for secondary control through AGC. It is also available for primary control though the IEGC clearly specifies that the schedules should not exceed capacity on bar less Normative Auxiliary Consumption. This ensures that even if the power plant is fully scheduled, the overload capacity and margins in auxiliary consumption is able to provide primary response. SR is already following a philosophy of restricting the maximum schedules so as to ensure availability of margin for primary

reserves. The RPC forum may discuss & suggest ways to ensure adequate availability of reserves for secondary control.

xi. Renewable Energy (RE) resources under AGC: RE sources are generally must-run and the output of RE generator is uninhibited and normally at the maximum possible output. This implies zero margins for up-regulation under AGC, though down-regulation is still possible. There could be a need for RE curtailment either due to the transmission network security issues or an economic curtailment, say when all coal fired units have already been backed down to the minimum 55% levels and there is no scope for further backing down or closing down of units (as peak load has to be catered to later). Under such situations, signals to RE plants could be given from the Load Despatch Centres (LDCs). Most of the new RE procurement bid documents already have a provision for a minimal curtailment levels. Rather than a chaotic system of curtailment in real time, the same could be done more elegantly through AGC (with suitable checks to ensure that RE is backed down last). For facilitating up-regulation through AGC, internationally some margin is being kept in the RE generation. It is suggested that RPCS discuss these issues and make recommendations for the future so that necessary regulatory and policy changes can be brought about.

xii. Encouraging Market Procurement to balance the system in advance: The 24 x 7 market needs to be rejuvenated and the provisions in the Tariff Policy for section 62 generators to utilize the market must be used suitably for this purpose so that states can balance their systems closer to real time. RPC forums may like to deliberate how the situation can be corrected so that better system balance can be achieved ahead of the time of despatch.

X-----X-----X

**Power System Operation Corporation Limited
National Load Despatch Centre
New Delhi-110 016**

25th January 2018

Brief Note on requirement of data for common transmission system database:

For operating the interconnected power grids in a reliable manner, different studies have to be undertaken both in the planning and operating horizon. The studies can be broadly categorized as follows:

- a) Power flow analysis and Contingency analysis : AC power flow analysis is done in the operational horizon for studies related to transfer capability assessment of the control areas, impact assessment of new element charging, outage studies, contingency analysis, etc. The model required for AC power flow analysis is the steady state positive sequence model. Analysis is done using the steady state analysis tool of PSS/E.
- b) Short circuit analysis : Short circuit analysis is done to assess the fault levels of the system buses, impact assessment of balanced and unbalanced faults in the system, protection phenomenon analysis like Single phase auto-reclosure, etc. In addition to the parameters of steady state model, the negative and zero sequence network data are also required for short circuit studies. The short circuit analysis tool of PSSE is used for this analysis.
- c) Transient stability and Small-signal stability analysis : Transient stability analysis is done to assess the impact of time varying phenomenon on the grid and assess the rotor angle stability of the grid. Studies include transfer capability assessment, synchronisation study of new transmission or generation elements, transient disturbances, etc. Small signal stability studies include studies in frequency domain to study the presence of oscillatory modes in the system. The detailed model data of all dynamic components of the power system such as generators, exciters, governors, PSS, excitation limiters, HVDCs, renewable energy generators, etc. are required for these analysis. The transient stability analysis tool of PSSE and eigenvalue analysis tool are used for these analysis.

The data required for modelling in steady state includes data of machines, loads, AC transmission lines, transformers, DC transmission links, fixed shunt, FACTS devices, etc. Accurate modelling is necessary to gain confidence in the simulation done using commercial softwares like PSS/E. For this purpose, it is necessary to get accurate data to correctly

represent the power system components. In absence of accurate power system data, standard data as per CEA's Manual on Transmission Planning criteria, 2013, is used. Development of a common transmission system database will facilitate correction / validation of the power system model developed using standard data.

Accordingly, formats for furnishing data by utilities for accurate modelling in PSS/E software is developed, which can be used as a common format for transmission system database. These are enclosed at **Exhibit-III**.

X-----X-----X

1 Executive Summary

The Central Electricity Regulatory Commission (CERC) vide order dated 27th April 2017 constituted an Expert Group chaired by Shri A S Bakshi, Member, CERC with representatives from CEA, POSOCO and CTU and others concerned with the mandate to suggest further steps required to bring power system operation closer to the national reference frequency of 50 Hz. The Terms of Reference (TOR) of the Committee are as under:

- Review the experience of grid operation in India.
- Review international experience and practices on grid operation including standards/requirement of reference frequency.
- Review the existing operational band of frequency with due regard to the need for safe, secure and reliable operation of the grid.
- Review the principles of Deviation Settlement Mechanism (DSM) rates, including their linkage with frequency, in the light of the emerging market realities.
- Any other matter related to above.

The Committee held three meetings on 9th May, 16th June and 3rd Nov 2017. The 2nd meeting had conference calls with experts from PJM, ENTSOE and Professor Anjan Bose, Washington State University, US. This report covers the first three Terms of Reference pertaining to frequency control in India. The fourth item viz. Deviation Settlement Mechanism (DSM) is covered in a separate report. The Expert Group recommends as under:

1) Frequency Control as a continuum in terms of time horizon

Frequency Control in any power system is basically a continuum starting from seconds to a time period of less than an hour. Beyond this time horizon, the problem is basically one of forecasting, unit commitment, scheduling and despatch. Large imperfections in this area would lead to off-nominal frequency or a large quantum of generation reserves requirement which may be suboptimal. **It is therefore recommended that the frequency control continuum chart as given in this report be adopted and included as part of the Indian Electricity Grid Code (IEGC) through an amendment for addendum.**

2) Reference frequency for the purpose of control

Any control system would need a reference value; in case of frequency control, it would be the target frequency or reference frequency. For the Indian system, the same has to be the nominal frequency of 50.0 Hz. **It is therefore recommended that the reference frequency for the purpose of frequency control is considered as 50.0 Hz, and the same is notified in the IEGC.**

3) **Monitoring inertia of the system and inertial response**

The Expert Group recognizes that interconnection of regional grids and formation of an All India electricity grid with 160 GW peak demand has substantially reduced frequency fluctuations in view of large inertia in the system. However, the inertia would gradually reduce in the coming days with increase in static silicon loads, reduction in rotating mass of conventional machines due to higher penetration of wind and solar generation in the system. With 175 GW RE targeted by 2022, the instantaneous penetration of RE in MW could touch as high as 54%, where inertia would be an issue. This would have an impact on the frequency fall immediately following a large contingency (inertial response) and before primary response effect comes into play. **It is therefore recommended that as a first step, inertia of the system be monitored at the regional and All India level in real time so that a baseline is established and monitored for low net load periods. Simulation studies may also be carried out to assess the inertia and any adverse impact on stability due to low inertia. There is a need for suitable provisions for stipulating minimum inertia in Standards and Code in near future besides provision of synthetic inertia from RE resources.**

4) **Primary control**

Primary control from generating units is mandated as per the Indian Electricity Grid Code (IEGC). However, the IEGC has an historical variant of primary control in the form of Restricted Governor Mode of Operation (RGMO). **The Expert Group recommends that RGMO may be phased out by 1st April 2018 and replaced with 'speed control with droop'. Further, the dead band of +/-0.03 Hz(ripple factor in IEGC) may be gradually phased out as is being done in ERCOT Texas and Europe. This could be a voluntary approach initially. The Expert Group also recommends that the Central Electricity Authority (CEA) may notify the Technical Standards for connectivity to the grid in respect of RE generation at the earliest mandating primary control from RE resources also. Primary control testing would also be done periodically in line with provisions of IEGC for which the performance metrics would be defined in the test procedures by CERC.**

5) **Additional parameters to be notified in IEGC**

Apart from the reference frequency, the Expert Group recommends that the IEGC should also notify the following values:

- a. **Frequency band permissible: 49.90-50.05 Hz currently, which would be further tightened to 49.95-50.05 Hz by 2020 when secondary and tertiary reserves would be operationalized in substantial quantum both at the inter-state and intra-state level besides more frequent market clearing**
- b. **Reference contingency for primary response: 4000 MW UMPP outage**
- c. **Minimum frequency (nadir value) following the above reference contingency: 49.50 Hz**

d. **Quasi steady state frequency value after primary response following the above contingency: 49.80 Hz**

The IEGC would also specify the standards for frequency recording and archival at RLDCs/NLDC level for the purpose of further analysis as mentioned in this report.

6) Frequency Response Characteristics (FRC)

The Expert Group has noted that the RLDCs and NLDC are computing the Frequency Response Characteristics (FRC) of each control area, region and All India basis. There has been a gradual improvement in FRC from 6000 MW/Hz to 9000 MW/Hz over the last two years. Even then this is much lower compared to systems like the Western Interconnection in US (comparable to India in terms of system size) which have recorded FRC of the order of 20000 MW/Hz despite lower obligation as per BAL-003-1 NERC Reliability Standard. **The Expert group recommends as under:**

- a. **RLDCs/NLDC would continue to compute FRC as being done presently. However, the same would also be worked out additionally for All India and region at the 'nadir' frequency (details in the report) so that the impact of inertia can be tracked as indicated in S no 3.**
- b. **While no target FRC is required to be prescribed now, the control area wise FRC and percentage of ideal response would be tracked for each event. A minimum response expected is at least 40% of ideal response (based on international experience). Any violation would be reported to CERC for levy of penalty.**

7) Roadmap for operationalizing reserves

The Expert Group recommends that the roadmap for operationalizing reserves notified by CERC vide order dated 13th October 2015 be implemented at the earliest so that secondary and tertiary reserves as stated in the order are available for frequency control.

8) Secondary Control through Automatic Generation Control (AGC)

As directed by the Commission, POSOCO has already submitted a detailed procedure for implementing secondary control throughout the country through Automatic Generation Control (AGC). A pilot project on AGC with NTPC Dadri Stage-II has been implemented which would be put into operation after approval of the Commission. **The Expert Group recommends that AGC must be implemented throughout the country at the earliest in line with the Commission's recommendation of treating a region as a balancing area. Performance Metrics for such AGC payments may be introduced once sufficient experience is gained through the pilot project. AGC at the intra state level, particularly for large states, can be implemented in line with directions by the Appropriate Commission(s).**

9) **Slow tertiary control through Reserves Regulation Ancillary Service (RRAS)**

Slow tertiary control through Ancillary Services has been implemented pan India since April 2016. **The Expert Group recommends the following:**

- a. **Expanding the ambit of RRAS at the inter-state level and refinements based on experience so far.**
- b. **Introduction of Performance Metrics for mark-up payments for the slow tertiary Ancillary Services.**
- c. **Introduction of slow tertiary Ancillary Services at the intra state level through regulations by Appropriate Commission. This would necessitate implementing the Scheduling, Accounting, Metering and Settlement of Transactions (SAMAST) at the intra state level.**

10) **Fast tertiary control at the Inter State level**

The slow tertiary RRAS at the inter state level leads to a situation where the impact is felt only after 20-30 minutes. The hydro power stations have not been utilized for RRAS so far. **The Expert Group recommends that fast tertiary services through RRAS using hydro could be introduced suitably at the inter state level to start with.**

11) **Monitoring of Area Control Error (ACE)**

It is expected that with all the above steps in place, frequency is expected to be within the IEGC mandated band for nearly 100% of the time. Nevertheless, as stated earlier, for a time horizon beyond one hour, forecasting and scheduling becomes important and any large scale errors here can impact frequency control. Hence monitoring each state control area performance is also important. **The Expert Group recommends as under:**

- a. **Each state control area, region and the neighbouring countries would work out the Area Control Error (ACE), display, monitor and archive the same. For the purpose of ACE calculation, the bias could be set as 4% of Area load per Hz which can be refined over time. The inter-state and inter-regional tie line values as well as frequency measurements should be treated as Class A telemetry values and updated at a faster rate than ten (10) seconds at SLDCs/RLDCs/NLDC.**
- b. **The ACE, worked out as above, should cross zero value and change sign at least once every hour to start with which would be narrowed down to half an hour. Persistent violation of this condition would render the utility liable for penalties.**
- c. **The 15-minute deviations from the schedule as worked out through Special Energy Meter (SEM) data and schedules would be closely monitored for all time blocks where average frequency is below 49.95 Hz and above 50.05 Hz. On a monthly basis, the 90th percentile value of overdrawals below 49.95 Hz and underdrawals above 50.05 Hz**

would be monitored. This should not exceed 150 MW. Any violation could render the utility liable for penalties.

12) Time Error

Time error is the difference between the time reported by a synchronous clock, compared to the time reported by a reference synchronous clock. This error signifies the deviation of average frequency from reference frequency. Time error on daily basis (0000-2400 hours) would also be recorded at NLDC level. Standards for cumulative time error would be notified separately by CERC, at an appropriate time based on the experience gained and considering cross border interconnections.

Report
of
Expert Group to review and suggest measures
for
bringing power system operation closer
to
National Reference Frequency
(Volume-I)



केन्द्रीय विद्युत विनियामक आयोग
CENTRAL ELECTRICITY REGULATORY COMMISSION



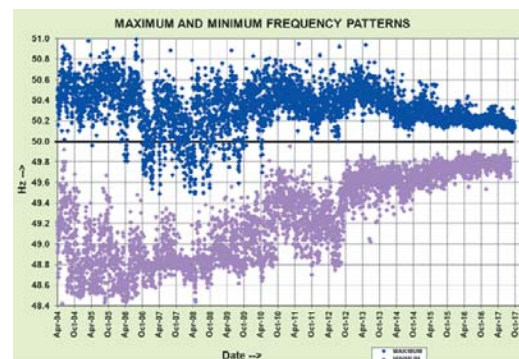
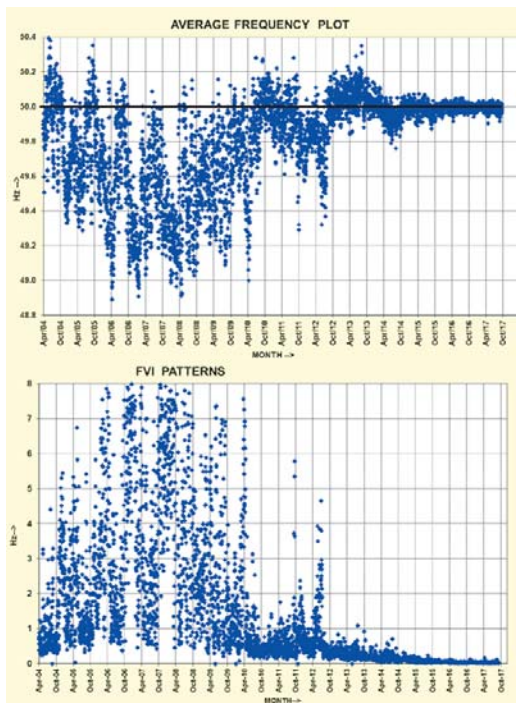
Background

- National reference frequency declared as 50 Hz
 - CERC meeting dated 23rd March 2017
- Constitution of high level expert group
 - CERC Order dated 27th March 2017
 - Representation from CEA, POSOCO, CTU and CERC
- TOR of the expert group
 - Review the experience of grid operation in India.
 - Review international experience and practices on grid operation including standards/requirement of reference frequency.
 - Review the existing operational band of frequency with due regard to the need for safe, secure and reliable operation of the grid.
 - Review the principles of Deviation Settlement Mechanism (DSM) rates, including their linkage with frequency, in the light of the emerging market realities.
 - Any other matter related to above.

Expert Group Meetings

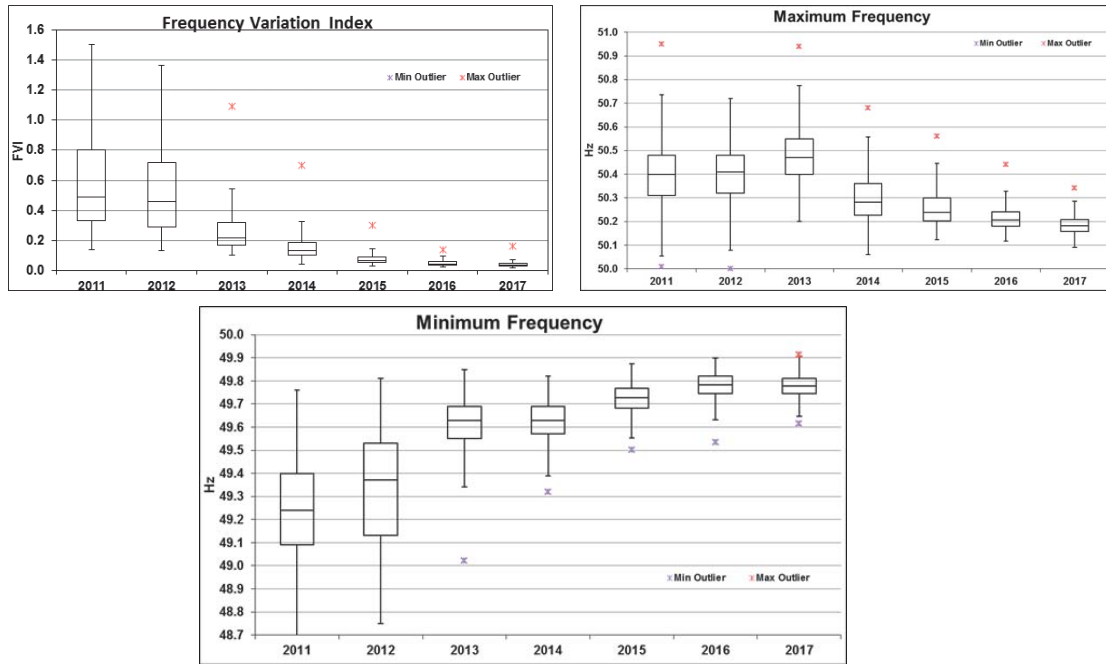
- 1st Meeting: 9th May 2017, CERC
 - 50Hz may be recognized as National Reference Frequency for power system operation in India.
 - Gradually phase out the Restricted Governor Mode of Operation (RGMO) by 1st April 2018
 - Invitation to academia and international experts
- 2nd Meeting : 16th June 2017, NRLDC
 - Discussion with International experts from PJM and ENTSOE
 - Discussion with Prof Anjan Bose, Washington State University
- 3rd Meeting : 19th July 2017, CERC
 - Discussion on issues related to DSM Charges and Ancillary Services
- 4th Meeting : 03rd November 2017, CERC
 - Review of draft report

Experience of grid operation in the context of frequency control

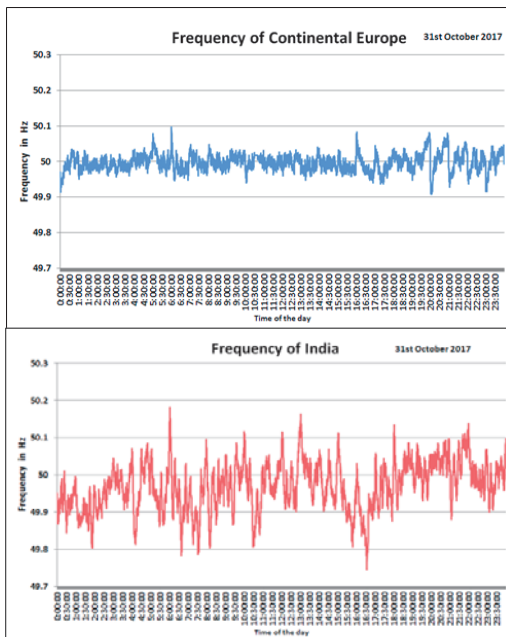


- UFLS relays have not operated in day to day normal operations.
(Last Operated :24.05.2015; SR Separation)
- Df/dt relays have operated only in case of a major contingency
(Last Operated : 12.03.2014; UMPP 4000 MW)

Experience of grid operation in the context of frequency control



Comparison of typical Indian frequency with other large power systems



S no	Description	Values for	
		CE	India
1	Standard Deviation (Hz)	0.019	0.042
2	Frequency Variation Index (FVI) in Hz	0.0036	0.020
3	Instantaneous maximum frequency (Hz)	50.060	50.154
4	Instantaneous minimum frequency (Hz)	49.916	49.885
5	15-minute maximum average frequency (Hz)	50.033	50.065
6	15-minute minimum average frequency (Hz)	49.965	49.952
7	% of time frequency remained within 49.90-50.05 Hz	99.61	81.08
8	% of time frequency below 49.90 Hz	0.00	0.06
9	% of time frequency above 50.05 Hz	0.39	18.86
10	Average time frequency remains below 49.97 Hz for every excursion (mm:ss)	00:38	02:10
11	Average time frequency remains above 50.03 Hz for every excursion (mm:ss)	00:33	02:48
12	No of excursions above 50.03 Hz	112	177
13	No of excursions below 49.97 Hz	139	94

CE : Continental Europe

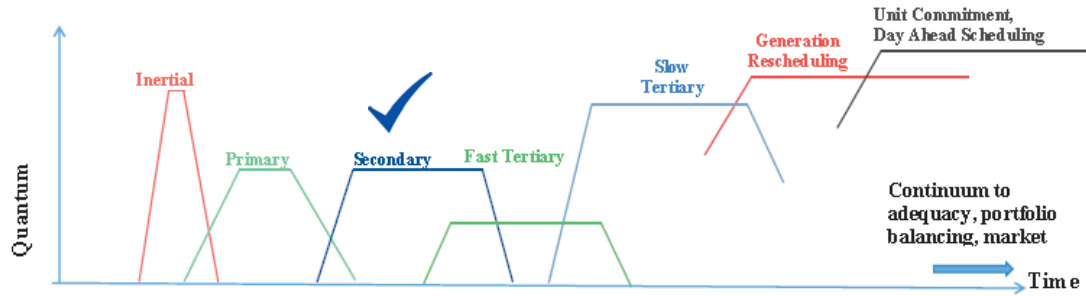
International scenario in respect of frequency control

- North America
 - Reliability Standards
 - Primary response is a mandatory service
 - BAL-003-1 : Interconnection Frequency Response Obligation
 - CAISO proposal for Primary Response Payment
 - Approved by FERC in Feb 16
 - Secondary Control
 - BAL-003-1.1, CPS1
 - FERC Order 755: Pay as per performance
 - Contingency reserve or supplemental reserve
 - Procured by ISO through market

International scenario in respect of frequency control

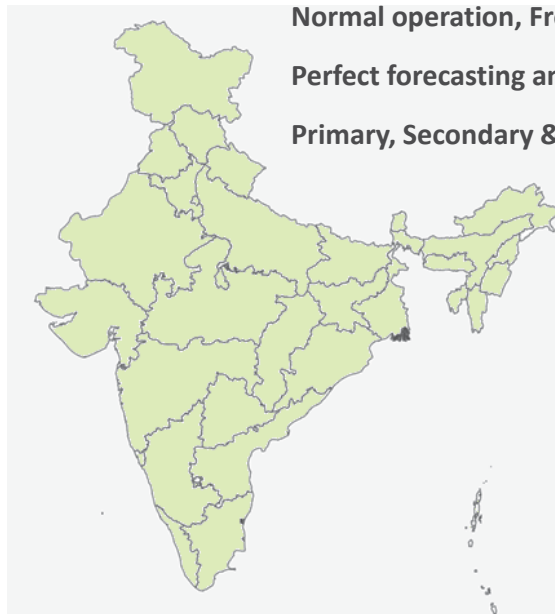
- Continental Europe
 - ENTSOE Network Code on Load Frequency Control and Reserves
 - Frequency Band : 49.95-50.05 Hz
 - Instantaneous Max Dip : 49.2 Hz
 - Recovery through primary response : 49.8 Hz
 - Frequency to be restored within band in 15 minutes
 - Draft European Union (EU) guideline on electricity transmission system operation
 - Frequency outside band : 15000 minutes per year
 - Reserves
 - Frequency Containment Reserve (FCR) similar to primary control
 - Frequency restoration Reserves (FRR) similar to secondary control through AGC
 - Restoration Reserves (RR) to replace FRR similar to tertiary control.

Frequency Control Continuum in India



Response Attribute	Inertial	Primary	Secondary	Fast Tertiary	Slow Tertiary	Generation Rescheduling/Market	Unit Commitment
Time	First few sec s	Few sec - 5 min	30 s - 15 min	5 - 30 min	> 15 - 60 min	> 60 min	Hours/ day-ahead
Quantum	~ 10000 MW/Hz	~ 4000 MW	~ 4000 MW	~ 1000 MW	~ 8000-9000 MW	Load Generation Balance	Load Generation Balance
Local / LDC	Local	Local	NLDC / RLDC	NLDC	NLDC / SLDC	RLDC / SLDC	RLDC / SLDC
Manual / Automatic	Automatic	Automatic	Automatic	Manual	Manual	Manual	Manual
Centralized / Decentralized	Decentralized	Decentralized	Centralized	Centralized	Centralized/ Decentralized	Decentralized	Decentralized
Code / Order	IEGC / CEA Standard (?)	IEGC / CEA Standard	Roadmap on Reserves	Ancillary Regulations	Ancillary Regulations	IEGC	IEGC
Paid / Mandated	Mandated	Mandated	Paid	Paid	Paid	Paid	Paid
Regulated / Market	Regulated	Regulated	Regulated	Regulated	Regulated / Market	Regulated / Market	Regulated / Market
Implementation	Existing	Partly Existing	Pilot	Yet to start	Existing	Existing	Existing

Normal Operation



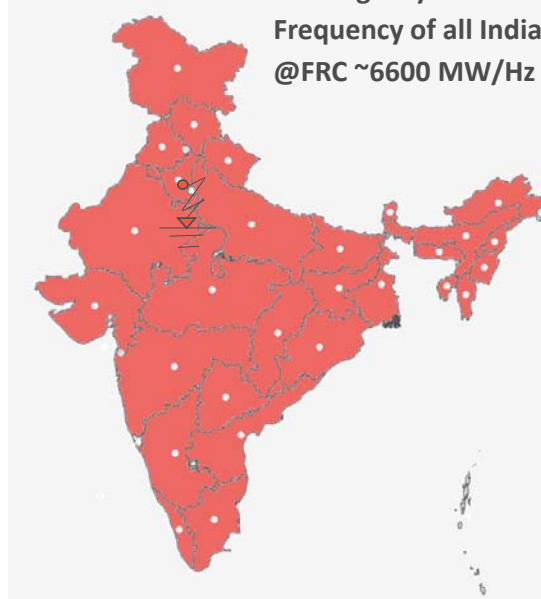
Normal operation, Frequency 50 Hz.

Perfect forecasting and scheduling

Primary, Secondary & Tertiary Reserves in place.

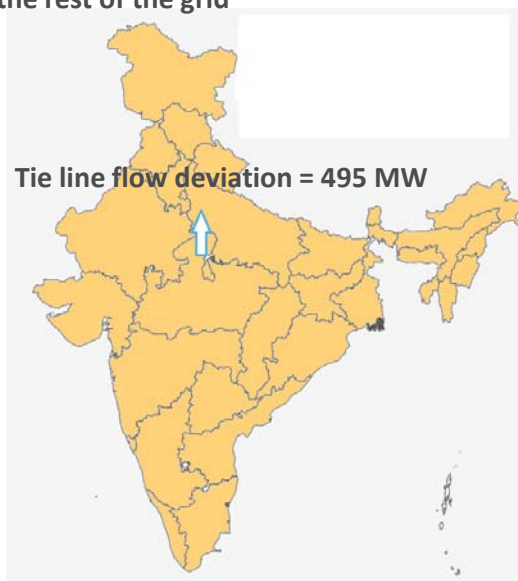
Contingency

Contingency of loss of 660 MW unit in NR.
Frequency of all India drops to 49.9 Hz.
@FRC ~6600 MW/Hz



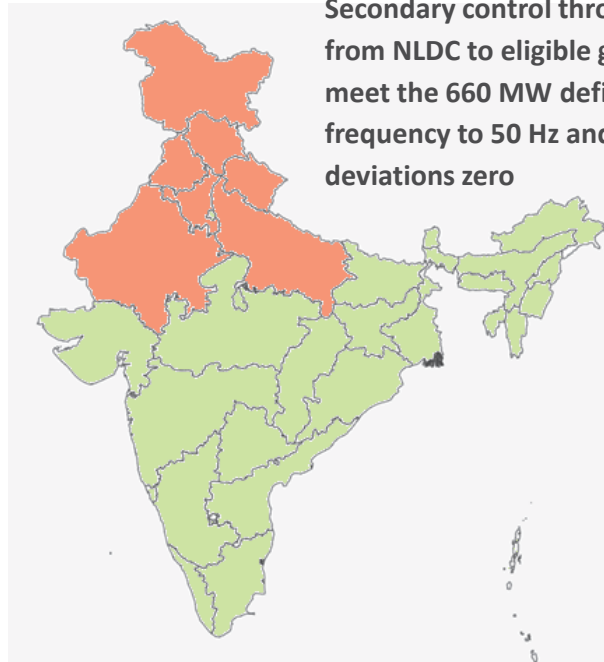
Primary Response

Primary response obtained from all the generators pan India
and load response due to frequency fall. NR imports extra 495
MW from the rest of the grid



All generators throughout the country exhibit solidarity through primary response!!

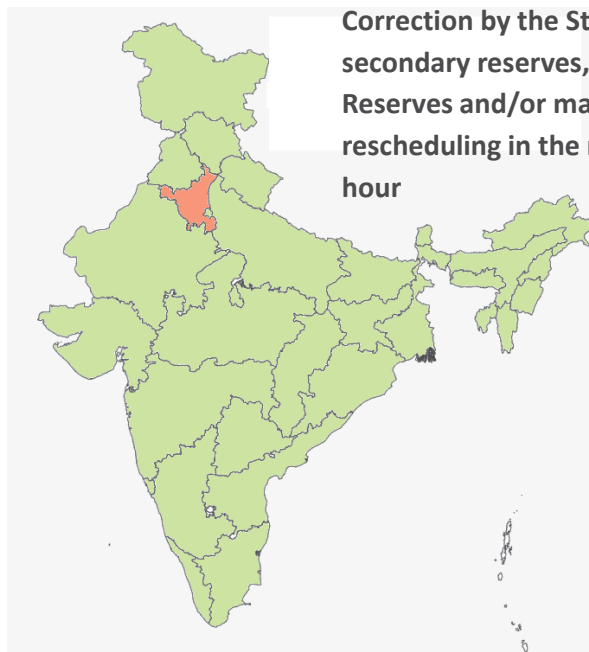
Secondary Control



Secondary control through AGC signals sent from NLDC to eligible generators in NR to meet the 660 MW deficit. This will restore frequency to 50 Hz and make tie line deviations zero

Generators in the affected region rise to the occasion and say thanks to all the countrymen!

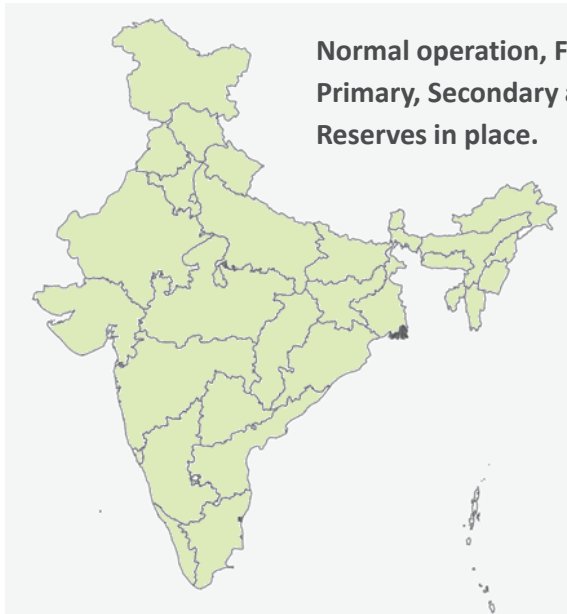
Tertiary Control



Correction by the State. To restore secondary reserves, State has to use Tertiary Reserves and/or make generation rescheduling in the next half an hour to 1 hour

The affected state has time to recoup its strength and say a big thank you!

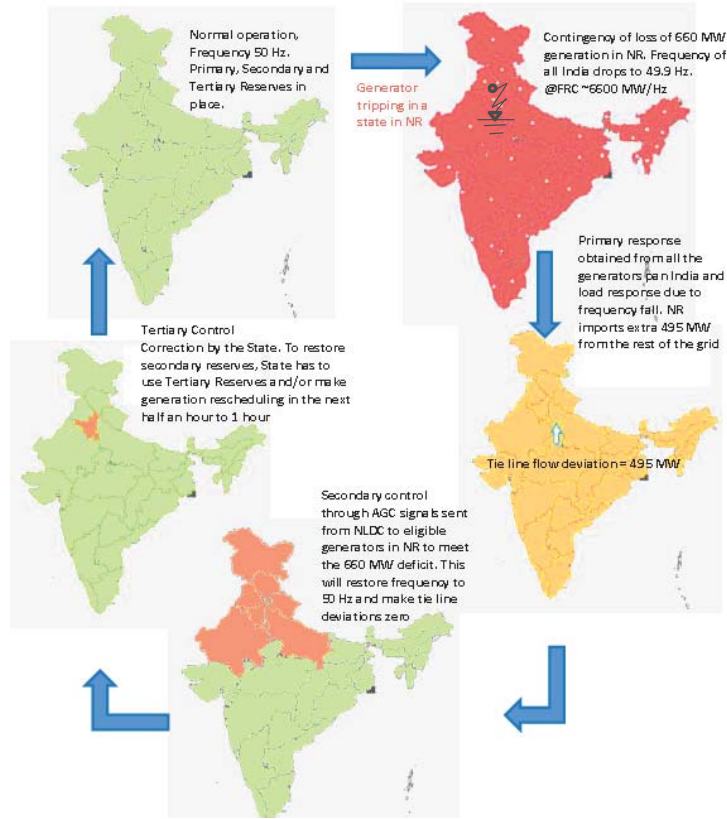
Normal Operation



Normal operation, Frequency 50 Hz.
Primary, Secondary and Tertiary
Reserves in place.

Grid operation goes on smoothly with the assurance that help is at hand during any crisis!

All in a day's play repeated again and again



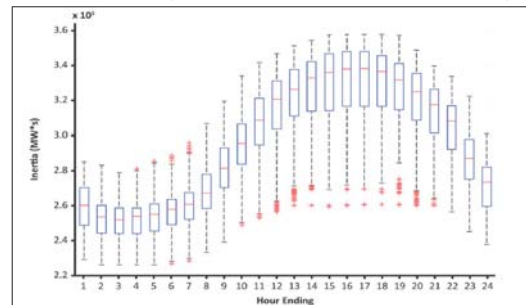
Inertia monitoring

- Increased penetration of RE : Impact on System Inertia
- Higher Inertia older machines (4 MW-sec/MVA)
- Lower Inertia: Newer Machines (2.5-3.0 MW-sec/MVA)
- Impacts System Stability
- Need to monitor Inertia in real time
- Unit Commitment considering minimum inertia requirement

ERCOT dashboard to monitor the real time inertia

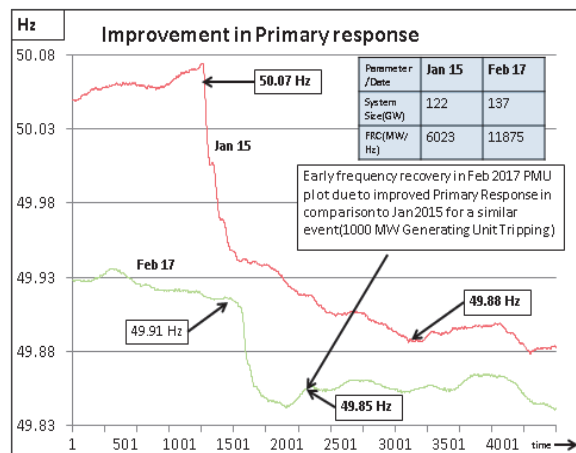
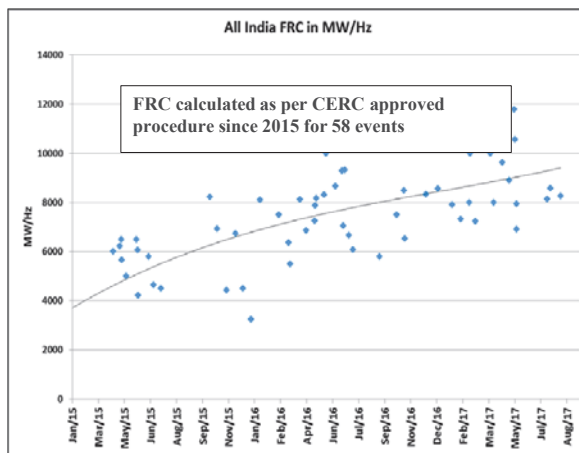


ERCOT inertia by the hour from 1st June to 15th July 2016

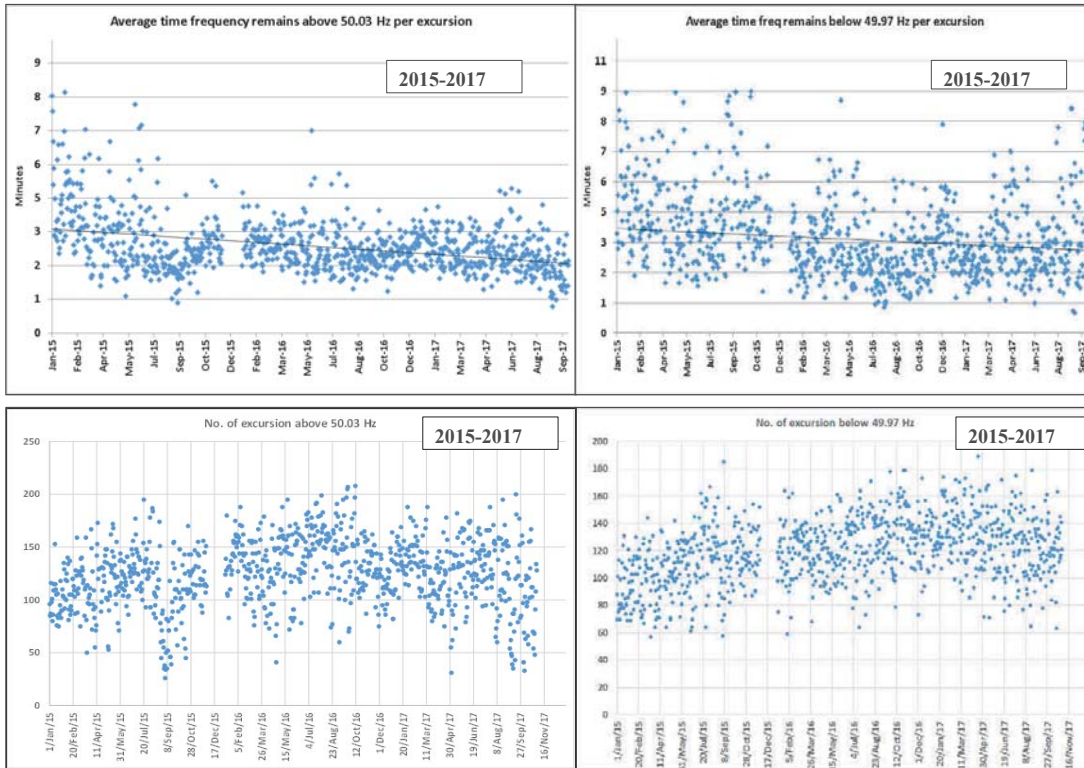


Primary frequency response in India

- Frequency Response Characteristics (FRC) calculation by RLDCs/NLDC as per CERC procedure



Review of primary frequency response in India



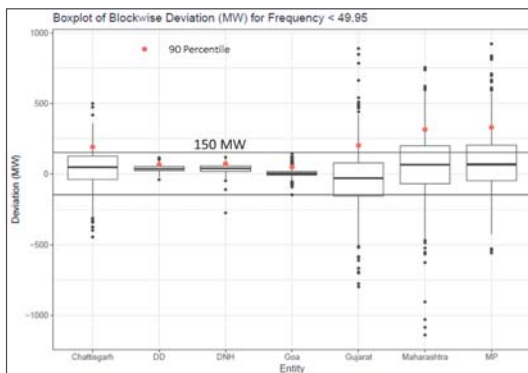
Typical Calculation for Frequency Response in Indian Context

Item	Number
Size of Largest Generating Station	4000 MW
Quasi Steady State Frequency for loss of largest generating station	49.8 Hz
Ideal Response	$=4000/(50-49.8)$ $=20000 \text{ MW/Hz}$
Desired Load Response (4% of All India Demand)	$=0.04 * 140000$ $=5600 \text{ MW/Hz}$
Desired Response from Generators	$= 20000 - 5600$ $= 14400 \text{ MW/Hz}$

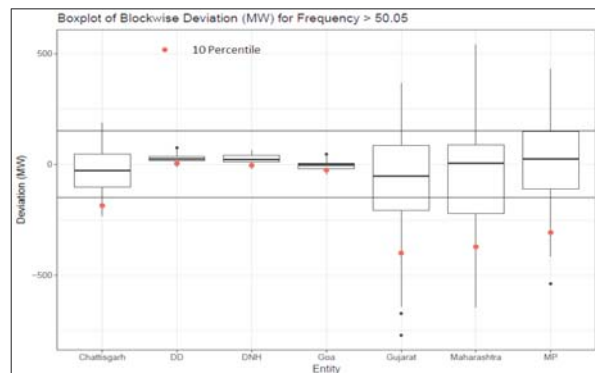
Review of secondary frequency control

- AGC Pilot Project in association with NTPC Dadri
 - Mock Test on 29th June 2017
 - CERC Order on AGC pilot project dated 06th Dec 2017
 - One pilot in each region
 - Under Continuous Operation since 04th Jan 2018
- AGC Pilot for Hydro already under consideration by KPCL
- AGC pilot for Solar / Wind to be undertaken
- AGC feature included in NLDC upgradation project
- Detailed procedure to operationalize reserves
 - submitted to CERC in July 2017

Review of tertiary frequency control and Control Area Performance



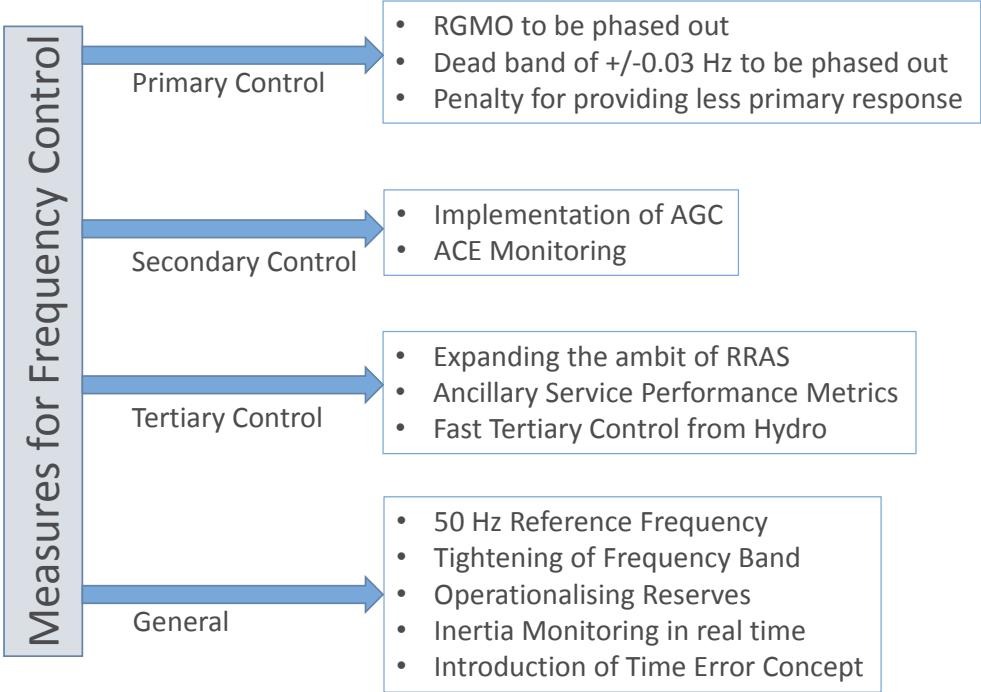
Deviation from the schedule by WR states in September 2017 below 49.95 Hz



Deviation from the schedule by WR states in September 2017 above 50.05 Hz

- States like Gujarat, Chhattisgarh, Maharashtra and MP exceeded the 150 MW limit for more than 10% of the time
- Need for performance metrics for assessing a control area's performance
- ACE should cross zero value and change sign at least once every hour
- Penalty for persistent violation

Recommendations-Summary



Thank You !

Recommendations

- **Frequency control continuum chart**
 - As given in the report to be added in IEGC
- **50 Hz Reference Frequency**
 - To be notified in IEGC
- **Inertia Monitoring in real time**
 - All India & Regional Basis
 - Provisions for minimum inertia in Standards and Code
- **Primary Control**
 - RGMO to be phased by 1st April 2018
 - Dead band of +/-0.03 Hz to be gradually phased out
 - Testing of Primary Response
 - Notification of CEA Technical Standards for connectivity to the grid in respect of RE generation at the earliest

Recommendations

- **Additional parameters to be notified in IEGC**
 - Tightening of Frequency Band to 49.95-50.05 Hz by 2020
 - Reference contingency for primary response: 4000 MW UMPP outage
 - Minimum frequency (nadir value) following the above reference contingency: 49.50 Hz
 - Quasi steady state frequency value after primary response following the above contingency: 49.80 Hz
- **Frequency Response Characteristics (FRC)**
 - RLDCs/NLDC would continue to compute FRC as being done presently
 - All India and Regional FRC computation at the 'nadir' frequency
 - Reporting to CERC for levy of penalty if actual response is less than 40% of ideal response

Recommendations

- **Roadmap for operationalizing reserves**
 - Roadmap for operationalizing reserves notified by CERC vide order dated 13th October 2015 be implemented at the earliest.
- **Secondary Control through Automatic Generation Control**
 - AGC must be implemented throughout the country
 - Performance Metrics for such AGC payments may be introduced once sufficient experience is gained
 - AGC at the intra state level to be also implemented
- **Slow tertiary control through Reserves Regulation Ancillary Service (RRAS)**
 - Expanding the ambit of RRAS at the inter-state level
 - Introduction of Performance Metrics for mark-up payments for the slow tertiary Ancillary Services
 - Introduction of slow tertiary Ancillary Services at the intra-state level

Recommendations

- **Fast tertiary control at the Inter State level**
 - Fast tertiary services through RRAS using hydro could be introduced
- **Monitoring of Area Control Error (ACE)**
 - Display, Monitoring and Archival of ACE
 - ACE to change sign, once every hour
- **Time Error**
 - Standards for cumulative time error to be notified separately by CERC

Common data for modelling

A. Loads

Bus Name	
Voltage level	
Pload(MW)	
Qload(MVAR)	
IPLoad(MW)	
IQLoad(MVAR)	
YPLoad(MW)	
YQLoad (MVAR)	
Distributed Gen (MW)	
Distributed Gen (MVAR)	
Substation Bus scheme	
Substation Co-ordinates	
a) Latitude	
b) Longitude	
Owner	
Switchgear ampere Capacity	

B. Transmission Lines

From Bus Name	
To Bus Name	
Circuit No	
Conductor Type	
Conductor Design Temperature (°c)	
Ampacity (in Amp)	
Line R (pu)	
Line X (pu)	
Charging B (pu)	
Line G From (pu)	
Line B From (pu)	
From Reactor Switchable (Yes / No)	
Line G To (pu)	
Line B To (pu)	
To Reactor Switchable (Yes / No)	
R-Zero (pu)	
X-Zero (pu)	
B-Zero (pu)	
Line length (km)	
Owner	
Fixed Series Compensation (Xc)	

C. Fixed shunt

Bus Name	
Voltage level (kv)	
G-shunt (MW)	
B-shunt (MVAR)	
G-zero (MW)	
B-zero (MVAR)	

D. Two winding transformers

From Bus Name	
To Bus Name	
Circuit No	
Rating (MVA)	
Vector Group	
Specified R (pu)	
Specified X (pu)	
Controlled Bus	
No. of Tap Positions	
Nominal Tap	
Tap Step (pu)	
Magnetising G	
Magnetising B	
Winding MVA Base	
Rmax (pu)	
Rmin (pu)	
Vmax (pu)	
Vmin (pu)	

E. Machines

Bus Name	
Voltage level	
Vscheduled (in kV)	
Pgen (MW)	
Pmax (MW)	
Pmin (MW)	
Qmax (MW)	
Qmin (MW)	
MVABase (MVA)	
Turbine MVA Rating (MVA)	
Fuel Type	
Rsource (pu)	
Xsource (pu)	
Rtran (pu)	
Xtran (pu)	
GSU capacity (in MVA)	
GSU Voltage rating	
GSU No. of taps	
GSU Nominal tap	
GSU Tap step	
GSU Current Tap	
Subtransient X (pu)	
Transient X (pu)	
R-Negative (pu)	
X-Negative (pu)	
R-Zero (pu)	
X-Zero (pu)	
Renewable generator (Yes / No)	
Renewable generator type (Type-3/Type-2/Type-3/Type-4)	
Renewable generator Power Factor	
Capability Curve (Please Enclose)	
V Curve (Please Enclose)	
Open Circuit Characteristic (Please Enclose)	
Short Circuit Characteristic (Please Enclose)	

F. Switched shunt

Bus Name	
Control Mode	
Adjustment method	
Vhi (pu)	
Vlo (pu)	
RMPCT (%)	
Binit (Mvar)	
Blk 3 Steps	
Blk 3 Bstep (Mvar)	
Blk 2 Steps	
Blk 2 Bstep (Mvar)	
Blk 3 Steps	
Blk 3 Bstep (Mvar)	
Blk 4 Steps	
Blk 4 Bstep (Mvar)	
Blk 5 Steps	
Blk 5 Bstep (Mvar)	
Blk 6 Steps	
Blk 6 Bstep (Mvar)	
Blk 7 Steps	
Blk 7 Bstep (Mvar)	
Blk 8 Steps	
Blk 8 Bstep (Mvar)	
Blk 3 Bzero (Mvar)	
Blk 2 Bzero (Mvar)	
Blk 3 Bzero (Mvar)	
Blk 4 Bzero (Mvar)	
Blk 5 Bzero (Mvar)	
Blk 6 Bzero (Mvar)	
Blk 7 Bzero (Mvar)	
Blk 8 Bzero (Mvar)	

G. Three Winding Transformers Data

Transformer Vector group	
Positive sequence resistance between HV/LV1	
Positive sequence reactance between HV/LV1	
Zero sequence resistance between HV/LV1	
Zero sequence reactance between HV/LV1	
Positive sequence resistance between HV/LV2	
Positive sequence reactance between HV/LV2	
Zero sequence resistance between HV/LV2	
Zero sequence reactance between HV/LV2	
Positive sequence resistance between LV1/LV2	
Positive sequence reactance between LV1/LV2	
Zero sequence resistance between LV1/LV2	
Zero sequence reactance between LV1/LV2	
Positive sequence resistance between HV/(LV1+LV2)	
Positive sequence reactance between HV/(LV1+LV2)	
Zero sequence resistance between HV/(LV1+LV2)	
Zero sequence reactance between HV/(LV1+LV2)	

H. Two terminal DC

Line:	
Inverter end	
Rectifier end	
Control mode (Power/ current)	
Rdc (ohms)	
Setval (Amp or MW)	
Vsched (kV)	
DCVmin (kV)	
Rated Capacity (in MW)	
Converters (Rectifier / inverter):	
Max Firing Angle (deg)	
Min Firing Angle (deg)	
Bridges in Series	
Primary Base Voltage (kV)	
Commutating Resistance (ohms)	
Commutating Reactance (ohms)	
Trans Ratio (pu)	
Tap Setting (pu)	
Max Tap Setting (pu)	
Min Tap Setting (pu)	
Tap Step (pu)	
Reactance of CCC (ohms)	

I. Multi terminal DC

Line:		Multi-terminal link details:	
Control Mode		DC Bus Name	
Number of Converters		ConverterBus	
Number of DC Bus		RG (ohms)	
Number of DC Link		DC Bus Second	
Vcmode (kV)			
+ pole inverter AC bus		DC Link	
- pole inverter AC bus		From DC Name	
Converter:		To DC Name	
ConverterNumber		Id	
Bus Name		Rdc (ohms)	
Pole (Pos/Neg)		LDC-Mh	
Min (deg)			
Max (deg)			
Setval (deg)			
Nb			
Ebase (kV)			
Rc (ohms)			
Xc (ohms)			
Transformer Ratio (pu)			
Tap (pu)			
Tap Min (pu)			
Tap Max (pu)			
Tap Step (pu)			
Margin (pu)			
Participation factor			

GENERATOR MODELS

1.19 GENROU

Round Rotor Generator Model (Quadratic Saturation)

This model is located at system bus #_____ IBUS,

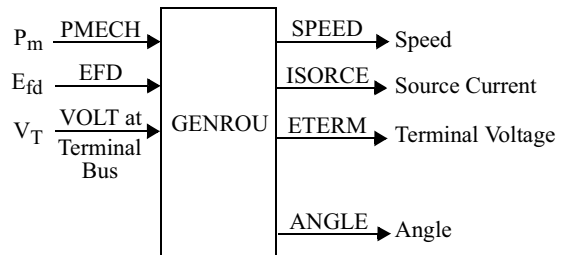
Machine identifier #_____ ID,

This model uses CONs starting with #_____ J,

and STATEs starting with #_____ K.

The machine MVA is _____ for each of _____ units = _____ MBASE.

ZSORCE for this machine is _____ + j _____ on the above MBASE



CONs	#	Value	Description
J			$T'_{do} (>0)$ (sec)
J+1			$T''_{do} (>0)$ (sec)
J+2			$T'_{qo} (>0)$ (sec)
J+3			$T''_{qo} (>0)$ (sec)
J+4			H, Inertia
J+5			D, Speed damping
J+6			X_d
J+7			X_q
J+8			X'_d
J+9			X'_q
J+10			$X''_d = X''_q$
J+11			X_l
J+12			S(1.0)
J+13			S(1.2)

Note: X_d , X_q , X'_d , X'_q , X''_d , X''_q , X_l , H, and D are in pu, machine MVA base.

X''_q must be equal to X''_d .

STATES	#	Description
K		E'_q
K+1		E'_d
K+2		ψ_{kd}
K+3		ψ_{kq}
K+4		Δ speed (pu)
K+5		Angle (radians)

IBUS, 'GENROU', ID, CON(J) to CON(J+13) /

1.21 GENSAL

Salient Pole Generator Model (Quadratic Saturation on d-Axis)

This model is located at system bus # _____ IBUS,

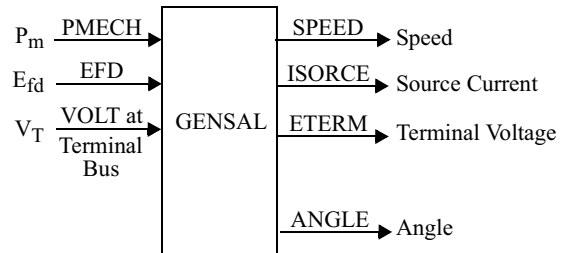
Machine identifier # _____ ID,

This model uses CONs starting with # _____ J,

and STATEs starting with # _____ K.

The machine MVA is _____ for each of units = _____ MBASE.

ZSORCE for this machine is _____ + j _____ on the above MBASE.



CONs	#	Value	Description
J			T'_{do} (>0) (sec)
J+1			T''_{do} (>0) (sec)
J+2			T''_{qo} (>0) (sec)
J+3			H, Inertia
J+4			D, Speed damping
J+5			X_d
J+6			X_q
J+7			X'_d
J+8			$X''_d = X''_q$
J+9			X_l
J+10			S(1.0)
J+11			S(1.2)

Note: X_d , X_q , X'_d , X''_d , X''_q , X_l , H, and D are in pu, machine MVA base.

X''_q must be equal to X''_d .

STATEs	#	Description
K		E'_q
K+1		ψ_{kd}
K+2		ψ''_q
K+3		Δ speed (pu)
K+4		Angle (radians)

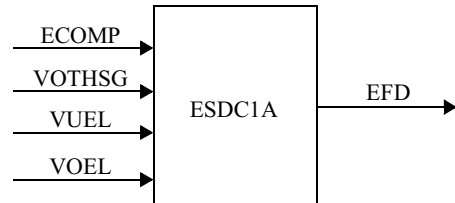
IBUS, 'GENSAL', ID, CON(J) to CON(J+11) /

EXCITER MODELS

6.16 ESDC1A

IEEE Type DC1A Excitation System

This model is located at system bus # _____ IBUS,
Machine identifier # _____ ID,
This model uses CONs starting with # _____ J,
and STATEs starting with # _____ K,
and VAR # _____ L.



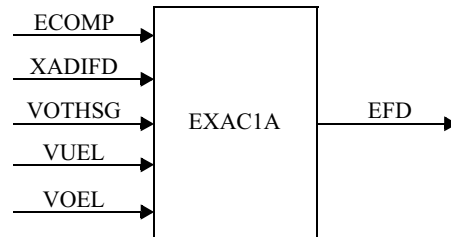
CONs	#	Value	Description
J			T_R (sec)
J+1			K_A
J+2			T_A (sec)
J+3			T_B (sec)
J+4			T_C (sec)
J+5			V_{RMAX} or zero
J+6			V_{RMIN}
J+7			K_E or zero
J+8			T_E (>0) (sec)
J+9			K_F
J+10			T_{F1} (>0) (sec)
J+11		0.0	Switch
J+12			E_1
J+13			$S_E(E_1)$
J+14			E_2
J+15			$S_E(E_2)$

STATEs	#	Description
K		Sensed V_T
K+1		Lead lag
K+2		Regulator output, V_R
K+3		Exciter output, EFD
K+4		Rate feedback integrator

6.25 EXAC1A

IEEE Modified Type AC1 Excitation System

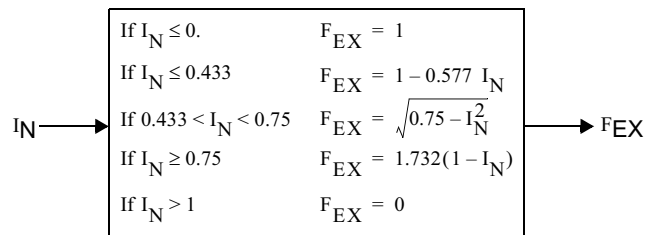
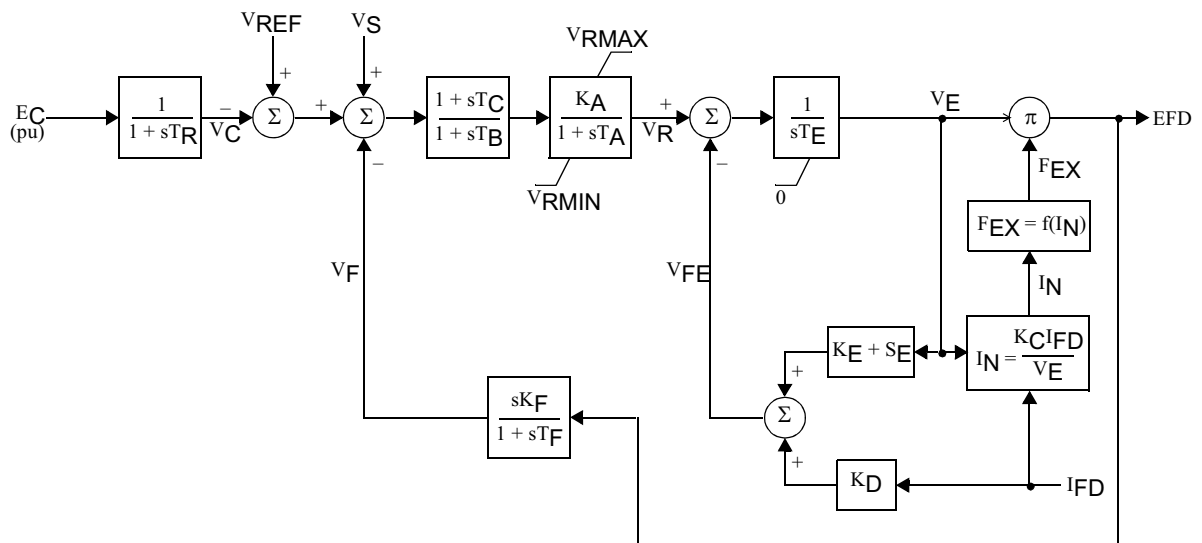
This model is located at system bus # _____ IBUS,
Machine identifier # _____ ID,
This model uses CONs starting with # _____ J,
and STATEs starting with # _____ K.



CONs	#	Value	Description
J			T_R (sec)
J+1			T_B (sec)
J+2			T_C (sec)
J+3			K_A
J+4			T_A (sec)
J+5			V_{RMAX}
J+6			V_{RMIN}
J+7			$T_E > 0$ (sec)
J+8			K_F
J+9			$T_F > 0$ (sec)
J+10			K_C
J+11			K_D
J+12			K_E
J+13			E_1
J+14			$S_E(E_1)$
J+15			E_2
J+16			$S_E(E_2)$

STATes	#	Description
K		Sensed E_T
K+1		Lead lag
K+2		Regulator output
K+3		V_E
K+4		Feedback output

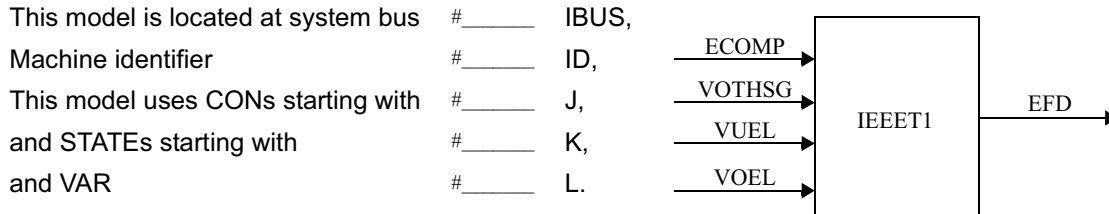
IBUS, 'EXAC1A', ID, CON(J) to CON(J+16) /



$V_S = V_{OTHSG} + V_{UEL} + V_{OEL}$

6.39 IEEEET1

IEEE Type 1 Excitation System

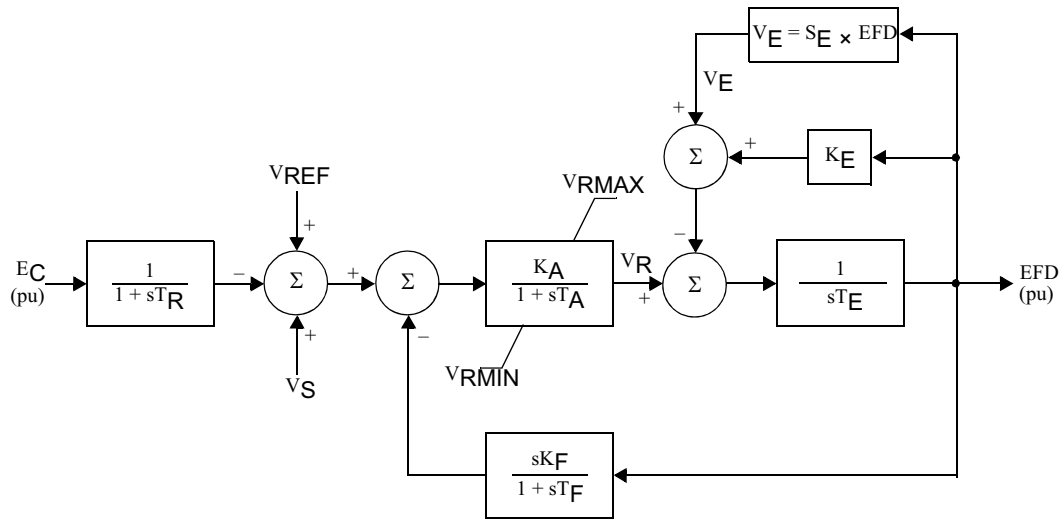


CONs	#	Value	Description
J			T_R (sec)
J+1			K_A
J+2			T_A (sec)
J+3			V_{RMAX} or zero
J+4			V_{RMIN}
J+5			K_E or zero
J+6			$T_E (>0)$ (sec)
J+7			K_F
J+8			$T_F (>0)$ (sec)
J+9		0	Switch
J+10			E_1
J+11			$S_E(E_1)$
J+12			E_2
J+13			$S_E(E_2)$

STATEs	#	Description
K		Sensed V_T
K+1		Regulator output, V_R
K+2		Exciter output, EFD
K+3		Rate feedback integrator

VAR	#	Description
L		K_E

IBUS, 'IEEEET1', ID, CON(J) to CON(J+13) /



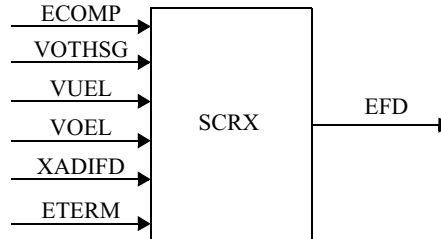
$V_S = V_{OTHSG} + V_{UEL} + V_{OEL}$

Note: S_E is the saturation function.

6.57 SCR X

Bus Fed or Solid Fed Static Exciter

This model is located at system bus # _____ IBUS,
Machine identifier # _____ ID,
This model uses CONs starting with # _____ J,
and STATEs starting with # _____ K.

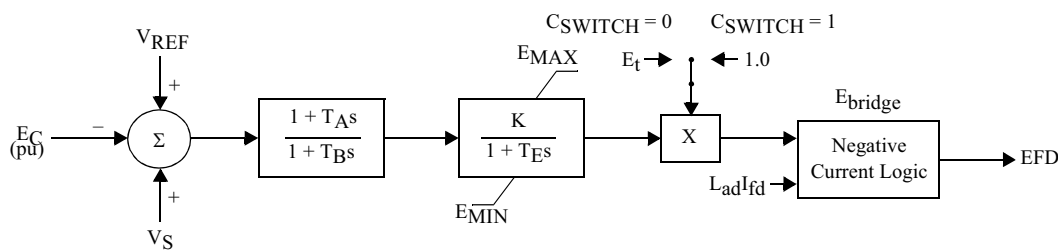


CONs	#	Value	Description
J			T_A/T_B
J+1			$T_B (>0)$ (sec)
J+2			K
J+3			T_E (sec)
J+4			E_{MIN} (pu on EFD base)
J+5			E_{MAX} (pu on EFD base)
J+6			C_{SWITCH}^1
J+7			r_c / r_{fd}^2

- ¹ Set $C_{SWITCH} = 0$ for bus fed.
Set $C_{SWITCH} = 1$ for solid fed.
² Set $CON(J+7) = 0$ for exciter with negative field current capability.
Set $CON(J+7) > 0$ for exciter without negative field current capability.
(Typical $CON(J+7) = 10$)

STATEs	#	Description
K		First integrator
K+1		Second integrator

IBUS, 'SCR X', ID, CON(J) to CON(J+7) /

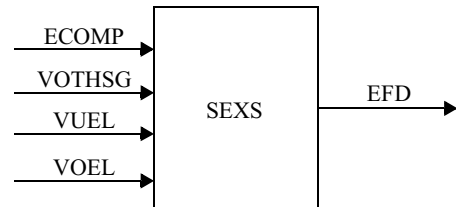


$$V_S = V_{OTHSG} + V_{UEL} + V_{OEL}$$

6.58 SEXS

Simplified Excitation System

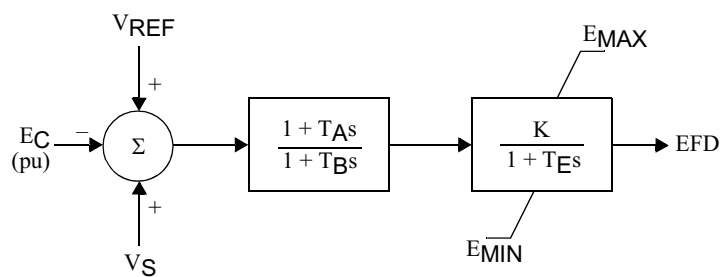
This model is located at system bus # _____ IBUS,
Machine identifier # _____ ID,
This model uses CONs starting with # _____ J,
and STATEs starting with # _____ K.



CONs	#	Value	Description
J			T_A/T_B
J+1			$T_B (>0)$ (sec)
J+2			K
J+3			T_E (sec)
J+4			E_{MIN} (pu on EFD base)
J+5			E_{MAX} (pu on EFD base)

STATEs	#	Description
K		First integrator
K+1		Second integrator

IBUS, 'SEXS', ID, CON(J) to CON(J+5) /



$$V_S = V_{OTHSG} + V_{UEL} + V_{OEL}$$

6.8 AC7B

IEEE 421.5 2005 AC7B Excitation System

This model is located at system bus #_____ IBUS,
 Machine identifier #_____ ID,
 This model uses CONs starting with #_____ J,
 and STATEs starting with #_____ K,
 and VARs starting with #_____ L.

CONs	#	Value	Description
J			T_R (sec) regulator input filter time constant
J+1			K_{PR} (pu) regulator proportional gain
J+2			K_{IR} (pu) regulator integral gain
J+3			K_{DR} (pu) regulator derivative gain
J+4			T_{DR} (sec) regulator derivative block time constant
J+5			V_{RMAX} (pu) regulator output maximum limit
J+6			V_{RMIN} (pu) regulator output minimum limit
J+7			K_{PA} (pu) voltage regulator proportional gain
J+8			K_{IA} (pu) voltage regulator integral gain
J+9			V_{AMAX} (pu) regulator output maximum limit
J+10			V_{AMIN} (pu) regulator output minimum limit
J+11			K_P (pu) ¹
J+12			K_L (pu)
J+13			K_{F1} (pu)
J+14			K_{F2} (pu)
J+15			K_{F3} (pu)
J+16			T_{F3} (sec) time constant (> 0)
J+17			K_C (pu) rectifier loading factor proportional to commutating reactance
J+18			K_D (pu) demagnetizing factor, function of AC exciter reactances
J+19			K_E (pu) exciter constant related fo self-excited field
J+20			T_E (pu) exciter time constant (>0)
J+21			V_{FEMAX} (pu) exciter field current limit (> 0)
J+22			V_{EMIN} (pu)

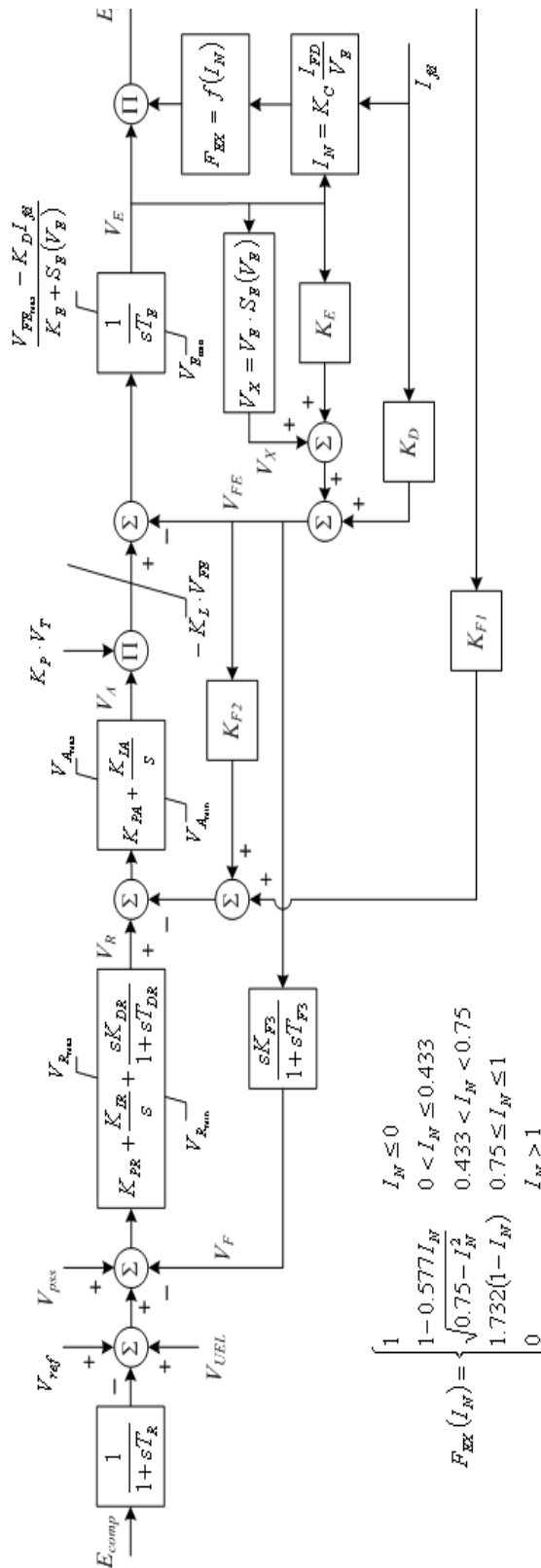
CONs	#	Value	Description
J+23			E1
J+24			S(E1)
J+25			E2
J+26			S(E2)

¹ Setting KP = 0 eliminates the multiplication of VA by terminal voltage VT.

STATES	#	Description
K		Sensed V_t
K+1		Integral channel 1
K+2		Derivative channel 1
K+3		Integral channel 2
K+4		V_E
K+5		Rate feedback

VARs	#	Description
L		V_R
L+1		V_A

IBUS, 'AC7B', ID, CON(J) to CON(J+26) /

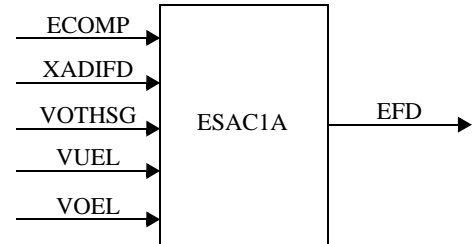


Note: If K_P is zero, the factor $K_P \cdot V_T$ is ignored.

6.18 ESAC1A

IEEE Type AC1A Excitation System

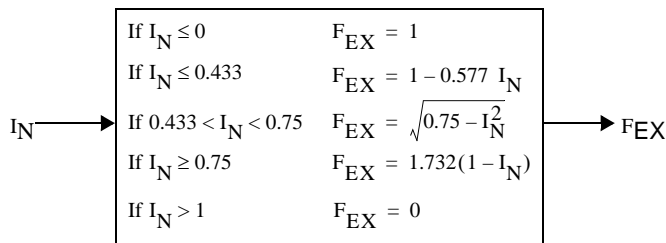
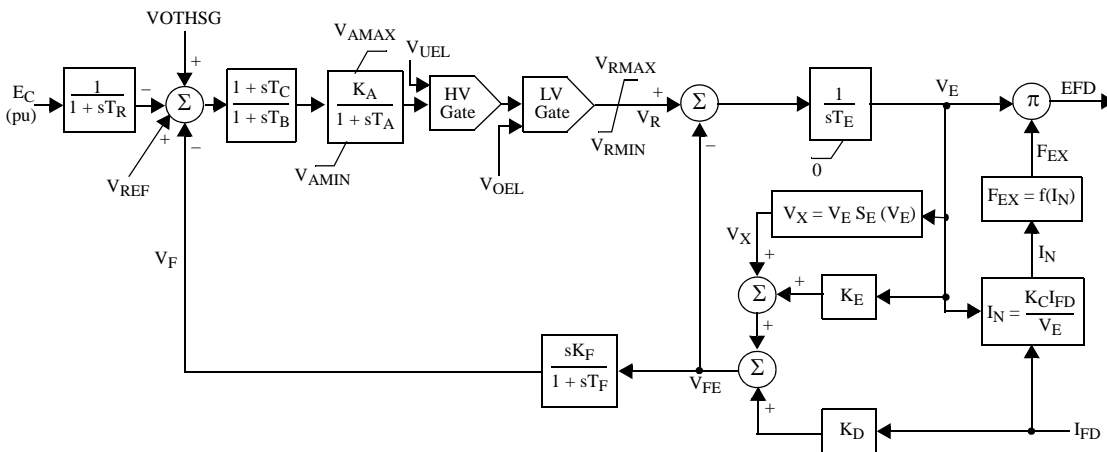
This model is located at system bus # _____ IBUS,
Machine identifier # _____ ID,
This model uses CONs starting with # _____ J,
and STATES starting with # _____ K.



CONs	#	Value	Description
J			T_R (sec)
J+1			T_B (sec)
J+2			T_C (sec)
J+3			K_A
J+4			T_A (sec)
J+5			V_{AMAX}
J+6			V_{AMIN}
J+7			$T_E > 0$ (sec)
J+8			K_F
J+9			$T_F > 0$ (sec)
J+10			K_C
J+11			K_D
J+12			K_E
J+13			E_1
J+14			$S_E(E_1)$
J+15			E_2
J+16			$S_E(E_2)$
J+17			V_{RMAX}
J+18			V_{RMIN}

STATES	#	Description
K		Sensed E_T
K+1		Lead lag
K+2		Regulator output
K+3		V_E
K+4		Feedback output

IBUS, 'ESAC1A', ID, CON(J) to CON(J+18) /



GOVERNOR MODELS

7.34 TGOV1DU

Steam Turbine-Governor

This model is located at system bus #_____ IBUS,
 Machine identifier #_____ ID,
 This model uses CONs starting with #_____ J,
 and STATEs starting with #_____ K,
 and VAR #_____ L.

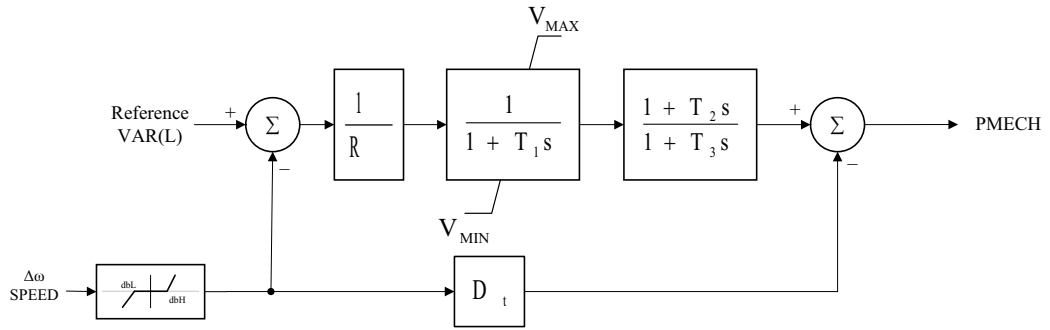
CONs	#	Value	Description
J			R
J+1			T ₁ (>0) (sec)
J+2			V _{MAX} ¹
J+3			V _{MIN} ¹
J+4			T ₂ (sec) ²
J+5			T ₃ (>0) (sec) ³
J+6			D _t ¹
J+7			DBH (pu), drop for over-speed, (≥ 0)
J+8			DBL (pu), droop for under-speed (≤ 0)
J+9			T _{Rate} (MW), Turbine rating, if zero, then MBASE used

- ¹ V_{MAX}, V_{MIN}, D_t and R are in per unit on generator MVA base.
- ² T₂/T₃ = high-pressure fraction.
- ³ T₃ = reheater time constant.

STATEs	#	Description
K		Valve opening
K+1		Turbine power

VARs	#	Description
L		Reference
L+1		Deadband output

IBUS, 'USRMDL', ID, 'TGOV1DU' 5 0 0 10 2 2 CON(J) to CON(J+9) /



7.15 HYGOVDU

Hydro Turbine-Governor

This model is located at system bus #_____ IBUS,
 Machine identifier #_____ ID,
 This model uses CONs starting with #_____ J,
 and STATEs starting with #_____ K,
 and VARs starting with #_____ L.

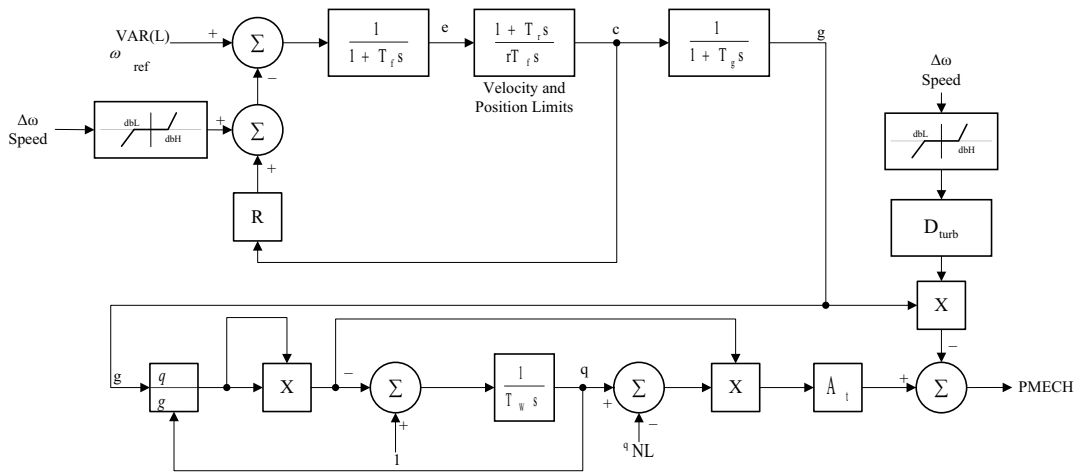
CONs	#	Value	Description
J			R, permanent droop
J+1			r, temporary droop
J+2			$T_r (>0)$ governor time constant
J+3			$T_f (>0)$ filter time constant
J+4			$T_g (>0)$ servo time constant
J+5			\pm VELM, gate velocity limit
J+6			G _{MAX} , maximum gate limit
J+7			G _{MIN} , minimum gate limit
J+8			$T_w (>0)$ water time constant
J+9			A _t , turbine gain
J+10			D _{turb} , turbine damping
J+11			q _{NL} , no power flow
J+12			DBH (pu), droop for over-speed, (≥ 0)
J+13			DBL (pu), droop for under-speed, (≤ 0)
J+14			T _{Rate} (MW), turbine rating, if zero, then MBASE used

STATEs	#	Description
K		e, filter output
K+1		c, desired gate
K+2		g, gate opening
K+3		q, turbine flow

VARs	#	Description
L		Speed reference
L+1		h, turbine head
L+2		Deadband output

R, r, and D_{turb} are in pu on T_{Rate} if $T_{\text{Rate}} > 0$, else in pu on generator MVA base.

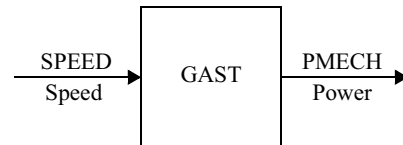
IBUS, 'USRMDL', ID, 'HYDGOVDU' 5 0 0 15 4 3 CON(J) to CON(J+14) /



7.5 GAST

Gas Turbine-Governor

This model is located at system bus #_____ IBUS,
Machine identifier #_____ ID,
This model uses CONs starting with #_____ J,
and STATEs starting with #_____ K,
and VAR #_____ L.



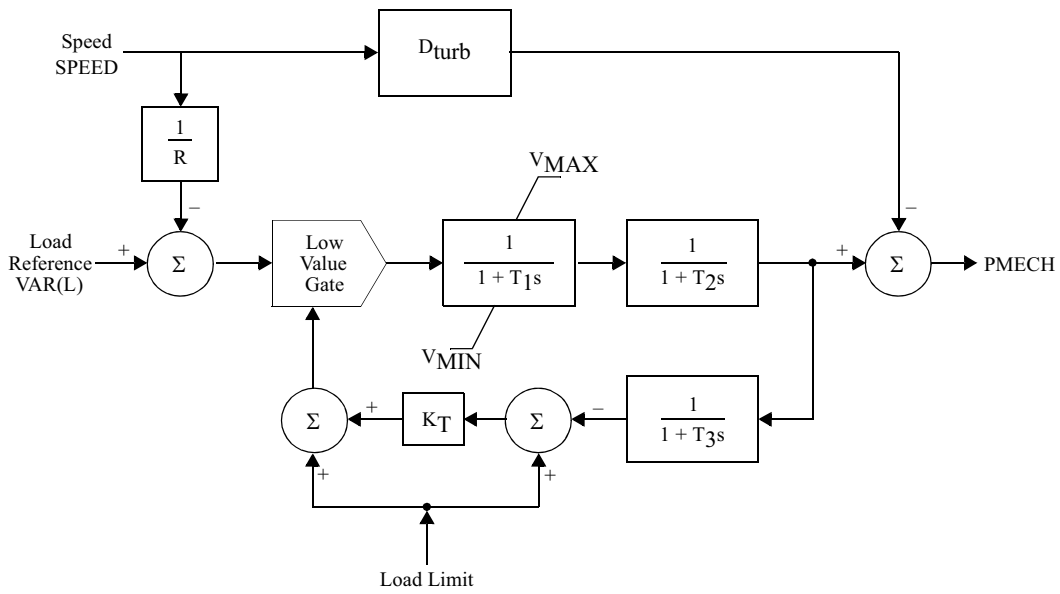
CONs	#	Value	Description
J			R (speed droop)
J+1			T ₁ (>0) (sec)
J+2			T ₂ (>0) (sec)
J+3			T ₃ (>0) (sec)
J+4			Ambient temperature load limit, AT
J+5			K _T
J+6			V _{MAX}
J+7			V _{MIN}
J+8			D _{turb}

STATEs	#	Description
K		Fuel valve
K+1		Fuel flow
K+2		Exhaust temperature

VAR	#	Description
L		Load reference

V_{max}, V_{min}, D_{turb} and R are in pu on generator MVA base.

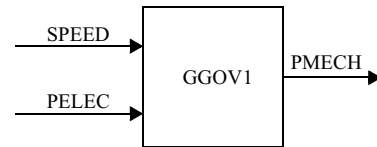
IBUS, 'GAST', ID, CON(J) to CON(J+8) /



7.8 GGOV1

GE General Governor/Turbine Model

This model is located at system bus #_____ IBUS,
Machine identifier #_____ ID,
This model uses CONs starting with #_____ J,
and STATEs starting with #_____ K,
and VARs starting with #_____ L,
and ICONs starting with #_____ M.



CONs	#	Value	Description
J			R, Permanent droop, pu
J+1			Tpelec, Electrical power transducer time constant, sec
J+2			maxerr, Maximum value for speed error signal
J+3			minerr, Minimum value for speed error signal
J+4			Kpgov, Governor proportional gain
J+5			Kigov, Governor integral gain
J+6			Kdgov, Governor derivative gain
J+7			Tdgov, Governor derivative controller time constant, sec
J+8			vmax, Maximum valve position limit
J+9			vmin, Minimum valve position limit
J+10			Tact, Actuator time constant, sec
J+11			Kturb, Turbine gain
J+12			Wfnl, No load fuel flow, pu
J+13			Tb, Turbine lag time constant, sec
J+14			Tc, Turbine lead time constant, sec
J+15			Teng, Transport lag time constant for diesel engine, sec
J+16			Tfload, Load Limiter time constant, sec
J+17			Kpload, Load limiter proportional gain for PI controller
J+18			Kiload, Load limiter integral gain for PI controller
J+19			Ldref, Load limiter reference value pu
J+20			Dm, Mechanical damping coefficient, pu
J+21			Ropen, Maximum valve opening rate, pu/sec
J+22			Rclose, Maximum valve closing rate, pu/sec
J+23			Kimw, Power controller (reset) gain
J+24			Aset, Acceleration limiter setpoint, pu/sec
J+25			Ka, Acceleration limiter gain

CONs	#	Value	Description
J+26			Ta, Acceleration limiter time constant, sec (> 0)
J+27			Trate, Turbine rating (MW) ¹
J+28			db, Speed governor deadband
J+29			Tsa, Temperature detection lead time constant, sec
J+30			Tsb, Temperature detection lag time constant, sec
J+31			Rup, Maximum rate of load limit increase
J+32			Rdown, Maximum rate of load limit decrease

¹ If the turbine rating [CON(J+27)] is greater than zero, the input PELEC is converted in the model to per unit on turbine rating base, else PELEC is converted to per unit on machine base.

STATES	#	Description
K		Machine Electrical Power Measurement
K+1		Governor Differential Control
K+2		Governor Integral Control
K+3		Turbine Actuator
K+4		Turbine Lead-Lag
K+5		Turbine load limiter measurement
K+6		Turbine Load Limiter Integral Control
K+7		Supervisory Load Control
K+8		Acceleration Control
K+9		Temperature Detection Lead-Lag

VARs	#	Description
L		Load Reference
L+1		Output of Load Limiter PI Control
L+2		Output of Governor PID Control
L+3		Low Value Select Output
L+4		Output of Turbine Actuator
L+5		Output of Turbine Lead-Lag
L+6		Supervisory Load Controller Setpoint, P _{mwset}
L+7 . . . L+19		Delay Table
L+20		Dead Band

ICONS	#	Value	Description
M		1	Rselect, Feedback signal for governor droop: 1 electrical power 0 none (isochronous governor) -1 fuel valve stroke (true stroke) -2 governor output (requested stroke)
M+1		0	Flag Switch for fuel source characteristic: 0 fuel flow independent of speed 1 fuel flow proportional to speed

R and DM in pu on Turbine MW base when Trate is specified and in pu on generator MVA base when Trate is not entered.

IBUS, 'GGOV1', ID, ICON(M) and ICON(M+1), CON(J) to CON(J+32) /

Notes:

- a. This model can be used to represent a variety of prime movers controlled by PID governors. It is suitable, for example, for representation of:
 - gas turbine and single shaft combined cycle turbines
 - diesel engines with modern electronic or digital governors
 - steam turbines where steam is supplied from a large boiler drum or a large header whose pressure is substantially constant over the period under study
 - simple hydro turbines in dam configurations where the water column length is short and water inertia effects are minimal
- b. Per unit parameters are on base of the turbine MW base (T_{rate}). If no value is entered for T_{rate} , parameters are specified on generator MVA base.
- c. The range of fuel valve travel and of fuel flow is unity. Thus the largest possible value of V_{max} is 1.0 and the smallest possible value of V_{min} is zero. V_{max} may, however, be reduced below unity to represent a loading limit that may be imposed by the operator or a supervisory control system. For gas turbines V_{min} should normally be greater than zero and less than w_{fni} to represent a minimum firing limit. The value of fuel flow at maximum output must be less than, or equal to unity, depending on the value of k_{turb} .
- d. The parameter T_{eng} is provided for use in representing diesel engines where there is a small but measurable transport delay between a change in fuel flow setting and the development of torque. In the majority of cases T_{eng} should be zero.
- e. The parameter Flag is provided to recognize that fuel flow, for a given fuel valve stroke, can be proportional to engine speed. This is the case for GE gas turbines and for diesel engines with positive displacement fuel injectors. Flag should be set to unity for all GE gas turbines and most diesel engines. Flag should be set to zero where it is known that the fuel control system keeps fuel flow independent of engine speed.
- f. The load limiter module may be used to impose a maximum output limit such as an exhaust temperature limit. To do this the time constant T_{load} should be set to represent the time constant in the measurement of temperature (or other signal), and the gains of the limiter, K_{pload} , K_{iload} , should be set to give prompt stable control when on limit. The load limit can be deactivated by setting the parameter L_{dref} to a high value.
- g. The parameter D_m can represent either the variation of engine power with shaft speed or the variation of maximum power capability with shaft speed.

If D_m is positive it describes the falling slope of the engine speed versus power characteristic as speed increases. A slightly falling characteristic is typical for reciprocating engines and some aeroderivative turbines.

If D_m is negative the engine power is assumed to be unaffected by shaft speed, but the maximum permissible fuel flow is taken to fall with falling shaft speed. This is characteristic of single shaft industrial gas turbines.
- h. This model includes a simple representation of a supervisory load controller. This controller is active if the parameter K_{imw} is non-zero. The load controller is a slow acting reset loop that adjusts the speed/load reference of the turbine governor to hold the electrical power output of the unit at its initial condition value P_{mwset} .

P_{mwset} is given a value automatically when the model is initialized and stored in VAR(L+6), and can be changed thereafter. The load controller must be adjusted to respond gently relative to the speed governor. A typical value for K_{imw} is 0.01, corresponding to a reset time of 100 seconds. Setting K_{imw} to 0.001 corresponds to a relatively slow acting load controller.

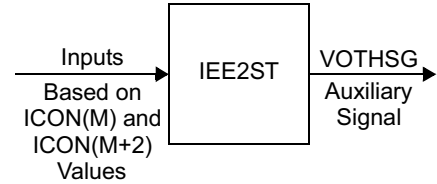
- i. The parameters A_{set} , K_a , and T_a describe an acceleration limiter. These parameters may be set to zero if the limiter is not active.
- j. The parameter db is the speed governor dead band. This parameter is in terms of per unit speed.
- k. T_{sa} and T_{sb} are provided to augment the exhaust gas temperature measurement subsystem in gas turbines.
- l. R_{up} and R_{down} specify the maximum rate of increase and decrease of the output of the load limit controller (K_{pload}/K_{iload}).

STABILIZER MODELS

3.2 IEE2ST

IEEE Stabilizing Model With Dual-Input Signals

This model is located at system bus # _____ IBUS,
 Machine identifier # _____ ID,
 This model uses CONs starting with # _____ J,
 and STATEs starting with # _____ K,
 and VARs starting with # _____ L,
 and ICONS starting with # _____ M.



CONs	#	Value	Description
J			K_1
J+1			K_2
J+2			T_1 (sec)
J+3			T_2 (sec)
J+4			T_3 (sec) ¹
J+5			T_4 (>0) (sec)
J+6			T_5 (sec)
J+7			T_6 (sec)
J+8			T_7 (sec)
J+9			T_8 (sec)
J+10			T_9 (sec)
J+11			T_{10} (sec)
J+12			L_{SMAX}
J+13			L_{SMIN}
J+14			V_{CU} (pu) (if equal zero, ignored.)
J+15			V_{CL} (pu) (if equal zero, ignored.)

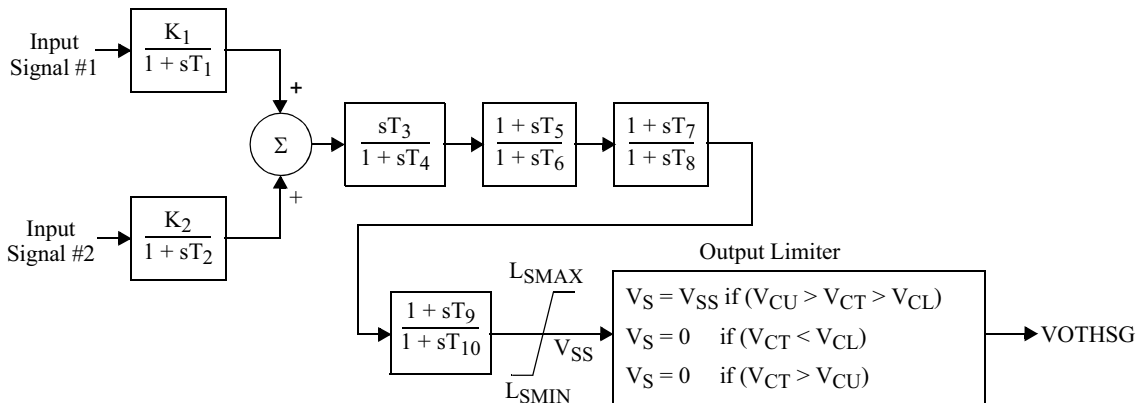
¹ If T_3 equals 0, sT_3 will equal 1.0.

STATes	#	Description
K		First signal transducer
K+1		Second signal transducer
K+2		Washout
K+3		First lead-lag
K+4		Second lead-lag
K+5		Third lead-lag

VARs	#	Description
L		Memory
L+1		Derivative of pu bus voltage, first bus
L+2		Memory
L+3		Derivative of pu bus voltage, second bus

ICONS	#	Value	Description
M			ICS1, first stabilizer input code: 1 rotor speed deviation (pu) 2 bus frequency deviation (pu) 3 generator electrical power on MBASE base (pu) 4 generator accelerating power (pu) 5 bus voltage (pu) 6 derivative of pu bus voltage
M+1			IB1, first remote bus number
M+2			ICS2, second stabilizer input code
M+3			IB2, second remote bus number

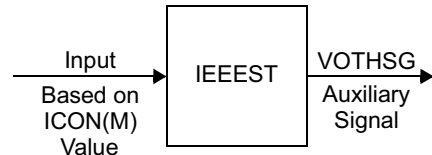
IBUS, 'IEE2ST', ID, ICON(M) to ICON(M+3), CON(J) to CON(J+15) /



3.3 IEEEEST

IEEE Stabilizing Model

This model is located at system bus # _____ IBUS,
 Machine identifier # _____ ID,
 This model uses CONs starting with # _____ J,
 and STATEs starting with # _____ K,
 and VARs starting with # _____ L,
 and ICONs starting with # _____ M.



CONs	#	Value	Description
J			A ₁
J+1			A ₂
J+2			A ₃
J+3			A ₄
J+4			A ₅
J+5			A ₆
J+6			T ₁ (sec)
J+7			T ₂ (sec)
J+8			T ₃ (sec)
J+9			T ₄ (sec)
J+10			T ₅ (sec) ¹
J+11			T ₆ (>0) (sec)
J+12			K _S
J+13			L _S MAX
J+14			L _S MIN
J+15			V _{CU} (pu) (if equal zero, ignored)
J+16			V _{CL} (pu) (if equal zero, ignored.)

¹ If T₅ equals 0, sT₅ will equal 1.0.

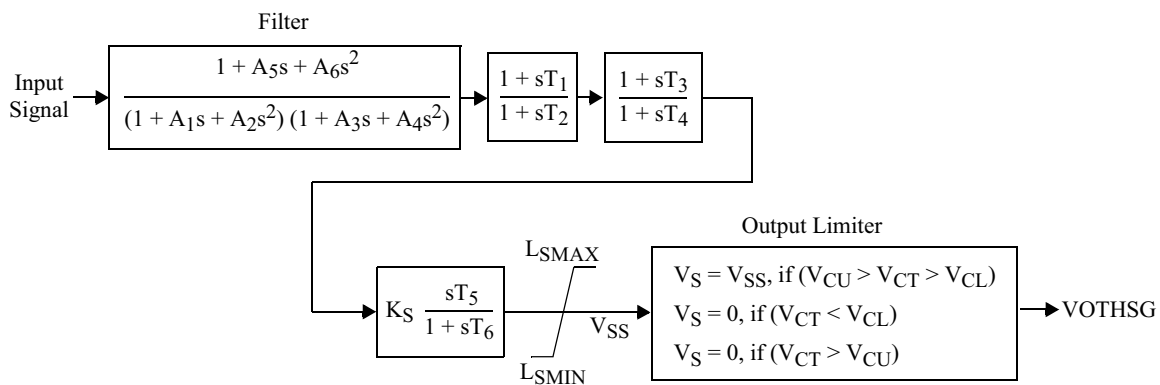
STATes	#	Description
K		1st filter integration
K+1		2nd filter integration
K+2		3rd filter integration
K+3		4th filter integration
K+4		T ₁ /T ₂ lead-lag integrator
K+5		T ₃ /T ₄ lead-lag integrator
K+6		Last integer

VARs	#	Description
L		Memory
L+1		Derivative of pu bus voltage

ICONS	#	Value	Description
M			Stabilizer input code: 1 rotor speed deviation (pu) 2 bus frequency deviation (pu) 3 generator electrical power on MBASE base (pu) 4 generator accelerating power (pu) 5 bus voltage (pu) 6 derivative of pu bus voltage
M+1			IB, remote bus number 2, 5, 6 1, 2

- 1 ICON(M+1) may be nonzero only when ICON(M) is 2, 5, or 6.
- 2 If ICON(M+1) is zero, the terminal quantity is used.

IBUS, 'IEEEEST', ID, ICON(M) and ICON(M+1), CON(J) to CON(J+16) /



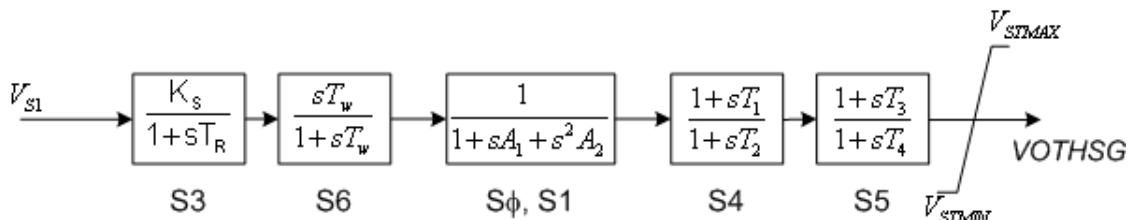
3.7 PSS1A

IEEE Std. 421.5-2005 PSS1A Single-Input Stabilizer Model

The PSS®E model **IEEEEST** can be used to simulate the PSS1A model. The correspondence between the IEEEEST model CONs and the PSS1A parameters (shown in the block) diagram are as given in the table below.

CONs	IEEEEST CON	PSS1A parameter (as shown in the PSS1A block diagram)
J	A ₁	A ₁
J+1	A ₂	A ₂
J+2	A ₃	T _R
J+3	A ₄	0.0
J+4	A ₅	0.0
J+5	A ₆	0.0
J+6	T ₁	T ₁
J+7	T ₂	T ₂
J+8	T ₃	T ₃
J+9	T ₄	T ₄
J+10	T ₅	T _w
J+11	T ₆	T _w
J+12	K _S	K _S
J+13	L _S MAX	V _{ST} MAX
J+14	L _S MIN	V _{ST} MIN
J+15	V _{CU}	0.0
J+16	V _{CL}	0.0

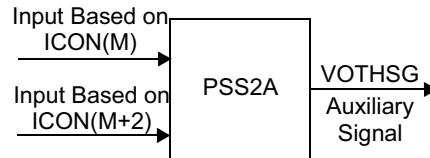
IBUS, 'IEEEEST', ID, ICON(M), ICON(M+1), CON(J) to CON(J+16) /



3.8 PSS2A

IEEE Dual-Input Stabilizer Model

This model is located at system bus # _____ IBUS,
 Machine identifier # _____ ID,
 This model uses CONs starting with # _____ J,
 and STATEs starting with # _____ K,
 and VARs starting with # _____ L,
 and ICONs starting with # _____ M.



CONs	#	Value	Description
J			$T_{w1} (>0)$
J+1			T_{w2}
J+2			T_6
J+3			$T_{w3} (>0)$
J+4			T_{w4}
J+5			T_7
J+6			K_{S2}
J+7			K_{S3}
J+8			T_8
J+9			$T_9 (>0)$
J+10			K_{S1}
J+11			T_1
J+12			T_2
J+13			T_3
J+14			T_4
J+15			V_{STMAX}
J+16			V_{STMIN}

STATEs	#	Description
K		Washout, first signal
K+1		Washout, first signal
K+2		Transducer, first signal
K+3		Washout, second signal
K+4		Washout, second signal
K+5		Transducer, second signal
K+6 . . . K+13		Ramp Tracking Filter
K+14		First lead-lag
K+15		Second lead-lag

VARs	#	Description
L		Memory
L+1		Derivative of pu bus voltage, first bus
L+2		Memory
L+3		Derivative of pu bus voltage, second bus

ICONS	#	Value	Description
M			ICS1, first stabilizer input code: 1 rotor speed deviation (pu) 2 bus frequency deviation (pu) 3 generator electrical power on MBASE base (pu) 4 generator accelerating power (pu) 5 bus voltage (pu) 6 derivative of pu bus voltage
M+1			REMBUS1, first remote bus number
M+2			ICS2, second stabilizer input code: 1 rotor speed deviation (pu) 2 bus frequency deviation (pu) 3 generator electrical power on MBASE base (pu) 4 generator accelerating power (pu) 5 bus voltage (pu) 6 derivative of pu bus voltage

ICONS	#	Value	Description
M+3			REMBUS2, second remote bus number
M+4			M, ramp tracking filter
M+5			N, ramp tracking filter

Model Notes:

Ramp Tracking Filter

$M \geq 0$
 $N \geq 0$
 $M * N \leq 8$
 If $M = 0$, then N is set equal to 0

To bypass: set $M = N = 0$

Washouts

To bypass second washout, first signal: set $T_{w2} = 0$
 To bypass second washout, second signal: set $T_{w4} = 0$

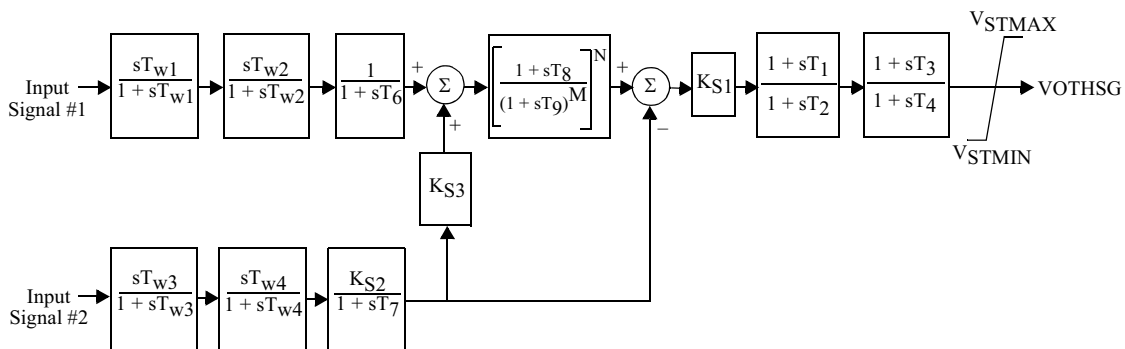
Transducers

To bypass first signal transducer: set $T_6 = 0$
 To bypass second signal transducer: set $T_7 = 0$

Lead-Lags

To bypass first lead-lag: set $T_1 = T_2 = 0$
 To bypass second lead-lag: set $T_3 = T_4 = 0$

IBUS, 'PSS2A', ID, ICON(M) to ICON(M+5), CON(J) to CON(J+16) /



3.9 PSS2B

IEEE 421.5 2005 PSS2B IEEE Dual-Input Stabilizer Model

This model is located at system bus # _____ IBUS,
 Machine identifier # _____ ID.
 This model uses CONs starting with # _____ J,
 and STATEs starting with # _____ K,
 and VARs starting with # _____ L,
 and ICONs starting with # _____ M.

CONs	#	Value	Description
J			$T_{w1} (> 0)$
J+1			T_{w2}
J+2			T_6
J+3			T_{w3}
J+4			T_{w4}
J+5			T_7
J+6			K_{S2}
J+7			K_{S3}
J+8			T_8
J+9			$T_9 (> 0)$
J+10			K_{S1}
J+11			T_1
J+12			T_2
J+13			T_3
J+14			T_4
J+15			T_{10}
J+16			T_{11}
J+17			V_{S1MAX}
J+18			V_{S1MIN}
J+19			V_{S2MAX}
J+20			V_{S2MIN}
J+21			V_{STMAX}
J+22			V_{STMIN}

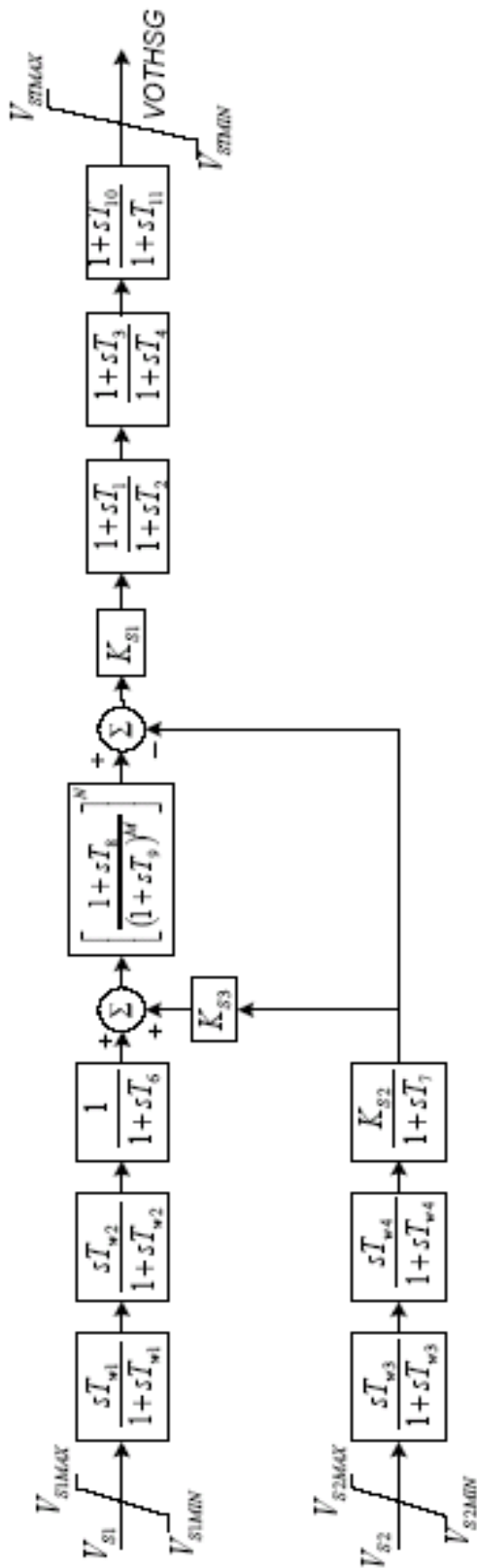
STATES	#	Description
K		Washout-first signal
K+1		Washout-first signal
K+2		Transducer-first signal
K+3		Washout-second signal
K+4		Washout-second signal
K+5		Transducer-second signal
K+6 . . . K+13		Ramp tracking filter
K+14		First lead-lag
K+15		Second lead-lag
K+16		Third lead-lag

VARs	#	Description
L		Memory
L+1		Derivative of pu bus voltage-first bus
L+2		Memory
L+3		Derivative of pu bus voltage-second bus

ICON	#	Value	Description
M			ICS1, first stabilizer input code: 1 rotor speed deviation (pu) 2 bus frequency deviation (pu) 3 generator electrical power on MBASE base (pu) 4 generator accelerating power (pu) 5 bus voltage 6 derivative of pu bus voltage
M+1			REMBUS1, first remote bus to be entered as 0 for input codes 1, 3, and 4.
M+2			ICS2, second stabilizer input code: 1 rotor speed deviation (pu) 2 bus frequency deviation (pu) 3 generator electrical power on MBASE base (pu) 4 generator accelerating power (pu) 5 bus voltage 6 derivative of pu bus voltage
M+3			REMBUS2, second remote bus to be entered as 0 for input codes 1, 3, and 4.
M+4			M, ramp tracking filter
M+5			N, ramp tracking filter

IBUS, 'PSS2B', ID, ICON(M) to ICON(M+5), CON(J) to CON(J+22) /

SIEMENS



DC line model

13.5 CDC7T

dc Line Model

This model uses CONs starting with #_____ J,
and STATES starting with #_____ K,
and VARs starting with #_____ L,
and ICONs starting with #_____ M.

CONs	#	Value	Notation	Description
J			Ts_vdc	dc voltage sensor time constant, sec.
J+1			Ts_idc	dc current sensor time constant, sec.
J+2			LRR	Rectifier smoothing reactor inductance, mH
J+3			RRR	Rectifier smoothing reactor resistance, ohm
J+4			LRI	Inverter smoothing reactor inductance, mH
J+5			RRI	Inverter smoothing reactor resistance, ohm
J+6			LOHR	Inductance of O/H dc line from rectifier side, mH
J+7			ROHR	Resistance of O/H dc line from rectifier side, ohm
J+8			LOHI	Inductance of O/H dc line from inverter side, mH
J+9			ROHI	Resistance of O/H dc line from inverter side, ohm
J+10			LDCC	Inductance of dc cable line, mH
J+11			RDCC	Damping resistance of dc cable line, ohm
J+12			CDCC	dc line capacitance, μ F
J+13			LF1	dc fault shunt inductance, rectifier side, mH
J+14			RF1	dc fault shunt resistance, rectifier side, ohm
J+15			LF2	dc fault shunt inductance, mid-line, mH
J+16			RF2	dc fault shunt resistance, mid-line, ohm
J+17			LF3	dc fault shunt inductance, inverter side, mH
J+18			RF3	dc fault shunt resistance, inverter side, ohm
J+19			RCDCC	dc cable damping resistor
J+20			IDCRated	Rated dc current, A
J+21			VDCRated	Rated dc voltage, kV
J+22			VDCompR_Tdown	VDComp down time constant for VDCL, rectifier, sec
J+23			VDCompR_Tup	VDComp up time constant for VDCL, rectifier, sec

CONs	#	Value	Notation	Description
J+24			VDCmpl_Tdown	VDComp down time constant for VDCL, inverter, sec
J+25			VDCmpl_Tup	VDComp up time constant for VDCL, inverter, sec
J+26			IMargR	Current margin, rectifier, pu
J+27			IMargI	Current margin, inverter, pu
J+28			VMargR	Voltage margin, rectifier, pu
J+29			VMargI	Voltage margin, inverter, pu
J+30			GMargR	Gamma margin, rectifier, pu
J+31			GMargI	Gamma margin, inverter, pu
J+32			IDCERR_toV_GAIN_R	IDC error to V-control gain, rectifier
J+33			IDCERR_toV_GAIN_I	IDC error to V-control gain, inverter
J+34			IDCERR_toG_GAIN_I	IDC error to Gamma-control gain, inverter
J+35			VDComp_MEAS_GR	VDComp filter gain, rectifier, pu
J+36			VDComp_MEAS_GI	VDComp filter gain, inverter, pu
J+37			VDComp_MEAS_TR	VDComp filter time constant, rectifier, sec.
J+38			VDComp_MEAS_TR	VDComp filter time constant, inverter, sec.
J+39			DSEL_KBR	Selected controller output gain, rectifier
J+40			DSEL_KBI	Selected controller output gain, inverter
J+41			GPGR	PI-controller proportional gain, rectifier
J+42			TIGR	PI-controller integrator time constant, rectifier, sec.
J+43			GPGI	PI-controller proportional gain, inverter
J+44			TIGI	PI-controller integrator time constant, inverter, sec.
J+45			MAXALR	Max Alfa limit, rectifier
J+46			MINALR	Min Alfa limit, rectifier
J+47			MAXALI	Max Alfa limit, inverter
J+48			MINALI	Min Alfa limit, inverter
J+49			GAMA_ORDER1	Control configuration 1
J+50			GAMA_ORDER2	Control configuration 3
J+51			GAMDY	Min GAMA in dynamics
J+52			BLOCK_RATE	Rate of current order change when blocking, A/sec
J+53			UNBLOCK_RATE	Rate of current order change when unblocking, A/sec
J+54			TVDCP	VDC filter time constant for Pordr calculation, sec.

CONs	#	Value	Notation	Description
J+55 to J+64				5 pairs of rectifier VDCL coordinates (Vd1, Id1) ... (Vd5, Id5) ¹
J+65 to J+74				5 pairs of inverter VDCL coordinates (Vd1, Id1) ... (Vd5, Id5) ¹

¹ The VDCL characteristics can be specified using a minimum of 2 pairs and a maximum of 5 pairs of (Vd - Id) points. The rectifier data points are specified in CON (J+55) through CON(J+64), while the inverter data points are specified in CON(J+65) through CON(J+74). The first zero value for the (Vd - Id) pair signifies the end of VDCL data points.

STATES	#	Description
K		Measured dc voltage, inverter, V
K+1		Measured dc current, inverter, A
K+2		Measured dc voltage, rectifier, V
K+3		Measured dc current, rectifier, A
K+4		IDCR, Rectifier dc current, A
K+5		IDCI, Inverter dc current, A
K+6		VCDC, DC line capacitor voltage, V
K+7		Rectifier VDCComp filter, pu
K+8		Inverter VDCComp filter, pu
K+9		Rectifier VDCComp measured, pu
K+10		Inverter VDCComp measured, pu
K+11		PI controller integrator, rectifier, rad
K+12		PI controller integrator, inverter, rad
K+13		IF1, fault current dc fault 1
K+14		IF2, fault current dc fault 2
K+15		IF3, fault current dc fault 3
K+16		VDC filter for power order calculation

VARs	#	Description
L		Other signals, MW [DC2SIG (1, I)] ¹
L+1		PACR, pu active power at rectifier ac bus
L+2		QACR, pu reactive power at rectifier ac bus
L+3		PACI, pu active power at inverter ac bus
L+4		QACI, pu reactive power at inverter ac bus
L+5		VDCI, inverter dc voltage, V
L+6		VDCR, rectifier dc voltage, V
L+7		ALFA, degrees

VARs	#	Description
L+8		GAMA, degrees
L+9		Initial rectifier DC current order, A
L+10		Rectifier current order, limited by VDCL, pu
L+11		Inverter current order, limited by VDCL, pu
L+12		Current controller output, rectifier
L+13		Current controller output, inverter
L+14		Voltage controller output, rectifier
L+15		Voltage controller output, inverter
L+16		Gamma controller output, inverter
L+17		Selected controller output, rectifier
L+18		Selected controller output, inverter
L+19		Inverter Alpha, degrees
L+20		Initial VDCComp (compensated dc voltage)
L+21		DC current order for block/unblock and overload, A
L+22		IDC1, sending end dc current, A
L+23		IDC2, receiving end dc current, A
L+24		P _{ORD} , power order, pu
L+25		I _{order} , dc current order, pu

¹ CDC7T model can accept one auxiliary signal input (auxiliary signal index 1). The auxiliary signal has to be in units of MW. The auxiliary signal is summed with the power order, which is then used to derive the current order.

ICONS	#	Description
M		Blocking and Unblocking Simulation Flag: 0 none 1 blocking 2 unblocking
M+1		Overload Simulation Flag: 0 none 1 overload
M+2		Control configuration: 1, 2, or 3 ¹
M+3		1 cable or cable + overhead 2 overhead

¹ ICON(M+2) = 1 : Rectifier in dc current control; inverter in gamma control
 ICON(M+2) = 2 : Rectifier in dc current control; inverter in dc voltage control
 ICON(M+2) = 3 : Rectifier in dc voltage control; inverter in dc current control

'DC Line Name', CDC7T ', 0, 0, ICON(M+2), ICON(M+3), CON(J) to CON(J+74) /

Renewable Generator Models (2nd generation)

17.6 WT3G2

Doubly-Fed Induction Generator (Type 3)

This model is located at system bus #_____ IBUS,
 Machine identifier #_____ ID,
 This model uses CONs starting with #_____ J,
 and STATEs starting with #_____ K,
 and VAR #_____ L,
 and ICON #_____ M.

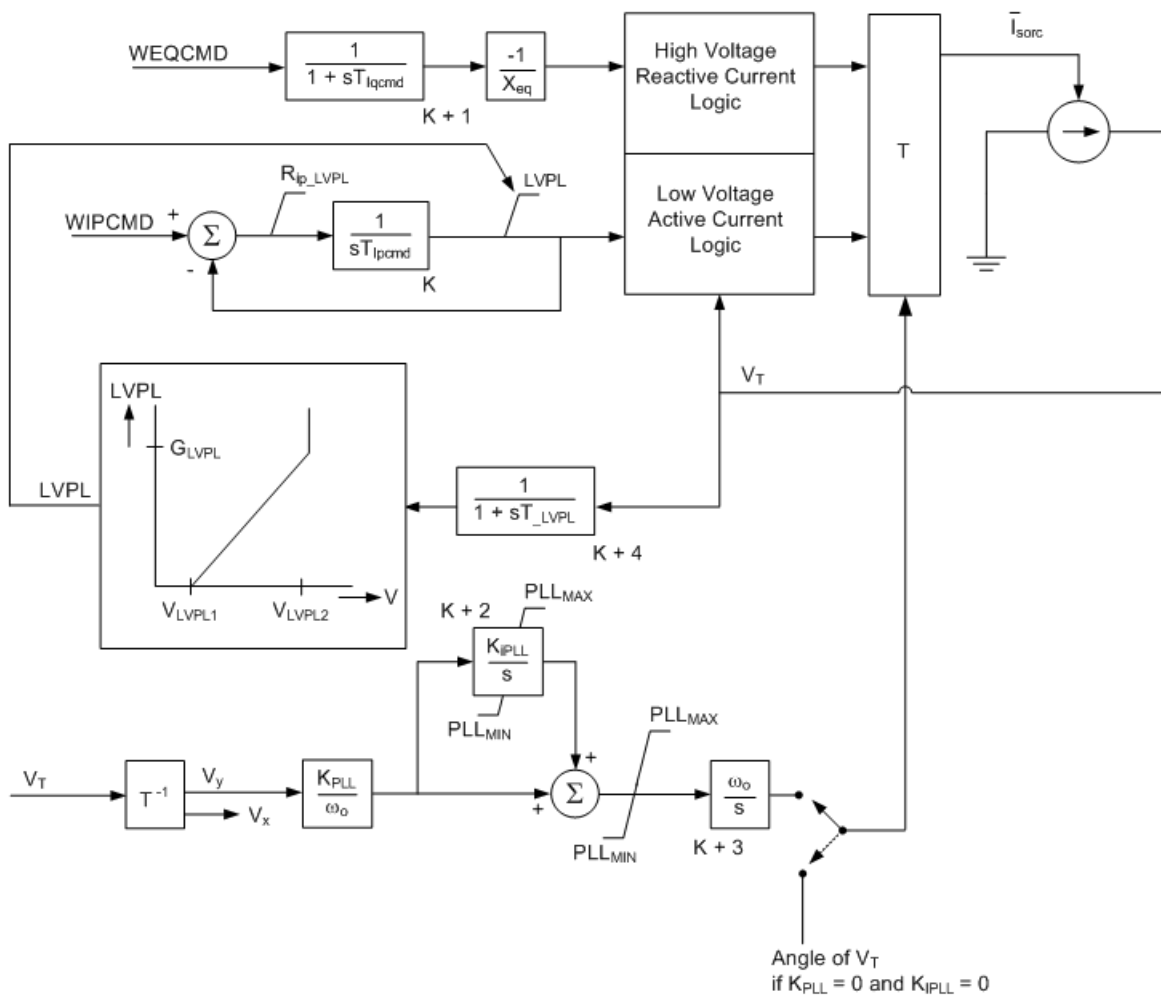
CONs	#	Value	Description
J			Tiqcmd, Converter time constant for IQcmd
J+1			Tipcmd, Converter time constant for IPcmd
J+2			K _{PLL} , PLL gain
J+3			K _{IPLL} , PLL integrator gain
J+4			PLL _{MAX} , PLL max. limit
J+5			Prated
J+6			V _{LVPL1} , LVPL voltage 1 Low voltage power logic
J+7			V _{LVPL2} , LVPL voltage 2
J+8			G _{LVPL} , LVPL gain
J+9			V _{HVRCR} , High Voltage Reactive Current (HVRC) logic, pu voltage
J+10			CUR _{HVRCR} , HVRC logic, current (pu)
J+11			R _{Ip_LVPL} , Rate of active current change
J+12			T _{LVPL} , Voltage sensor for LVPL, second

STATEs	#	Description
K		Converter lag for Ipcmd
K+1		Converter lag for Iqcmd
K+2		PLL first integrator
K+3		PLL second integrator
K+4		Voltage sensor for LVPL

VAR	#	Description
L		deltaQ, overvoltage correction factor

ICON	#	Description
M		Number of lumped wind turbines

IBUS, 'WT3G2', ID, ICON(M), CON(J) TO CON(J+12) /



17.8 WT4G2

Wind Generator Model with Power Converter (Type 4)

This model is located at system bus #_____ IBUS,
 Machine identifier #_____ ID,
 This model uses CONs starting with #_____ J,
 and STATEs starting with #_____ K,
 and VARs starting with #_____ L.

CONs	#	Value	Description
J			T _{IQCmd} , Converter time constant for IQcmd
J+1			T _{IPCmd} , Converter time constant for IPcmd
J+2			V _{LVPL1} , LVPL voltage 1 (Low voltage power logic)
J+3			V _{LVPL2} , LVPL voltage 2
J+4			G _{LVPL} , LVPL gain
J+5			V _{HVR} , HVR voltage (High voltage reactive current limiter)
J+6			C _{URHVR} , HVR current (Max. reactive current at V _{HVR})
J+7			R _{ip_LVPL} , Rate of LVACR active current change
J+8			T _{_LVPL} , Voltage sensor for LVACR time constant

STATEs	#	Description
K		Converter lag for Ipcmd
K+1		Converter lag for Eqcmd
K+2		Voltage sensor for LVACR

VARs	#	Description
L through L+4		For Internal Use

IBUS, 'WT4G2', ID CON(J) to CON(J+8) /

