MANUAL

ON

TRANSMISSION PLANNING CRITERIA

CENTRAL ELECTRICITY AUTHORITY

NEW DELHI

JANUARY 2013

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PREAMBLE

Manual on transmission planning criteria was first brought out by CEA in 1985 setting the planning philosophy of regional self sufficiency. The manual was revised in 1994 taking into account the experience gained on EHV systems. Technological advancements and institutional changes during last ten years have necessitated review of Transmission Planning Criteria. The regional electrical grids of Northern, Western, Eastern and North-Eastern regions have been synchronously interconnected to form one of the largest electrical grids in the world. The country has moved from the concept of regional self-sufficiency to bulk inter-regional transfer of power through high capacity AC and HVDC corridors forming an all-India National Grid.

The Electricity Act, 2003 has brought profound changes in electricity supply industry of India leading to unbundling of vertically integrated State Electricity Boards, implementation of Open Access in power transmission and liberalisation of generation sector. The phenomenal growth of private sector generation and the creation of open market for electricity have brought its own uncertainties. Large numbers of generation projects are coming up with no knowledge of firm beneficiaries. The situation is compounded by uncertainty in generation capacity addition, commissioning schedules and fuel availability. All these factors have made transmission planning a challenging task. Adequate flexibility may be built in the transmission system plan to cater to such uncertainties, to the extent possible. However, given the uncertainties, the possibility of stranded assets or congestion cannot be entirely ruled out.

In the creation of very large interconnected grid, there can be unpredictable power flows leading to overloading of transmission lines due to imbalance in load-generation balance in different pockets of the grid in real time operation. Reliable transmission planning is basically a trade-off between the cost and the risk involved. There are no widely adopted uniform guidelines which determine the criteria for transmission planning vis-à-vis acceptable degree of adequacy and security. Practices in this regard vary from country to country. The common theme in the various approaches is "acceptable system performance".

However, recent grid incidents of July 2012 have underlined the importance of grid security. As the grid grows in size and complexity, grid security has to be enhanced because the consequences of failure of a large grid are severe. The transmission planning criteria has been reviewed accordingly. The transmission planning criteria has also considered large scale integration of renewable energy sources.

MANUAL ON TRANSMISSION PLANNING CRITERIA

Scope and planning philosophy (Paragraph 1 to 3)

1. Scope

1.1 The Central Electricity Authority is responsible for preparation of perspective generation and transmission plans and for coordinating the activities of planning agencies as provided under Section 73(a) of the Electricity Act 2003. The Central Transmission Utility (CTU) is responsible for development of an efficient and coordinated inter-state transmission system (ISTS). Similarly, the State Transmission Utility (STU) is responsible for development of an efficient and coordinated intra-state transmission system (Intra-STS). The ISTS and Intra-STS are interconnected and together constitute the electricity grid. It is therefore imperative that there should be a uniform approach to transmission planning for developing a reliable transmission system.

1.2 The planning criteria detailed herein are primarily meant for planning of Inter-State Transmission System (ISTS) down to 132kV level and Intra-State Transmission System (Intra-STS) down to 66kV level, including the dedicated transmission lines.

1.3 The manual covers the planning philosophy, the information required from various entities, permissible limits, reliability criteria, broad scope of system studies, modeling and analysis, and gives guidelines for transmission planning.

2. Applicability

2.1 These planning criteria shall be applicable from the date it is issued by Central Electricity Authority i.e. 1st February 2013.

2.2 These criteria shall be used for all new transmission systems planned after the above date.

2.3 The existing and already planned transmission systems may be reviewed with respect to the provisions of these planning criteria. Wherever required and possible, additional system may be planned to strengthen the system.

Till implementation of the additional system, suitable defense mechanisms may have to be put into place.

3. Planning philosophy and general guidelines

3.1 The transmission system forms a vital link in the electricity supply chain. Transmission system provides 'service' of inter-connection between the source (generator) and consumption (load centers) of electricity. In the Indian context, the transmission system has been broadly categorised as Inter-State Transmission System(ISTS) and Intra-State Transmission system(Intra-STS). The ISTS is the top layer of national grid below which lies the Intra-STS. The smooth operation of power system gets adversely affected on account of any of these systems. Therefore, the criteria prescribed here are intended to be followed for planning of both ISTS and Intra-STS.

3.2 The transmission system is generally augmented to cater to the long term requirements posed by eligible entities, for example, for increase in power demand, generation capacity addition etc. Further, system may also be augmented considering the feedback regarding operational constraints and feedback from drawing entities.

3.3 The long term applicants seeking transmission service are expected to pose their end-to-end requirements well in advance to the CTU/STUs so as to make-available the requisite transmission capacity, and minimise situations of congestion and stranded assets.

3.4 The transmission customers as well as utilities shall give their transmission requirement well in advance considering time required for implementation of the transmission assets. The transmission customers are also required to provide a reasonable basis for their transmission requirement such as - size and completion schedule of their generation facility, demand based on EPS and their commitment to bear transmission service charges.

3.5 Planning of transmission system for evacuation of power from hydro projects shall be done river basin wise considering the identified generation projects and their power potential.

3.6 In case of highly constrained areas like congested urban / semi-urban area, very difficult terrain etc., the transmission corridor may be planned by taking long term perspective of optimizing the right-of-way and cost. This may be done by adopting higher voltage levels for final system and operating one level below in the initial stage, or by using multi-circuit towers for stringing circuits in the future, or using new technology such as HVDC, GIS etc.

3.7 In line with Section 39 of the Electricity Act, the STU shall act as the nodal agency for Intra-STS planning in coordination with distribution licensees and intra-state generators connected/to be connected in the STU grid. The STU shall be the single point contact for the purpose of ISTS planning and shall be responsible on behalf of all the intra-State entities, for evacuation of power from their State's generating stations, meeting requirements of DISCOMS and drawing power from ISTS commensurate with the ISTS plan.

3.8 Normally, the various intra-State entities shall be supplied power through the intra-state network. Only under exceptional circumstances, the load serving intra-State entity may be allowed direct inter-connection with ISTS on recommendation of STU provided that such an entity would continue as intra-State entity for the purpose of all jurisdictional matters including energy accounting. Under such situation, this direct interconnection may also be used by other intra-State entity(s).

Further, State Transmission Utilities (STUs) shall coordinate with urban planning agencies, Special Economic Zone (SEZ) developers, industrial developers etc. to keep adequate provision for transmission corridor and land for new substations for their long term requirements.

3.9 The system parameters and loading of system elements shall remain within prescribed limits. The adequacy of the transmission system should be tested for different feasible load-generation scenarios as detailed subsequently in Paragraph: 9-11 of this manual.

3.10 The system shall be planned to operate within permissible limits both under normal as well as after more probable credible contingency(ies) as detailed in subsequent paragraphs of this manual. However, the system may experience extreme contingencies which are rare, and the system may not be planned for such rare contingencies. To ensure security of the grid, the extreme/rare but credible contingencies should be identified from time to time and suitable defense mechanism, such as - load shedding, generation rescheduling, islanding, system protection schemes, etc. may be worked out to mitigate their adverse impact.

3.11 The following options may be considered for strengthening of the transmission network. The choice shall be based on cost, reliability, right-of-way requirements, transmission losses, down time (in case of up-gradation and re-conductoring options) etc.

- Addition of new transmission lines/ substations to avoid overloading of existing system including adoption of next higher voltage.
- Application of Series Capacitors, FACTS devices and phase-shifting transformers in existing and new transmission systems to increase power transfer capability.
- Up-gradation of the existing AC transmission lines to higher voltage using same right-of-way.
- Re-conductoring of the existing AC transmission line with higher ampacity conductors.
- Use of multi-voltage level and multi-circuit transmission lines.
- Use of narrow base towers and pole type towers in semi-urban / urban areas keeping in view cost and right-of-way optimization.
- Use of HVDC transmission – both conventional as well as voltage source convertor (VSC) based.
- Use of GIS / Hybrid switchgear (for urban, coastal, polluted areas etc)

3.12 Critical loads such as - railways, metro rail, airports, refineries, underground mines, steel plants, smelter plants, etc. shall plan their interconnection with the grid, with 100% redundancy and as far as possible from two different sources of supply, in coordination with the concerned STU.

3.13 The planned transmission capacity would be finite and there are bound to be congestions if large quantum of electricity is sought to be transmitted in direction not previously planned.

3.14 Appropriate communication system for the new sub-stations and generating stations may be planned by CTU/STUs and implemented by CTU/STUs/generation developers so that the same is ready at the time of commissioning.

Criteria for steady-state and transient-state behavior (Paragraph 4 to 6)

4. General principles

The transmission system shall be planned considering following general principles:

4.1 In normal operation ('N-0') of the grid, with all elements to be available in service in the time horizon of study, it is required that all the system parameters like voltages, loadings, frequency should remain within permissible normal limits.

4.2 The grid may however be subjected to disturbances and it is required that after a more probable disturbance i.e. loss of an element ('N-1' or single contingency condition), all the system parameters like voltages, loadings, frequency shall be within permissible normal limits.

4.3 However, after suffering one contingency, grid is still vulnerable to experience second contingency, though less probable ('N-1-1'), wherein some of the equipments may be loaded up to their emergency limits. To bring the system parameters back within their normal limits, load shedding/re-scheduling of generation may have to be applied either manually or through automatic system protection schemes (SPS). Such measures shall generally be applied within one and a half hour(1½) after the disturbance.

5. Permissible normal and emergency limits

5.1 Normal thermal ratings and normal voltage limits represent equipment limits that can be sustained on continuous basis. Emergency thermal ratings and emergency voltage limits represent equipment limits that can be tolerated for a relatively short time which may be one hour to two hour depending on design of the equipment. The normal and emergency ratings to be used in this context are given below:

5.2 (a) The loading limit for a transmission line shall be its thermal loading limit. The thermal loading limit of a line is determined by design parameters based on ambient temperature, maximum permissible conductor temperature, wind speed, solar radiation, absorption coefficient, emissivity coefficient etc. In India, all the above factors and more particularly ambient temperatures in various parts of the country are different and vary considerably during various seasons of the year. However, during planning, the ambient temperature and other factors are assumed to be fixed, thereby permitting margins during operation. Generally, the ambient temperature may be taken as 45 deg Celsius; however, in some areas like hilly areas where ambient temperatures are less, the same may be taken. The maximum permissible thermal line loadings for different types of line configurations, employing various types of conductors, are given in Table-II of Annexure-V.

(b) Design of transmission lines with various types of conductors should be based on conductor temperature limit, right-of-way optimization, losses in the line, cost and reliability considerations etc.

(c) The loading limit for an inter-connecting transformer (ICT) shall be its name plate rating. However, during planning, a margin as specified in Paragraph: 13.2 and 13.3 shall be kept in the above lines/transformers loading limits.

(d) The emergency thermal limits for the purpose of planning shall be 110% of the normal thermal limits.

5.3 Voltage limits

a) The steady-state voltage limits are given below. However, at the planning stage a margin as specified at Paragraph: 13.4 may be kept in the voltage limits.

Voltages (kV_{rms})				
	Normal rating		**Emergency rating**	
Nominal	**Maximum**	**Minimum**	**Maximum**	**Minimum**
765	800	728	800	713
400	420	380	420	372
230	245	207	245	202
220	245	198	245	194
132	145	122	145	119
110	123	99	123	97
66	72.5	60	72.5	59

b) Temporary over voltage limits due to sudden load rejection:

i) 800kV system 1.4 p.u. peak phase to neutral (653 kV = 1 p.u.)

ii) 420kV system 1.5 p.u. peak phase to neutral (343 kV = 1 p.u.)

iii) 245kV system 1.8 p.u. peak phase to neutral (200 kV = 1 p.u.)

iv) 145kV system 1.8 p.u. peak phase to neutral (118 kV = 1 p.u.)

v) 123kV system 1.8 p.u. peak phase to neutral (100 kV = 1 p.u.)

vi) 72.5kV system 1.9 p.u. peak phase to neutral (59 kV = 1 p.u.)

c) Switching over voltage limits

i) 800kV system 1.9 p.u. peak phase to neutral (653 kV = 1 p.u.)

ii) 420kV system 2.5 p.u. peak phase to neutral (343 kV = 1 p.u.)

6. Reliability criteria

6.1 Criteria for system with no contingency (‘N-0’)

a) The system shall be tested for all the load-generation scenarios as given in this document at Paragraph: 9 -11.

b) For the planning purpose all the equipments shall remain within their normal thermal loadings and voltage ratings.

c) The angular separation between adjacent buses shall not exceed 30 degree.

6.2 Criteria for single contingency (‘N-1’)

6.2.1 Steady-state :

a) All the equipments in the transmission system shall remain within their normal thermal and voltage ratings after a disturbance involving loss of any one of the following elements (called single contingency or ‘N-1’ condition), but without load shedding / rescheduling of generation:

- Outage of a 132kV or 110kV single circuit,
- Outage of a 220kV or 230kV single circuit,
- Outage of a 400kV single circuit,
- Outage of a 400kV single circuit with fixed series capacitor(FSC),
- Outage of an Inter-Connecting Transformer(ICT),
- Outage of a 765kV single circuit
- Outage of one pole of HVDC bipole.

b) The angular separation between adjacent buses under (‘N-1’) conditions shall not exceed 30 degree.

6.2.2 Transient-state :

Usually, perturbation causes a transient that is oscillatory in nature, but if the system is stable the oscillations will be damped. The system is said to be stable in which synchronous machines, when perturbed, will either return to their original state if there is no change in exchange of power or will acquire new state asymptotically without losing synchronism. The transmission system shall be stable after it is subjected to one of the following disturbances:

a) The system shall be able to survive a permanent three phase to ground fault on a 765kV line close to the bus to be cleared in 100 ms.

b) The system shall be able to survive a permanent single phase to ground fault on a 765kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

c) The system shall be able to survive a permanent three phase to ground fault on a 400kV line close to the bus to be cleared in 100 ms.

d) The system shall be able to survive a permanent single phase to ground fault on a 400kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

e) In case of 220kV / 132 kV networks, the system shall be able to survive a permanent three phase fault on one circuit, close to a bus, with a fault clearing time of 160 ms (8 cycles) assuming 3-pole opening.

f) The system shall be able to survive a fault in HVDC convertor station, resulting in permanent outage of one of the poles of HVDC Bipole.

g) Contingency of loss of generation: The system shall remain stable under the contingency of outage of single largest generating unit or a critical generating unit (choice of candidate critical generating unit is left to the transmission planner).

6.3 Criteria for second contingency ('N-1-1')

6.3.1 Under the scenario where a contingency as defined at Paragraph: 6.2 has already happened, the system may be subjected to one of the following subsequent contingencies (called 'N-1-1' condition):

a) The system shall be able to survive a temporary single phase to ground fault on a 765kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and successful re-closure (dead time 1 second) shall be considered.

b) The system shall be able to survive a permanent single phase to ground fault on a 400kV line close to the bus. Accordingly, single pole opening (100 ms) of the faulted phase and unsuccessful re-closure (dead time 1 second) followed by 3-pole opening (100 ms) of the faulted line shall be considered.

c) In case of 220kV / 132kV networks, the system shall be able to survive a permanent three phase fault on one circuit, close to a bus, with a fault clearing time of 160 ms (8 cycles) assuming 3-pole opening.

6.3.2 (a) In the 'N-1-1' contingency condition as stated above, if there is a temporary fault, the system shall not loose the second element after clearing of fault but shall successfully survive the disturbance.

(b) In case of permanent fault, the system shall loose the second element as a result of fault clearing and thereafter, shall asymptotically reach to a new steady state without losing synchronism. In this new state the system parameters (i.e. voltages and line loadings) shall not exceed emergency limits, however, there may be requirement of load shedding / rescheduling of generation so as to bring system parameters within normal limits.

6.4 Criteria for generation radially connected with the grid

For the transmission system connecting generators or a group of generators radially with the grid, the following criteria shall apply:

6.4.1 The radial system shall meet 'N-1' reliability criteria as given at Paragraph: 6.2 for both the steady-state as well as transient-state.

6.4.2 For subsequent contingency i.e. 'N-1-1' (of Paragraph: 6.3) only temporary fault shall be considered for the radial system.

6.4.3 If the 'N-1-1' contingency is of permanent nature or any disturbance/contingency causes disconnection of such generator/group of generators from the main grid, the remaining main grid shall asymptotically reach to a new steady-state without losing synchronism after loss of generation. In this new state the system parameters shall not exceed emergency limits, however, there may be requirement of load shedding / rescheduling of generation so as to bring system parameters within normal limits.

Criteria for simulation and studies (Paragraph 7 to 13)

7. System studies for transmission planning

7.1 The system shall be planned based on one or more of the following power system studies, as per requirements:

i) Power Flow Studies

ii) Short Circuit Studies

iii) Stability Studies (including transient stability ** and voltage stability)

iv) EMTP studies (for switching / dynamic over-voltages, insulation coordination, etc)

(** Note : *The candidate lines, for which stability studies may be carried out, may be selected through results of load flow studies. Choice of candidate lines for transient stability studies are left to transmission planner. Generally, the lines for which the angular difference between its terminal buses is more than 20 degree after contingency of one circuit may be selected for performing stability studies.)*

8. Power system model for simulation studies

8.1 Consideration of voltage level

8.1.1 For the purpose of planning of the ISTS:

a) The transmission network may be modeled down to 220kV level with exception for North Eastern Region and parts of Uttrakhand, Himachal and Sikkim which may be modeled down to 132kV level.

b) The generating units that are stepped-up at 132kV or 110kV may be connected at the nearest 220kV bus through a 220/132 kV transformer for simulation purpose. The generating units smaller than 50 MW size within a plant may be lumped and modeled as a single unit, if total lumped installed capacity is less than 200 MW.

c) Load may be lumped at 220kV or 132kV/110kV, as the case may be.

8.1.2 For the purpose of planning of the Intra-STS System, the transmission network may be modeled down to 66kV level or up to the voltage level which is not in the jurisdiction of DISCOM. The STUs may also consider modeling smaller generating units, if required.

8.2 Time Horizons for transmission planning

8.2.1 Concept to commissioning for transmission elements generally takes three to five years; about three years for augmentation of capacitors, reactors, transformers etc., and about four to five years for new transmission lines or substations. Therefore, system studies for firming up the transmission plans may be carried out with 3-5 year time horizon.

8.2.2 Endeavour shall be to prepare base case models corresponding to load-generation scenarios (referred in Paragraph: 10 and 11) for a 5 year time horizon. These models may be tested applying the relevant criteria mentioned in this manual.

9. Load - generation scenarios

9.1 The load-generation scenarios shall be worked out so as to reflect in a pragmatic manner the typical daily and seasonal variations in load demand and generation availability.

10. Load demands

10.1 Active power (MW)

10.1.1 The system peak demands (state-wise, regional and national) shall be based on the latest Electric Power Survey (EPS) report of CEA. However, the same may be moderated based on actual load growth of past three (3) years.

10.1.2 The load demands at other periods (seasonal variations and minimum loads) shall be derived based on the annual peak demand and past pattern of load variations. In the absence of such data, the season-wise variation in the load demand may be taken as given in Table-III at Annexure-III.

10.1.3 While doing the simulation, if the peak load figures are more than the peaking availability of generation, the loads may be suitably adjusted substation-wise to match with the availability. Similarly, while doing the simulation, if the peaking availability is more than the peak load, the generation dispatches may be suitably reduced, to the extent possible, such that, the inter-regional power transfers are high.

10.1.4 From practical considerations the load variations over the year shall be considered as under:

a. Annual Peak Load

b. Seasonal variation in Peak Loads for Winter, Summer and Monsoon

c. Seasonal Light Load (for Light Load scenario, motor load of pumped storage plants shall be considered)

10.1.5 The sub-station wise annual load data, both MW and MVAr shall be provided by the State Transmission Utilities as per the format given at Annexure -IV.

10.2 Reactive power (MVAr)

10.2.1 Reactive power plays an important role in EHV transmission system planning and hence forecast of reactive power demand on an area-wise or substation-wise basis is as important as active power forecast. This forecast would obviously require adequate data on the reactive power demands at the different substations as well as the projected plans for reactive power compensation.

10.2.2 For developing an optimal ISTS, the STUs must clearly spell out the substation-wise maximum and minimum demand in MW and MVAr on seasonal basis in the format given at Annexure - IV. In the absence of such data the load power factor at 220kV and 132kV voltage levels may be taken as 0.95 lag during peak load condition and 0.98 lag during light load condition. The STUs shall provide adequate reactive compensation to bring power factor as close to unity at 132kV and 220kV voltage levels.

11. Generation dispatches and modeling

11.1 For the purpose of development of Load Generation scenarios on all India basis, the all India peaking availability may be calculated as per the norms given in Table-I and Table-II at Annexure-III.

11.2 For planning of new transmission lines and substations, the peak load scenarios corresponding to summer, monsoon and winter seasons may be studied. Further, the light load scenarios (considering pumping load where pumped storage stations exist) may also be carried out as per requirement.

11.3 For evolving transmission systems for integration of wind and solar generation projects, high wind/solar generation injections may also be studied in combination with suitable conventional dispatch scenarios. In such scenarios, the Intra-State generating station of the RES purchasing State may be backed-down so that impact of wind generation on the ISTS grid is minimum**. The maximum generation at a wind/solar aggregation level may be calculated using capacity factors as per the norms given in Table-II at Annexure - III.

***Note:*

1) *As per the grid code, it is the responsibility of each SLDC to balance its load and generation and stick to the schedule issued by RLDC. Accordingly, it follows that in case of variation in generation from Renewable Energy Source (RES) portfolio, the State should back-down/ramp-up its conventional (thermal/hydro) generation plants or revise their drawal schedule from ISGS plants and stick to the revised schedule. The Intra-State generating station should be capable of ramping-up/backing-down based on variation in RES generation so that impact of variability in RES on the ISTS grid is minimum.*
2) *Further to address the variability of the wind/solar projects, other aspects like reactive compensation, forecasting and establishment of renewable energy control centers may also be planned by STUs.*

11.4 Special area dispatches

a) Special dispatches corresponding to high agricultural load with low power factor, wherever applicable.

b) Complete closure of a generating station close to a major load centre.

11.5 In case of thermal units (including coal, gas/diesel and nuclear based) the minimum level of output (ex-generation bus, i.e. net of the auxiliary consumption) shall be taken as not less than 70% of the rated installed capacity. If the thermal units are encouraged to run with oil support, they may be modeled to run up to 25% of the rated capacity.

11.6 The generating unit shall be modeled to run as per their respective capability curves. In the absence of capability curve, the reactive power limits(Q_{max} and Q_{min}) for generator buses can be taken as :

a. Thermal Units : Q_{max} = 60% of P_{max}, and Q_{min} = (-) 50% of Q_{max}

b. Nuclear Units : Q_{max} = 60% of P_{max}, and Q_{min} = (-) 50% of Q_{max}

c. Hydro Units : Q_{max} = 48% of P_{max}, and Q_{min} = (-) 50% of Q_{max}

11.7 It shall be duty of all the generators to provide technical details such as machine capability curves, generator, exciter, governor, PSS parameters etc., for modeling of their machines for steady-state and transient-state studies, in the format sought by CTU/STUs. The CTU and STUs shall provide the information to CEA for preparation of national electricity plan.

12. Short circuit studies

12.1 The short circuit studies shall be carried out using the classical method with flat pre-fault voltages and sub-transient reactance (X''_d) of the synchronous machines.

12.2 MVA of all the generating units in a plant may be considered for determining maximum short-circuit level at various buses in system. This short-circuit level may be considered for substation planning.

12.3 Vector group of the transformers shall be considered for doing short circuit studies for asymmetrical faults. Inter-winding reactances in case of three winding transformers shall also be considered. For evaluating the short circuit levels at a generating bus (11kV, 13.8kV, 21kV etc.), the unit and its generator transformer shall be represented separately.

12.4 Short circuit level both for three phase to ground fault and single phase to ground fault shall be calculated.

12.5 The short-circuit level in the system varies with operating conditions, it may be low for light load scenario compared with for peak load scenario, as some of the plants may not be on-bar. For getting an understanding of system strength under different load-generation / export-import scenarios, the MVA of only those machines shall be taken which are on bar in that scenario.

13. Planning margins

13.1 In a very large interconnected grid, there can be unpredictable power flows in real time due to imbalance in load-generation balance in different pockets of the grid. This may lead to overloading of transmission elements during operation, which cannot be predicted in advance at the planning stage. This can also happen due to delay in commissioning of a few planned transmission elements, delay/abandoning of planned generation additions or load growth at variance with the estimates. Such uncertainties are unavoidable and hence some margins at the planning stage may help in reducing impact of such uncertainties. However, care needs to be taken to avoid stranded transmission assets. Therefore, at the planning stage following planning margins may be provided:

13.2 Against the requirement of Long Term Access sought, the new transmission lines emanating from a power station to the nearest grid point may be planned considering overload capacity of the generating stations in consultation with generators.

13.3 The new transmission additions required for system strengthening may be planned keeping a margin of 10% in the thermal loading limits of lines and transformers (refer Paragraph: 5.2, above). Further, the margins in the inter-regional links may be kept as 15%.

13.4 At the planning stage, a margin of about $\pm$ 2% may be kept in the voltage limits (as given at Paragraph: 5.3(a), above) and thus the voltages under load flow studies (for 'N-0' and 'N-1' steady-state conditions only) may be maintained within the limits given below:

Voltage (kV_{rms}) (after planning margins)		
Nominal	**Maximum**	**Minimum**
765	785	745
400	412	388
230	240	212
220	240	203
132	142	125
110	119	102
66	70	62

13.5 In planning studies all the transformers may be kept at nominal taps and On Load Tap Changer (OLTC) may not be considered. The effect of the taps should be kept as operational margin.

13.6 For the purpose of load flow studies at planning stage, the nuclear generating units shall normally not run at leading power factor. To keep some margin at planning stage, the reactive power limits (Q_{max} and Q_{min}) for generator buses may be taken as:

Type of generating unit	Q_{max}	Q_{min}
Nuclear units	Q_{max}= 0.50 x P_{max}	Q_{min}= (-)0.10 x P_{max}
Thermal Units (other than Nuclear)	Q_{max}= 0.50 x P_{max}	Q_{min}= (-)0.10 x P_{max}
Hydro units	Q_{max}= 0.40 x P_{max}	Q_{min}= (-)0.20 x P_{max}

Notwithstanding above, during operation, following the instructions of the System Operator, the generating units shall operate at leading power factor as per their respective capability curves.

Additional planning criteria and guidelines (Paragraph 14 to 20)

14. Reactive power compensation

14.1 Requirement of reactive power compensation like shunt capacitors, shunt reactors(bus reactors or line reactors), static VAr compensators, fixed series capacitor, variable series capacitor(thyristor controlled) or other FACTS devices shall be assessed through appropriate studies.

14.2 Shunt capacitors

14.2.1 Reactive Compensation shall be provided as far as possible in the low voltage systems with a view to meet the reactive power requirements of load close to the load points, thereby avoiding the need for VAr transfer from high voltage system to the low voltage system. In the cases where network below 132kV/220 kV voltage level is not represented in the system planning studies, the shunt capacitors required for meeting the reactive power requirements of loads shall be provided at the 132kV/220kV buses for simulation purpose.

14.2.2 It shall be the responsibility of the respective utility to bring the load power factor as close to unity as possible by providing shunt capacitors at appropriate places in their system. Reactive power flow through 400/220kV or 400/132kV or 220/132(or 66) kV ICTs, shall be minimal. Wherever voltage on HV side of such an ICT is less than 0.975 pu no reactive power shall flow down through the ICT. Similarly, wherever voltage on HV side of the ICT is more than 1.025 pu no reactive power shall flow up through the ICT. These criteria shall apply under the 'N-0' conditions.

14.3 Shunt reactors

14.3.1 Switchable bus reactors shall be provided at EHV substations for controlling voltages within the limits (defined in the Paragraph: 5.3) without resorting to switching-off of lines. The bus reactors may also be provided at generation switchyards to supplement reactive capability of generators. The size of reactors should be such that under steady state condition, switching on and off of the reactors shall not cause a voltage change exceeding 5%. The standard sizes (MVAr) of reactors are:

Voltage Level	Standard sizes of reactors (in MVAr)
400kV (3-ph units)	50, 63, 80 and 125 (rated at 420kV)
765kV (1-ph units)	80 and 110 (rated at 800kV)

14.3.2 Fixed line reactors may be provided to control power frequency temporary over-voltage(TOV) after all voltage regulation action has taken place within the limits as defined in Paragraph: 5.3(b) under all probable operating conditions.

14.3.3 Line reactors (switchable/ controlled/ fixed) may be provided if it is not possible to charge EHV line without exceeding the maximum voltage limits given in Paragraph: 5.3(a). The possibility of reducing pre-charging voltage of the charging end shall also be considered in the context of establishing the need for reactors.

14.3.4 Guideline for switchable line reactors: The line reactors may be planned as switchable wherever the voltage limits, without the reactor(s), remain within limits specified for TOV conditions given at Paragraph: 5.3(b).

14.4 Static VAr compensation (SVC)

14.4.1 Static VAr Compensation (SVC) shall be provided where found necessary to damp the power swings and provide the system stability under conditions defined in the Paragraph: 6 on ‘Reliability Criteria’. The dynamic range of static compensators shall not be utilized under steady state operating condition as far as possible.

15. Sub-station planning criteria

15.1 The requirements in respect of EHV sub-stations in a system such as the total load to be catered by the sub-station of a particular voltage level, its MVA capacity, number of feeders permissible etc. are important to the planners so as to provide an idea to them about the time for going in for the adoption of next higher voltage level sub-station and also the number of substations required for meeting a particular quantum of load. Keeping these in view the following criteria have been laid down for planning an EHV substation:

15.2 The maximum short-circuit level on any new substation bus should not exceed 80% of the rated short circuit capacity of the substation. The 20% margin is intended to take care of the increase in short-circuit levels as the system grows. The rated breaking current capability of switchgear at different voltage levels may be taken as given below:

Voltage Level		Rated Breaking Capacity
132 kV	-	25 kA / 31.5 kA
220 kV	-	31.5 kA / 40 kA
400 kV	-	50 kA / 63 kA
765 kV	-	40 kA / 50 kA

Measures such as splitting of bus, series reactor, or any new technology may also be adopted to limit the short circuit levels at existing substations wherever they are likely to cross the designed limits.

15.3 Rating of the various substation equipments shall be such that they do not limit the loading limits of connected transmission lines.

15.4 Effort should be to explore possibility of planning a new substation instead of adding transformer capacity at an existing substation when the capacity of the existing sub-station has reached as given in column (B) in the following table. The capacity of any single sub-station at different voltage levels shall not normally exceed as given in column (C) in the following table:

Voltage Level (A)	Transformer Capacity	
	Existing capacity (B)	Maximum Capacity (C)
765 kV	6000 MVA	9000 MVA
400 kV	1260 MVA	2000 MVA
220 kV	320 MVA	500 MVA
132 kV	150 MVA	250 MVA

15.5 While augmenting the transformation capacity at an existing substation or planning a new substation the fault level of the substation shall also be kept in view. If the fault level is low the voltage stability studies shall be carried out.

15.6 Size and number of interconnecting transformers (ICTs) shall be planned in such a way that the outage of any single unit would not over load the remaining ICT(s) or the underlying system.

15.7 A stuck breaker condition shall not cause disruption of more than four feeders for the 220kV system and two feeders for the 400kV system and 765kV system.

Note – In order to meet this requirement it is recommended that the following bus switching scheme may be adopted for both AIS and GIS and also for the generation switchyards:

220kV – ‘Double Main’ or ‘Double Main & Transfer’ scheme with a maximum of eight(8) feeders in one section

400kV and 765kV – ‘One and half breaker’ scheme

16. Additional criteria for wind and solar projects

16.1 The capacity factor for the purpose of maximum injection to plan the evacuation system, both for immediate connectivity with the ISTS/Intra-STS and for onward transmission requirement, may taken as given in Table-II at Annexure – III.

16.2 The 'N-1' criteria may not be applied to the immediate connectivity of wind/solar farms with the ISTS/Intra-STS grid i.e. the line connecting the farm to the grid and the step-up transformers at the grid station.

16.3 As the generation of energy at a wind farm is possible only with the prevalence of wind, the thermal line loading limit of the lines connecting the wind machine(s)/farm to the nearest grid point may be assessed considering 12 km/hour wind speed.

16.4 The wind and solar farms shall maintain a power factor of 0.98 (absorbing) at their grid inter-connection point for all dispatch scenarios by providing adequate reactive compensation and the same shall be assumed for system studies.

17. Additional criteria for nuclear power stations

17.1 In case of transmission system associated with a nuclear power station there shall be two independent sources of power supply for the purpose of providing start-up power. Further, the angle between start-up power source and the generation switchyard should be, as far as possible, maintained within 10 degrees.

17.2 The evacuation system for sensitive power stations viz., nuclear power stations, shall generally be planned so as to terminate it at large load centres to facilitate islanding of the power station in case of contingency.

18. GUIDELINES FOR PLANNING HVDC TRANSMISSION SYSTEM

18.1 The option of HVDC bipole may be considered for transmitting bulk power (more than 2000 MW) over long distance (more than 700 km). HVDC transmission may also be considered in the transmission corridors that have AC lines carrying heavy power flows (total more than 5000 MW) to control and supplement the AC transmission network.

18.2 The ratio of fault level in MVA at any of the convertor station (for conventional current source type), to the power flow on the HVDC bipole shall not be less than 3.0 under any of the load-generation scenarios given under Paragraph:9 to 11 and contingencies given at Paragraph: 6, above. Further, in areas where multiple HVDC bipoles are feeding power (multi in feed), the appropriate studies be carried at planning stage so as to avoid commutation failure.

19. Guidelines for voltage stability

19.1 Voltage Stability Studies: These studies may carried out using load flow analysis program by creating a fictitious synchronous condenser at critical buses which are likely to have wide variation in voltage under various operating conditions i.e. bus is converted into a PV bus without reactive power limits. By reducing desired voltage of this bus, MVAr generation/ absorption is monitored. When voltage is reduced to some level it may be observed that MVAr absorption does not increase by reducing voltage further instead it also gets reduced. The voltage where MVAr absorption does not increase any further is known as Knee Point of Q-V curve. The knee point of Q-V curve represents the point of voltage instability. The horizontal 'distance' of the knee point to the zero-MVAr vertical axis measured in MVAr is, therefore, an indicator of the proximity to the voltage collapse.

19.2 Each bus shall operate above Knee Point of Q-V curve under all normal as well as the contingency conditions as discussed above. The system shall have adequate margins in terms of voltage stability.

20. Guidelines for consideration of zone – 3 settings

20.1 In some transmission lines, the Zone-3 relay setting may be such that it may trip under extreme loading condition. The transmission utilities should identify such relay settings and reset it at a value so that they do not trip at extreme loading of the line. For this purpose, the extreme loading may be taken as 120% of thermal current loading limit and assuming 0.9 per unit voltage (i.e. 360 kV for 400kV system, 689 kV for 765kV system). In case it is not practical to set the Zone-3 in the relay to take care of above, the transmission licensee/owner shall inform CEA, CTU/STU and RLDC/SLDC along with setting (primary impendence) value of the relay. Mitigating measures shall be taken at the earliest and till such time the permissible line loading for such lines would be the limit as calculated from relay impedance assuming 0.95 pu voltage, provided it is permitted by stability and voltage limit considerations as assessed through appropriate system studies.

Annexure- I

DEFINITIONS

1. **Peak Load:** It is the simultaneous maximum demand of the system being studied under a specific time duration(e.g. annual, monthly, daily etc).

2. **Light Load:** It is the simultaneous minimum demand of the system being studied under a specific time duration(e.g. annual, monthly, daily etc).

3. **System Stability:** A stable power system is one in which synchronous machines, when perturbed, will either return to their original state if there is no change in exchange of power or will acquire new state asymptotically without losing synchronism. Usually the perturbation causes a transient that is oscillatory in nature, but if the system is stable the oscillations will be damped.

4. **Temporary over-voltages:** These are power frequency over-voltages produced in a power system due to sudden load rejection, single phase to ground faults, etc.

5. **Switching over-voltages:** These over-voltages generated during switching of lines, transformers and reactors etc. having wave fronts 250/2500 micro sec.

6. **Surge Impedance Loading:** It is the unit power factor load over a resistance line such that series reactive loss (I^2X) along the line is equal to shunt capacitive gain (V^2Y). Under these conditions the sending end and receiving end voltages and current are equal in magnitude but different in phase position.

Annexure - II

ABBREVIATIONS

AC	:	Alternating Current
CEA	:	Central Electricity Authority
CTU	:	Central Transmission Utility
D/c	:	Double Circuit
DISCOM	:	Distribution Company
EHV	:	Extra High Voltage
EMTP	:	Electro Magnetic Transient Program
EPS	:	Electric Power Survey
FACTS	:	Flexible Alternating Current Transmission System
HV	:	High Voltage
HVDC	:	High Voltage Direct Current
ICT	:	Inter-Connecting Transformer
ISGS	:	Inter-State Generating Station
ISTS	:	Inter State Transmission System
Intra-STS	:	Intra-State Transmission System
kA	:	kilo Ampere
km	:	kilo meter
kV	:	kilo Volt
ms	:	millisecond
MVA	:	Million Volt Ampere
MVAr	:	Mega Volt Ampere reactive
MW	:	Mega Watt
NR/WR/SR/ ER/NER	:	Northern / Western / Southern / Eastern/North Eastern Region (s)
NLDC	:	National Load Dispatch Centre
P, Q	:	P - Active Power, Q - Reactive Power
P_{max}, Q_{max}, Q_{min}	:	P_{max} – Maximum Active Power, Q_{max} – Maximum Reactive Power Supplied i.e. lagging, Q_{min} – Maximum Reactive Power Absorbed i.e. leading

POSOCO	:	Power System Operation Corporation
POWERGRID or PGCIL	:	Power Grid Corporation of India Limited
p u	:	per unit
RES	:	Renewable Energy Source
RLDC	:	Regional Load Dispatch Centre
S/c	:	Single Circuit
SLDC	:	State Load Dispatch Centre
STU	:	State Transmission Utility (Generally Transmission Company of the State)
SVC	:	Static VAr Compensation
X, Y, Z	:	X - Reactance, Y - Admittance, Z - Impedance

Annexure- III

GENERATION AND LOAD FACTORS

Table – I

(Generation Availability Factors – for conventional generation)**

Actual data, wherever available, should be used. In cases where data is not available the generation availability may be calculated using following factors:

(a) Thermal Generation

Sl. No.	Type of Generation	Availability Factor (at Peak Load)	Availability Factor (at Light Load)
1.	Nuclear	80 %	80 %
2.	Thermal (Coal based)	80 %	80 %
3.	Thermal (Lignite based)	78 %	78 %
4.	Gas based (CCGT type)	85 %	50 %
5.	Diesel / or Gas based (open cycle)	90 %	50 %

(b) Hydro Generation

Sl. No.	Season	Availability Factor (at Peak Load)	Availability Factor (at Light Load)
1.	Summer	70 %	40 %
2.	Monsoon	90 %	60 %
3.	Winter	50 %	10 %

- The above availability factors are net of auxiliary consumption and considering planned/forced outages.
- The above availability factors may be used for working out generation availability at State/Regional/National level.
- These factors are not for modeling dispatch from individual units; the dispatch from a unit can be modeled up to its maximum capacity (net of Auxiliary consumption).

Table- II

(Capacity Factors – for Renewable Energy Source (wind/solar) generation) **

Capacity factor, considering diversity in wind/solar generation, is the ratio of maximum generation available at an aggregation point to the algebraic sum of capacity of each wind machine / solar panel connected to that grid point. Actual data, wherever available, should be used. In cases where data is not available the Capacity factor may be calculated using following factors:

Voltage level/ Aggregation level	132kV / Individual wind/solar farm	220kV	400kV	State (as a whole)
Capacity Factor (%)	80 %	75 %	70 %	60 %

Table- III

(Region-wise Demand Factors for seasonal variation of load) **

Actual data, wherever available, should be used. In cases where data is not available following Region-wise factors for seasonal variation of peak and light load demand may be assumed:

Sl. No.	Season / Scenario	Region-wise Demand Factors (%)				
		NR	WR	SR	ER	NER
1.	Summer Peak Load (S-PL)	**100**	**95**	**98**	**100**	**100**
2.	Summer Light Load (S-LL)	70	70	70	70	70
3.	Monsoon Peak Load (M-PL)	**96**	**90**	**90**	**95**	**95**
4.	Monsoon Light Load (M-LL)	70	70	70	70	70
5.	Winter Peak Load (W-PL)	**95**	**100**	**100**	**95**	**95**
6.	Winter Light Load (W-LL)	70	70	70	70	70

(Where 100% is for the annual peak load of a region)

** - The above factors may be revised from time to time.

Annexure- IV

LOAD DATA FROM STUs

STUs to provide sub-station wise load data as per following format:

(Please refer to Paragraph: 8 and Paragraph: 10)

Sl. No.	Name of Substation	Voltage Level	Peak Load		Light Load	
			MW	MVAR	MW	MVAR

The STUs may provide above information/data at least once a year (preferably by 31st March of every year.

Annexure- V

DATA FOR TRANSMISSION PLANNING STUDIES

Table- I(a)

(Line parameters (per unit / km / circuit, at 100 MVA base)

Actual system data, wherever available, should be used. In cases where data is not available standard data given below can be assumed:

Voltage (kV)	Config.	Type of conductor	Ckt	Positive sequence			Zero sequence		
				R	X	B	R_0	X_0	B_0
765	Quad	ACSR Bersimis	S/C	1.951E-6	4.880E-5	2.35E-2	4.500E-5	1.800E-4	1.406E-2
765	Hexa	ACSR Zebra	D/C	2.096E-6	4.360E-5	2.66E-2	3.839E-5	1.576E-4	1.613E-2
400	Twin	ACSR Moose	S/C	1.862E-5	2.075E-4	5.55E-3	1.012E-4	7.750E-4	3.584E-3
400	Twin	ACSR Moose	D/C	1.800E-5	1.923E-4	6.02E-3	1.672E-4	6.711E-4	3.669E-3
400	Twin	ACSR Lapwing	S/C	1.230E-5	1.910E-4	6.08E-3	6.685E-5	7.134E-4	3.926E-3
400	Twin	ACSR Lapwing	D/C	1.204E-5	1.905E-4	6.08E-3	1.606E-4	6.651E-4	3.682E-3
400	Twin	Moose eq. AAAC	S/C	1.934E-5	2.065E-4	5.67E-3	1.051E-4	7.730E-4	3.660E-3
400	Triple	ACSR Zebra	S/C	1.401E-5	1.870E-4	5.86E-3	7.616E-3	6.949E-4	3.783E-3
400	Quad	ACSR Zebra	S/C	1.050E-5	1.590E-4	6.60E-3	5.708E-3	5.940E-4	4.294E-3
400	Quad	ACSR Bersimis	S/C	7.416E-6	1.560E-4	7.46E-3	4.031E-3	5.828E-4	4.854E-3
400	Quad	ACSR Moose	S/C	9.167E-6	1.580E-4	7.32E-3	1.550E-4	6.250E-4	4.220E-3
400	Quad	ACSR Moose	D/C	9.177E-6	1.582E-4	7.33E-3	1.557E-4	6.246E-4	4.237E-3
400	Quad	Moose eq. AAAC	S/C	9.790E-6	1.676E-4	6.99E-3	5.320E-3	6.260E-4	4.510E-3
220	Twin	ACSR Moose	S/C	4.304E-5	5.819E-4	1.98E-3	4.200E-4	2.414E-3	1.107E-3
220	Single	ACSR Zebra	S/C	1.440E-4	8.220E-4	1.41E-3	4.231E-4	2.757E-3	8.843E-4
220	Single	ACSR Drake	S/C	1.800E-4	8.220E-4	1.41E-3	6.1E-4	2.56E-3	8.050E-4
220	Single	ACSR Moose	S/C	1.547E-4	8.249E-4	1.42E-3	4.545E-4	2.767E-3	8.906E-4
220	Single	ACSR Kunda	S/C	1.547E-4	8.249E-4	1.42E-3	4.545E-4	2.767E-3	8.906E-4
220	Single	AAAC Zebra	S/C	1.547E-4	8.249E-4	1.42E-3	4.545E-4	2.767E-3	8.906E-4
132	Single	ACSR Panther	S/C	9.310E-4	2.216E-3	5.10E-4	2.328E-3	9.310E-3	
66	Single	ACSR Dog	S/C	3.724E-3	8.864E-3	1.28E-4			

Table- I(b)

For some new conductors** the resistance data (in Ω/km) for **Zebra equivalent** size is given in following Table. The reactance(X) and susceptance (B) values of line mainly depend on the tower configuration, and therefore the X and B values (in per unit / km / circuit) may be taken from Table I(a) above for similar configuration.

Name of Conductor	DC Resistance	AC Resistance values at different temperatures (in Ω/km)							
	20 ° C	20° C	75 ° C	85 ° C	95 ° C	120 ° C	150 ° C	175 ° C	200 ° C
ACSR	0.06868	0.6868	0.08479	0.0875	NA	NA	NA	NA	NA
AAAC	0.06921	0.0704	0.08541	0.08814	0.09093	NA	NA	NA	NA
TACSR	0.07560	0.07668	0.09315	0.09613	0.09912	0.10662	0.11565	NA	NA
AL59	0.07805	0.0791	0.09610	0.09918	0.10230	NA	NA	NA	NA
ACSS	0.08430	0.08527	0.10366	0.1070	0.11034	0.11872	0.12878	0.13718	0.14557
STACIR	0.08000	0.08105	0.09847	0.10163	0.10479	0.11274	0.12229	0.13025	0.13822
ACCC	0.05510	0.05656	0.06844	0.07062	0.07279	0.07821	0.08475	0.09021	NA

Table- I(c)

For some new conductors** the resistance data (in Ω/km) for **Moose equivalent** size is given in following Table. The reactance(X) and susceptance (B) values of line mainly depend on the tower configuration, and therefore the X and B values (in per unit / km / circuit) may be taken from Table I(a) above for similar configuration.

Name of Conductor	DC Resistance	AC Resistance values at different temperatures (in Ω/km)							
	20 ° C	20° C	75 ° C	85 ° C	95 ° C	120 ° C	150 ° C	175 ° C	200 ° C
ACSR	0.05552	0.05699	0.069	0.07112	NA	NA	NA	NA	NA
AAAC	0.05980	0.06116	0.074	0.07646	0.07882	NA	NA	NA	NA
TACSR	0.05460	0.05609	0.068	0.07001	0.07213	0.07753	0.08398	NA	NA
AL59	0.05070	0.05231	0.063	0.06518	0.06714	NA	NA	NA	NA
ACSS	0.05210	0.05368	0.065	0.06691	0.06896	0.07409	0.08023	0.08537	0.09057
STACIR	0.06820	0.06941	0.084	0.08689	0.08960	0.09636	0.10445	0.11124	0.11802
ACCC	0.04340	0.04527	0.055	0.05618	0.05788	0.06211	0.06720	0.07148	NA

Table- I(d)

Name of Conductor	DC Resistance	AC Resistance values at different temperatures (in Ω/km)							
	20 º C	20º C	75 º C	85 º C	95 º C	120 º C	150 º C	175 º C	200 º C
ACSR Bersimis	0.0419	0.04384	0.0527	0.05435	NA	NA	NA	NA	NA
AAAC Bersimis	0.0494	0.05104	0.06164	0.06358	0.06548	NA	NA	NA	NA
ACSR Lapwing	0.0383	0.0404	0.04844	0.04995	NA	NA	NA	NA	NA
ACSR Snowbird **	0.055	0.0565	0.06832	0.07049	NA	NA	NA	NA	NA

ACSR - Aluminum Conductor Steel Reinforced

AAAC - All Aluminum Alloy Conductor

TACSR - Thermal Alloy Conductor Steel Reinforced

ACSS - Aluminum Conductor Steel Supported

STACIR - Super Thermal Alloy Conductor, Invar Reinforced

ACCC - Aluminum Conductor Composite Core

AL 59 - Alloy conductor (of Aluminum, Magnesium and Silicon)

Table- II

(Thermal Loading Limits of Transmission Lines)

Actual system data, wherever available, should be used. In cases where data is not available standard data given below can be assumed. Data for some new conductors which are equivalent to ACSR Zebra/Moose are also given in following tables:

Conductor type and dimension	Ambient Temperature (ºC)	AMPACITY FOR Maximum Conductor Temperature (ºC)	
		65	75
ACSR PANTHER 210 sq mm	40	312	413
	45	244	366
	48	199	334
	50		311

Thermal Loading Limits for ACSR Zebra equivalent Conductors

Conductor Type (metallic area) and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)					
		65	**75**	**85**	**95**	**120**	**150**
ACSR Zebra (484 Sq.mm) Dia:28.62mm	40	473	643	769	**NA**	**NA**	**NA**
	45	346	560	703	**NA**	**NA**	**NA**
	48	240	503	661	**NA**	**NA**	**NA**
	50	128	462	631	**NA**	**NA**	**NA**
Conductor Type (metallic area) and Dimension	**Ambient Temperature (deg C)**	**AMPACITY FOR Maximum Conductor Temperature (deg C)**					
		65	**75**	**85**	**90**	**95**	**120**
AAAC (479.00 sq mm) Dia:28.42 mm	40	471	639	765	818	866	NA
	45	345	557	700	758	811	NA
	48	240	501	657	720	776	NA
	50	130	460	627	693	751	NA
Conductor Type (metallic area) and Dimension	**Ambient Temperature (deg C)**	**AMPACITY FOR Maximum Conductor Temperature (deg C)**					
		65	**75**	**85**	**90**	**95**	**120**
AL59 (383.00 sq mm) Dia:25.41 mm	40	440	590	702	750	793	NA
	45	329	516	643	696	743	NA
	48	240	466	605	661	711	NA
	50	154	429	578	637	689	NA
Conductor Type (metallic area) and Dimension	**Ambient Temperature (deg C)**	**AMPACITY FOR Maximum Conductor Temperature (deg C)**					
		85	**95**	**120**	**150**	**175**	**200**
TACSR (462.63 sq mm) Dia:27.93mm	40	730	826	1010	1173	NA	NA
	45	667	773	971	1142	NA	NA
	48	627	740	946	1124	NA	NA
	50	599	717	930	1111	NA	NA
Conductor Type (metallic area) and Dimension	**Ambient Temperature (deg C)**	**AMPACITY FOR Maximum Conductor Temperature (deg C)**					
		85	**95**	**120**	**150**	**175**	**200**
STACIR (419.39 sq mm) Dia:26.61mm	40	701	793	969	1124	1228	1318
	45	642	743	931	1094	1203	1296
	48	604	711	908	1076	1188	1283
	50	577	689	892	1064	1177	1274

Conductor Type (metallic area) and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)					
		85	95	120	150	175	200
ACSS (413.69 sq mm) Dia:26.40mm	40	682	771	942	1093	1193	1281
	45	625	722	905	1064	1169	1260
	48	587	691	882	1046	1154	1247
	50	561	67	867	1035	1144	1238

Conductor Type (metallic area) and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)					
		85	95	120	150	175	200
ACCC (588.30 sq mm) Dia:28.14 mm	40	853	965	1182	1374	1502	NA
	45	780	904	1136	1338	1472	NA
	48	733	865	1107	1316	1453	NA
	50	700	837	1088	1301	1440	NA

Thermal Loading Limits for ACSR Moose equivalent Conductors

Conductor Type (metallic area) and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)					
		65	75	85	95	120	150
ACSR Moose (597 Sq.mm) Dia:31.77mm	40	528	728	874	**NA**	**NA**	**NA**
	45	378	631	798	**NA**	**NA**	**NA**
	48	247	565	749	**NA**	**NA**	**NA**
	50	83	516	714	**NA**	**NA**	**NA**

Conductor Type (metallic area) and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)					
		65	75	85	90	95	120
AAAC (570.00 sq mm) Dia:31.05 mm	40	509	699	839	898	952	NA
	45	366	606	766	831	890	NA
	48	243	543	719	789	851	NA
	50	96	497	686	759	825	NA

Conductor Type (metallic area) and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)					
		65	75	85	95	120	150
AL59 (586.59 sq mm) Dia:31.50 mm	40	551	759	912	976	1035	NA
	45	395	658	832	904	968	NA
	48	260	589	781	857	926	NA
	50	94	539	745	825	896	NA

Conductor Type (metallic area) and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)					
		85	95	120	150	175	200
TACSR (596.90 sq mm) Dia:31.77mm	40	881	1001	1230	1433	NA	NA
	45	805	936	1182	1396	NA	NA
	48	755	895	1152	1372	NA	NA
	50	720	867	1132	1357	NA	NA

Conductor Type (metallic area) and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)					
		85	95	120	150	175	200
STACIR (483.85 sq mm) Dia:28.63 mm	40	772	874	1070	1244	1360	1461
	45	706	818	1028	1211	1333	1437
	48	663	783	1003	1191	1316	1423
	50	633	758	985	1178	1304	1413

Conductor Type (metallic area) and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)					
		85	95	120	150	175	200
ACSS (597 sq mm) Dia:31.77mm	40	902	1024	1258	1466	1606	1727
	45	823	957	1209	1428	1573	1699
	48	772	915	1178	1404	1554	1682
	50	736	886	1158	1388	1540	1670

Conductor Type (metallic area) and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)					
		85	95	120	150	175	200
ACCC (729.41 sq mm) Dia:31.55 mm	40	982	1115	1371	1599	1606	NA
	45	897	1043	1318	1557	1573	NA
	48	841	998	1284	1531	1554	NA
	50	802	966	1262	1514	1540	NA

Thermal Loading Limits for Snowbird conductor

ACSR SNOWBIRD							
Conductor Type and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)					
		65	75	85	95	120	150
ACSR Snowbird 552.23sq.mm Dia:30.57mm	40	529	726	870	NA	NA	NA
	45	382	630	795	NA	NA	NA
	48	256	565	746	NA	NA	NA
	50	110	517	712	NA	NA	NA

Thermal Loading Limits for Bersimis equivalent conductors

ACSR Bersimis								
Conductor Type and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)						
		65	75	85	95	120	150
ACSR Bersimis 724.69sq.mm Dia:35.04 mm	40	606	848	1024	NA	NA	NA
	45	423	732	933	NA	NA	NA
	48	256	653	874	NA	NA	NA
	50		594	833	NA	NA	NA
AAAC BERSIMIS							
Conductor Type and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)					
		65	75	85	90	95	120
AAAC Bersimis 766.86Sq.mm Dia:36 mm	40	562	788	953	1022	1085	NA
	45	388	679	868	945	1014	NA
	48	228	605	813	896	969	NA
	50		550	774	861	938	NA

Thermal Loading Limits for Lapwing conductor

ACSR LAPWING							
Conductor Type and Dimension	Ambient Temperature (deg C)	AMPACITY FOR Maximum Conductor Temperature (deg C)					
		65	75	85	95	120	150
ACSR Lapwing 863.47Sq.mm Dia:38.22 mm	40	635	899	1090	NA	NA	NA
	45	430	773	992	NA	NA	NA
	48	234	686	928	NA	NA	NA
	50		622	883	NA	NA	NA

The above data has been calculated based on following assumptions:

- Solar radiations = 1045 W/m^2.
- Wind Speed = 2 km/hour
- Absorption Coefficient = 0.8
- Emissivity Coefficient = 0.45
- Age > 1 year

Table-III

(Sag of conductor on Transmission Lines)

Indicative sag values for various types of conductors, assuming a ruling span of 400m and considering that tension for conductor is less than that for ACSR conductor, are given below:

For Zebra equivalent conductors:

Name of CONDUCTOR	Sag(in meter) at different temperatures				
	85 °C	95 °C	120 °C	150 °C	200 °C
ACSR	9.66	NA	NA	NA	NA
TACSR	8.11	8.3	8.78	9.36	NA
ACSS*	7.53	7.73	8.23	8.85	9.86
STACIR	8.71	8.95	9.09	9.27	9.57
ACCC	8.77	8.79	8.84	8.90	NA
AAAC	10.37	NA	NA	NA	NA
AL59	10.16	10.60	NA	NA	NA

For Moose equivalent conductors:

Name of CONDUCTOR	Sag(in meter) at different temperatures				
	85 °C	95 °C	120 °C	150 °C	200 °C
ACSR	13.26	N/A	N/A	N/A	N/A
TACSR	10.78	10.95	11.40	11.95	N/A
ACSS*	10.98	11.17	11.65	12.22	13.17
STACIR	11.47	11.84	12.22	12.41	12.72
ACCC	12.61	12.63	12.69	12.76	NA
AAAC	14.15	NA	NA	NA	NA
AL59	14.52	14.96	NA	NA	NA

* Workings of ACSS done under pre-tensioned condition of max Wind Load

Table- IV

(Transformer Reactance)

Actual system data, wherever available, should be used. In cases where data is not available standard data given below can be assumed:

Type of Transformer	Transformer reactance X_t (at its own base MVA)
Generator transformer (GT)	14 – 15 %
Inter-Connecting Transformer (ICT)	12.5 %

Data for Transient Stability Studies

Table- V

(Voltage and Frequency Dependency of Load)

Actual system data, wherever available, should be used. In cases where data is not available standard data given below can be assumed:

Load	**Voltage Dependency of the system loads**	**Frequency Dependency of the system loads**
Active loads (P)	$P = P_0 \left(V / V_0 \right)$	$P = P_0 \left(f / f_0 \right)$
Reactive loads (Q)	$Q = Q_0 \left(V / V_0 \right)^2$	Q can be taken as independent of frequency. However, if appropriate relationship is known, Q may also be simulated as dependent on frequency, on case to case basis.
(where P_o, Q_o, V_o and f_o are values at the initial system operating conditions)		

Table- VI (Modeling for Machines)

Actual system data, wherever available, should be used. In cases where data is not available standard data given below can be assumed:

Table- V(a) : 'Typical parameters for Thermal and Hydro Machines'

MACHINE PARAMETERS	MACHINE RATING (MW)				
	THERMAL				HYDRO
	800 (Mundra)	660 (Sipat-I)	500 (Simhadri-II)	210	200
Rated Voltage (kV)	26.00	24.00	21.00	15.75	13.80
Rated MVA	960.00	776.50	588.00	247.00	225.00
Inertia Constant (H)	4.50	4.05	4.05	2.73	3.50
Reactance					
Leakage (X_L)	0.18	0.188	0.147	0.18	0.16
Direct axis (X_d)	2.07	2.00	2.31	2.23	0.96
Quadrature axis (X_q)	2.04	1.89	2.19	2.11	0.65
Transient Reactance					
Direct axis (X'_d)	0.327	0.265	0.253	0.27	0.27
Quadrature axis (X'_q)	0.472	0.345	0.665	0.53	0.65
Sub-transient Reactance					
Direct axis (X''_d)	0.236	0.235	0.191	0.214	0.18
Quadrature axis (X''_q)	0.236	0.235	0.233	0.245	0.23
Open Circuit Time Const.					
Transient					
Direct axis (T'_{do})	8.60	6.20	9.14	7.00	9.70
Quadrature axis (T'_{qo})	1.80	2.50	2.50	2.50	0.50
Sub-transient					
Direct axis (T''_{do})	0.033	0.037	0.04	0.04	0.05
Quadrature axis (T''_{qo})	0.05	0.20	0.20	0.20	0.10

Table: V(b) - 'Typical parameters for Exciters'

Typical Parameters	Hydro	Thermal	
		< 210 MW	> 210 MW
Transdu. Time Const. (TR)	0.040	0.040	0.015
Amplifier gain (KA)	25 – 50	25 – 50	50 -200

Typical Parameters	Hydro	Thermal	
		< 210 MW	**> 210 MW**
Amplif.Time Const.(TA)	0.04 – 0.05	0.04 – 0.05	0.03 – 0.05
Regulator limiting voltage			
Maximum (VR_{max})	4.0	6.0	5.0
Minimum (VR_{min})	-4.0	-5.0	-5.0
Feedback signal			
Gain (KF)	0.01	0.01	0.01
Time Constant (TF)	1.00	1.00	1.00
Exciter			
Gain(KE)	1.0	1.00	1.00
Time Constant (TE)	0.7	0.3	0.3

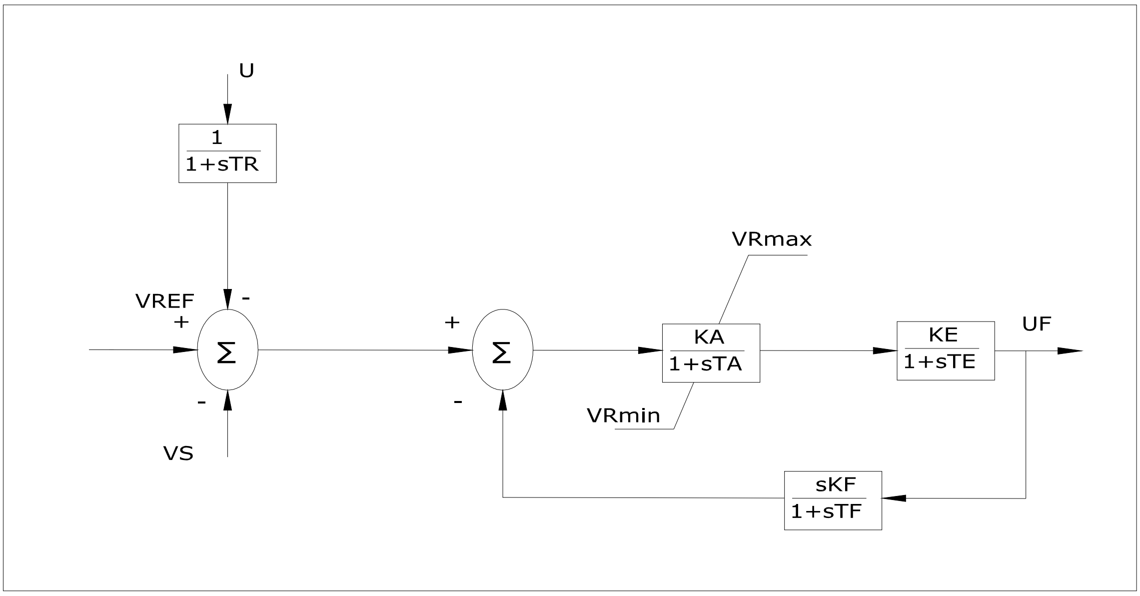
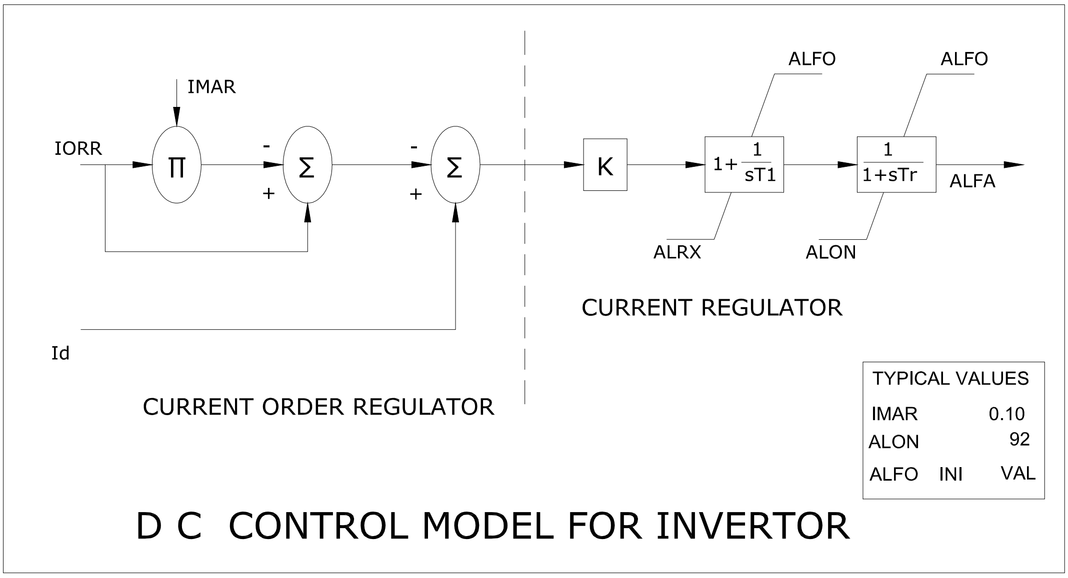
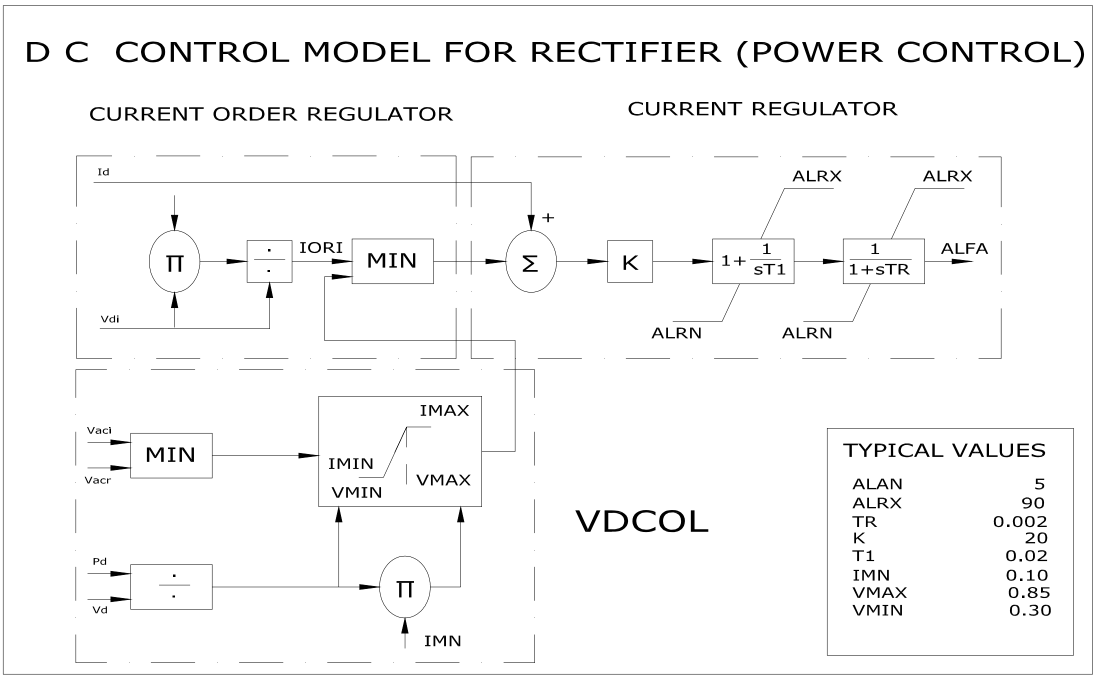


Table- VII (Modeling for HVDC)

Actual system data, wherever available, should be used. In cases where data is not available standard data given below can be assumed:

HVDC Data: No standardized DC control model has been developed so far as this model is usually built to the load requirements of the DC terminals. Based on the past experience in carrying out stability studies, the following models are suggested for Rectifier and Invertor terminals.





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Acknowledgement:

1. The drafting committee had the benefit of valuable inputs and suggestions from Shri S.K. Negi (MD, GETCO), Shri P. Sriramarao(Director(GO), APTRANSCO) and Shri NSM Rao (Suzlon).
2. The drafting committee thankfully acknowledges the comments and suggestions received from the following stakeholders:

APTRANSCO (Andhra Pradesh)	GETCO (Gujarat)
MSETCL (Maharashtra)	PSTCL(Punjab)
RVPN (Rajasthan)	MPPTCL (Madhya Pradesh)
TNEB (Tamil Nadu)	NTPC Ltd
PRDC (Consultant)	IEX (power exchange)
SUZLON (wind producer)	Sterlite Technologies
Jindal Power Ltd	Mr. A. Raja Rao, Bangalore
Mr. Mark B. Lively , USA	

3. The drafting committee also acknowledges the valuable suggestions, assistance and cooperation from Shri Siraj Bhattacharya(AGM) of Sterlite Technologies Ltd; Shri S.R. Narasimhan(DGM), Shri S.S. Barpanda(DGM) & Shri R.K. Porwal(CM) of NLDC; Shri Mukesh Khanna(DGM), Smt. Manju Gupta(DGM), Shri Rajil Srivastava(DGM) & Shri Anil Kumar Meena(Mgr.) of POWERGRID, and Shri Awdhesh K. Yadav (Dy. Dir.) & Smt. Manjari Chaturvedi (Dy. Dir.) of Central Electricity Authority.

Explanatory Notes

I. At the time of the earlier Transmission Planning Criteria, published in 1994, the Indian grid was in a developing stage with skeletal 400kV lines and no 765kV line. In the present criteria, the reliability requirements have been formulated considering growth of 400kV and 765kV network. For the 765kV level the earlier criteria required the system to be able to survive a temporary single phase to ground fault, and in the present criteria the system should be able to survive a permanent 3 phase fault with normal clearing (100 ms) or a permanent single phase to ground fault with dead time of one second. As regards steady state operation, the earlier manual on transmission planning, the criteria required secure operation of grid without necessitating generation rescheduling or load shedding following loss of one element i.e. 'N-1'. The manual was silent about subsequent fault. This has been elaborated by providing criteria for 'N-1-1'.

II. Inter-state and Intra-state transmission system and the dedicated lines are all interconnected and together constitute the transmission grid. The concept of dedicated line has come after the Electricity Act, 2003. The dedicated line allowed under Section 10 of the Act connects a generating station to the grid. There is a notion that since the dedicated line is a private line, the owner is free to plan and operate it as per his choice. The dedicated line operates as part of the integrated grid and affects the grid security like any other line. Therefore, for avoidance of doubt it has been mentioned at para 1.2 that the Transmission Planning Criteria shall also apply to the dedicated lines.

III. With the passage of time, getting R-o-W for transmission lines is becoming increasingly difficult. In the meanwhile a number of high capacity conductors have come to the market. They can be used to build new lines as well as for re-conductoring. They can be particularly useful in urban/semi urban areas, on multi-circuit towers, in hilly areas and even for normal usage. Comparative technical data (Resistance, Ampacity and Sag) has been tabulated in the Manual for easy selection.

IV. After the emergence of electricity market, there is an expectation that the planners should suo motu plan the expansion of the transmission system based on load forecast and generation development plans without waiting for the specific information to pour in. The above expectation is based on simplistic assumption that transmission system is similar to a plug and play device or an optic fibre backbone. The fact is that transmission system is a highly tailor made infrastructure. For instance, take the case of a 3000 MW hydro generation developer who has applied for connectivity to the CTU and is expecting the CTU to take care of its transmission needs. The fact is that no serious planning or implementation is possible simply by knowing the location of a large generation project. A 3000 MW project would require ±800 kV HVDC bi-pole from Arunachal Pradesh to the load centres in NR/WR/SR and would cost about Rs. 15,000 crore. Even on the basis of target region it would be too risky to build such an expensive system. Firm knowledge of the buying DISCOMs/States based on long term PPAs is a pre-requisite to decide the landing point of HVDC bi-pole and then to branch out to various firm buyers. Atleast 85% power should be tied up in long term PPAs at least five years in advance so that transmission can be properly planned and implemented. It has also to be realized that margins for short term open access are limited. This aspect has been highlighted in the preamble as well as at para 3.3 and 3.13.

V. For the reliability consideration, single contingency is the most probable grid event. Para 6.2 interalia specifies that after single contingency (N-1) resulting in outage of an element :

- the system will remain stable during transition
- there will be no need to readjust generation or load
- the elements of the depleted system shall remain within normal operating limits (current, voltage and angular separation)

The above shall apply to AC network, AC/DC hybrid network as well as to stand alone HVDC bi-poles and radial AC feeders. It may be clarified that if after N-1 contingency, generation/load has to be re-dispatched through special protection scheme or through manual intervention of the operator, it means that the system is not N-1 compliant. This requirement of N-1 compliance was also specified in the 1994 Manual. But this time it has been restated in a more elaborate manner. This is also in line with international practice. Feeders emanating from wind/solar farms and terminating at the grid pooling stations and transformers at the above pooling stations have been exempted from 'N-1' criteria. (Para 16.2).

VI. Para 6.3 provides that system should successfully pass through the transient state and remain stable in the event of a subsequent contingency (N-1-1). During the N-1-1 condition the system parameters should remain within emergency limits. The intervention of the operator may be required to bring the parameters back to the normal operating limits. Generating stations with radial double circuit lines or HVDC bi-poles connecting to the main grid may get separated in the event of N-1-1 contingency but the main grid should reach a new state after the separation. Further, corrective actions to normalize the grid frequency (such as load shedding through under frequency or df/dt relays, turbine governor response, SPS, activating spinning resources, activating load back down contracts etc.) fall in the realm of IEGC and the same have not been touched upon. Planning criteria for simulating 'N-1-1' contingency has been included to improve system reliability.

VII. To reduce the impact of uncertainties at the planning stage, i.e. deviation in actual growth of the power system (generation, load demand and transmission network) from the projected growth of power system known at the time of planning, some margins have been provided under para 13. The transmission system shall be planned keeping aside these margins. These planning margins may also improve reliability of the grid.

VIII. Criteria for providing dynamic compensation through Static Var Compensators in order to damp the power swings and to enhance system stability during disturbances has been included at para 14.4.

IX. In order to minimize the impact of stuck breaker condition, it has been specified that 400 kV and 765 kV substations shall have one and a half breaker switching scheme.

X. Additional planning criteria for wind and solar projects has been included at para 16.

XI. Guidelines for carrying out voltage stability studies have been added at para 19.

XII. Guidelines have been provided at para 20 so that the Zone 3 distance protection settings of transmission lines do not foul with thermal rating of the lines.

XIII. In the discussion paper published by CEA it was mentioned that :

"*The present planning criteria mentions the following for assessing permissible line loading limits :*

> *Permissible line loading limit depend on many factors such as voltage regulation, stability and current carrying capacity (thermal capacity) etc. While Surge Impedance Loading (SIL) gives a general idea of the loading capability of the line, it is usual to load the short lines above SIL and long lines lower than SIL (because of the stability limitations). SIL at different voltage levels is given at Annex – II. Annex –II also shows line loading (in terms of surge impedance loading of uncompensated line) as a function of line length assuming a voltage regulation of 5% and phase angular*

difference of 30^0 between the two ends of the line. In case of shunt compensated lines, the SIL will get reduced by a factor k, where

$$k = \sqrt{1 - \text{degree of compensation}}$$

For lines whose permissible line loading as determined from the curve higher than the thermal loading limit, permissible loading limit shall restricted to thermal loading limit ……………………..

The above methodology needs to be reviewed so as to incorporate assessment of line loadabilities through simulation studies instead of using thumb-rule based assessment using St. Clair curve (Annex II of the Manual). As fast system study /analysis software is available to planners and dispatcher (in comparison to the time when St. Clair curve was proposed in 1953), the appropriate simulation studies and analysis (load flow/ voltage stability / transient stability etc) can be used to allow line loadings up to thermal ampacity limit if permitted by stability and voltage regulation considerations. Therefore, it is proposed to drop the St. Clair curve as guiding criteria, and instead use the studies to check violation of thermal, voltage and stability criteria."

There was consensus on the proposal to dispense with St. Clair curve as a general guidance for transmission line loading. Instead, the transmission line loadings are required to be decided based on the studies which is also as per the international practice.

XIV. The machine data for 660 MW and 800 MW units required for simulation studies have been added.

XV. It has been specified at Para 3.14 that all new substations and generating stations should commission their communication systems along with the main facilities. SLDC/RLDC may disallow commissioning of the substation/ generating substations in case requisite communication system is not ready. The above provision has been added because effective communication system and telemetering are essential for secure grid operation.