Chapter 3 TRANSMISSION PLANNING

3.1 Power system data for transmission planning modelling

3.1.1 In order to precisely model the power system for planning studies, accuracy of data is very important, as the same can have considerable effect on outcome of system studies and ultimately on the system planning. The template data format in this regard is enclosed at Annexure-I, however, additional data may be required at the time of planning studies.

3.1.2 For ISTS planning, the transmission network may be modelled down to 220 kV level and wherever required such as for North Eastern Region, Uttarakhand, Himachal Pradesh and Sikkim, the transmission network may be modelled down to 132 kV level.

The generating units that are stepped-up at 132 kV may be connected at the nearest 220 kV 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 modelled as a single unit. Load may be lumped at 220 kV or 132 kV, as the case may be.

3.1.3 For Intra-STS planning, the transmission network may be modelled down to 66 kV level and lumping of generating units & loads may be considered accordingly. The STUs may consider modelling of smaller generating units if required.

3.1.4 For modelling of various elements, actual system data wherever available shall be used. In case where data is not available, standard data given in Annexure-II may be used.

3.2 Time Horizons for transmission planning

3.2.1 Concept to commissioning of transmission elements generally takes about three to five years; about two to three years for augmentation of capacitors, reactors, transformers etc., and about four to five years for new transmission lines or substations. Therefore, system studies for firming up the transmission plans may be carried out with 3-5 year time horizon on rolling basis every year. These studies may be tested by applying the relevant criteria mentioned in this manual.

3.3 Load - generation scenarios

3.3.1 The load-generation scenarios shall be worked out in a pragmatic manner so as to reflect the typical daily and seasonal variations in load demand and generation availability. Typical load generation scenario may include high/low

Wind, high/nil Solar, high/low Hydro generation, high demand, low demand and combinations thereof.

3.4 Loads

3.4.1 Active power (MW)

3.4.1.1 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 five (5) years.

3.4.1.2 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.

3.4.1.3 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, if the peaking availability is more than the peak load, the generation dispatches may be suitably reduced, to the extent possible considering merit order dispatch.

3.4.1.4 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

d) Variation of peak load in Region and time of day.

3.4.1.5 Actual demand data, wherever available, should be used. In cases where data is not available the load may be calculated using load factors given in Table-I of Annexure-III

3.4.2 Reactive power (MVAr)

3.4.2.1 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 (including existing, if any) for reactive power compensation.

3.4.2.2 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 absence of MVAR data, the load power factor shall be taken as per Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 and its amendments or re-enactment thereof. The STUs shall provide adequate reactive compensation to bring power factor as close to unity at 132 kV and 220 kV voltage levels.

3.4.2.3 Reactive power capability of generators including RE generators shall be as per provisions of Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 and its amendments or re-enactment thereof.

3.5 Generation dispatches and modelling

3.5.1 For the purpose of development of Load Generation scenarios on all India basis, the all India peaking availability may be calculated as per seasonal and daily variations based on the past pattern of generation variations.

3.5.2 For evolving transmission systems for integration of RE generation projects, high wind/solar generation injections may also be studied in combination with suitable conventional dispatch scenarios. In such scenarios, the generation of Intra-State generating station may be adjusted so that ISTS access of the state remain within the limits of General Network Access of the state. The maximum generation at a wind/solar aggregation level may be calculated using capacity factors as per the norms given in Table-II of Annexure - III.

3.6 Special area dispatches such as following may be considered in planning, wherever necessary:

a) Special dispatches corresponding to high agricultural load/lift irrigation pump schemes with low power factor, wherever applicable.

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

3.7 In case of coal based thermal power generating units, the minimum level of output (ex-bus generation, i.e. net of the auxiliary consumption) shall be taken as not less than 40% of the rated installed capacity.

3.8 The generating units shall be modelled to run as per their respective capability curves. In the absence of capability curve, the reactive power limits (Q_{max} and Q_{min}) for generating units can be taken as under:

Type of generating unit	**Q_{max}**	**Q_{min}**
Thermal units	$Q_{max} = 0.60 \times P_{max}$	$Q_{min} = (-)0.30 \times P_{max}$
Nuclear units	$Q_{max} = 0.50 \times P_{max}$	$Q_{min} = 0$
Hydro units	$Q_{max} = 0.48 \times P_{max}$	$Q_{min} = (-)0.24 \times P_{max}$
Wind / Solar / BESS	$Q_{max} = 0.33 \times P_{max}$	$Q_{min} = (-)0.33 \times P_{max}$

3.9 It shall be duty of all the generators to provide technical details of generating units, such as generator (including machine capability curves), exciter, governor, PSS parameters etc., for modelling of their machines for steady-state and transient-state studies. In case of Wind/Solar/BESS, equivalent generator model shall also be provided.

3.10 Planning margins

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

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

3.10.3 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. Further, the margins in the interregional links may be kept as 15%.

3.10.4 At the planning stage, a margin of about ± 2% may be kept in the voltage limits and thus the voltages under load flow studies (for ‘N-0’ and ‘N-1’ steady-state conditions only) may be maintained within the limits given below:

Voltage (kV_{rms}) (after planning margins)		
Nominal	**Maximum**	**Minimum**
765	785 (1.03 pu)	745 (0.97 pu)
400	412 (1.03 pu)	388 (0.97 pu)
230	240 (1.04 pu)	212 (0.92 pu)
220	240 (1.09 pu)	203 (0.92 pu)
132	142 (1.08 pu)	125 (0.95 pu)
110	119 (1.08 pu)	102 (0.93 pu)
66	70 (1.06 pu)	62 (0.94 pu)

3.10.5 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.

3.10.6 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 generating units may be taken as under:

Type of generating unit	Q_{max}	Q_{min}
Thermal Units	$Q_{max} = 0.50 \times P_{max}$	$Q_{min} = (-)0.10 \times P_{max}$
Nuclear units	$Q_{max} = 0.40 \times P_{max}$	$Q_{min} = 0$
Hydro units	$Q_{max} = 0.40 \times P_{max}$	$Q_{min} = (-)0.20 \times P_{max}$
Wind / Solar / BESS	$Q_{max} = 0.20 \times P_{max}$	$Q_{min} = (-)0.20 \times P_{max}$

Note: In case of limitation in Q_{max} and Q_{min}, similar ratio of margins as provided in Paragraph 3.8 and Paragraph 3.10, shall be considered for the generating unit with respect to capability curve.

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

3.11 System studies for transmission planning

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

i) Power Flow Studies

ii) Short Circuit Studies

iii) Stability Studies

iv) TTC/ATC Calculations

3.11.2 Additional studies as given below may be carried out at appropriate time as per requirement.

i) EMT studies

ii) Inertia studies

3.11.3 Details of the studies are discussed in subsequent paragraphs.

3.12 Power Flow studies

3.12.1 Load flow study is the steady state analysis of power system network. It determines the operating state of the system for a given load generation balance in the system. It helps in determination of loading on transmission elements and helps in planning and operation of power systems from steady state point of view.

3.12.2 All the elements of transmission network viz. transmission lines, transformers, generators, load, bus reactors, line reactors, HVDC, FACTS etc. are modelled using steady state parameters in the simulation software.

3.12.3 Load flow solves a set of simultaneous non-linear algebraic power equations for the two unknown variables ($|V|$ and $\angle\delta$) at each node in a system. The output of the load flow analysis is the voltage and phase angle, real and reactive power, losses and slack bus power.

3.12.4 The parameters calculated at Paragraph 3.12.3 above should be within the planning margins specified in Paragraph 3.10.

3.13 Short circuit studies

3.13.1 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.

3.13.2 For inverter based generators, the response of an inverter to grid disturbances is a function of the controls programmed into the inverter and the rated capability of the inverter. Wind / Solar / Hybrid plants need to clearly articulate how the inverter would behave during fault events to ensure that the correct response is provided during and immediately following fault conditions. In case of non-availability of data, sub-transient reactance (X''_d) for wind and solar generation may be assumed as 0.85 pu and 1 pu respectively for short circuit studies.

3.13.3 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.

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

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

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

3.14 Stability studies

3.14.1 Power System Stability may be broadly defined as property of a power system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after being subjected to a disturbance. Stability is a condition of equilibrium between opposing forces.

3.14.2 Rotor Angle Stability is the ability of interconnected synchronous machines of a power system to remain in synchronism. The stability problem involves the study of the electromechanical oscillations inherent in power system.

3.14.3 If the system is perturbed, this equilibrium is upset, resulting in acceleration or deceleration of the rotors of the machines according to the laws of motion of a rotating body. After perturbation, if one generator temporarily runs faster than another, the angular position of its rotor relative to that of the slower machine will advance. The resulting angular difference transfers part of the load from the slow machine to the fast machine, depending on the power-angle relationship. This tends to reduce the speed difference and hence the angular separation. The power-angle relationship is non-linear. Beyond a certain limit, an increase in angular separation is accompanied by a decrease in power transfer; this increases the angular separation further and leads to instability. For any given situation, the stability of the system depends on whether or not the deviations in angular positions of the rotors result in sufficient restoring torques.

3.14.4 In transient stability studies, the contingencies usually considered are short-circuits of different types: phase-to-ground, phase-to-phase-to-ground, or three phases to ground. They are usually assumed to occur on transmission lines, but occasionally bus or transformer faults are also considered. The fault is assumed to be cleared by the opening of appropriate circuit breakers to isolate the faulted element. In some cases, high-speed re-closure may be assumed.

3.14.5 In transient stability studies, the study period of interest is usually limited to 3 to 5 seconds following the disturbance, although it may extend to about 10 seconds for very large systems with dominant inter-area modes of oscillation.

3.14.6 During the analysis, impact due to tripping of one line of a radially connected generator may be studied.

3.14.7 Voltage stability is the ability of a power system to maintain steady acceptable voltages at all buses in the system under normal operating conditions and after being subjected to a disturbance. The system enters a state of voltage instability when there is disturbance/ increase in load demand / change in system condition which causes a progressive and uncontrollable drop in voltage. The main factor causing instability is the inability of the power system to meet the demand for reactive power. The heart of the problem is usually the voltage drop that occurs when active power and reactive power flow through inductive reactances associated with the transmission network.

3.14.8 A criterion for voltage stability is that, at a given operating condition for every bus in the system, the bus voltage magnitude increases as the reactive power injection at the same bus is increased. A system is voltage unstable if, for at least one bus in the system, the bus voltage magnitude (V) decreases as the reactive power injection (Q) at the same bus is increased. In other words, a system is voltage stable if V-Q sensitivity is positive for every bus and voltage unstable if V-Q sensitivity is negative for at least one bus.

3.14.9 Progressive drop in bus voltages can also be associated with rotor angles going out of step. In contrast, the type of sustained fall of voltage that is related to voltage instability occurs where rotor angle stability is not an issue.

3.14.10 Voltage instability is essentially a local phenomenon; however, its consequences may have a widespread impact. Voltage collapse is more complex than simple voltage instability and is usually the result of a sequence of events accompanying voltage instability, leading to a low-voltage profile in a significant part of the power system.

3.14.11 The candidate transmission elements for which stability studies may be carried out, may be selected through results of load flow studies. Choice of candidate transmission elements for stability studies are left to transmission planner.

3.14.12 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.

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

3.14.14 Each bus shall operate above Knee Point of Q-V curve under all normal as well as the contingency conditions detailed in Chapter-4. The system shall have adequate margins in terms of voltage stability.

3.15 TTC/ATC Calculation

3.15.1 "Total Transfer Capability (TTC)" means the electric power that can be transferred reliably over the inter-control area transmission system under a given set of operating conditions considering the effect of occurrence of the worst credible contingency as prescribed in reliability criteria in Chapter-4.

3.15.2 "Transmission Reliability Margin (TRM)" means the margin kept in the total transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in the system conditions. The TRM may be considered as minimum of 2% of demand of area/region or size of largest generating unit in that area/region.

3.15.3 "Available Transfer Capability (ATC)" means the transfer capability of the inter-control area transmission system available for scheduling commercial transactions in a specific direction, considering the reliability criteria. Mathematically ATC is the Total Transfer Capability Less Transmission Reliability Margin.

3.15.4 The studies to assess TTC, ATC and TRM of inter-regional or ISTS – Intra-STS transmission corridors for the future timeframe are to be carried out considering the load generation balance and planned transmission system.

3.15.5 While carrying out the studies, limiting condition on some portions of the transmission corridors may shift as the network operating conditions change over time. TTC would be the minimum of the transmission capability arrived at taking into consideration the Thermal, Voltage and Stability loading limits. TRM of the inter-regional corridor would be arrived at by considering the worst credible contingency.

3.15.6 The TTC, ATC and TRM values of transmission corridors may be revised due to change in system conditions, which includes change in network topology/change in anticipated Load-Generation balance for the future study timeframe.

3.15.7 Determination of ATC/TTC at planning stage:

3.15.7.1 Rated System Path (RSP) Method:

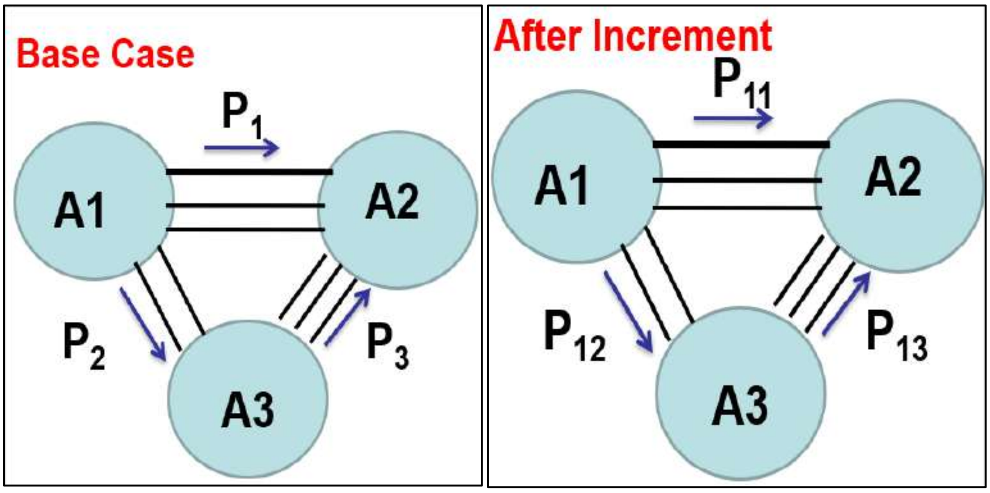
The RSP method for ATC calculation is typically used for transmission systems that are characterized by sparse networks. Generally in this approach, transmission paths between areas of the network are identified and based on simulation studies, individual transmission path capabilities are determined. It uses a maximum power flow test to ensure that the transfer path is capable of carrying power flows up to its rated transfer capability or TTC. When determined this way, the TTC rating usually remains fairly constant except for system configuration changes such as a line outage. However, this method is best suitable for a system which does not consist of meshed networks and there exist well-defined interfaces between them, or there are good controls on the flows of the paths.

3.15.7.2 Area Interchange method:

In this method the power transfer capability in terms of electric power transfer capability between areas are calculated. The presence of flow in parallel paths is taken in account. In this methodology, Load Generation balance is set. TTC is a function of total capacity availability on the most limiting transmission facility. To determine TTC, the Incremental Transfer Capability (ITC) is first determined. ITC is the measure, from a certain starting system condition, how much additional power can be transferred between the areas of interest before pre- or post-contingency limit(s) are reached. Once this ITC limit is found, it is combined with the existing transfers between the areas to come up with the total transfer capability between the areas based on simulation. However, the Incremental Transfer Capability (ITC) is dependent on the power flow between the areas through the parallel corridors.

3.15.7.3 Hybrid of both the above methodology can be adopted to capture the advantages of both methods to arrive at the optimum ATC value. The base case is established considering all network access. On this base value incremental values are calculated. In this method, maximum power transfer between two areas of interest says A_1 to A_2 are determined and the incremental flows both on the direct and parallel paths are noted. Incremental flow on A_1 to A_2 is P_{11} minus P_1. Similar values are determined for power transfer between area A_3 and A_2.

Now the total power transfer to A_2 is to happen simultaneously from both A_1 and A_3. TTC between A_1 & A_2 is calculated on base case Power transfer as per load generation balance between A_1 & A_2 plus minimum of ITC between A_1 & A_2 determined by above two conditions. Similar calculations are done transfer of power from A_3 to A_2.



3.16 EMT studies

3.16.1 Electro Magnetic Transient (EMT) study simulate electromagnetic, electromechanical and control system transient on multiphase electric power system.

3.16.2 EMT represents the power system and its control system by their differential equations. The solution of these equations is obtained in time domain. The response of the power system to any disturbance can be obtained at any frequency. Typically Temporary Over Voltage, Switching Over Voltage, Ferro resonance, Sub-Synchronous Resonance, Insulation Coordination etc. are performed under EMT studies.

3.16.3 During EMT studies transmission elements viz. transmission line, transformer/reactor, Generator, Circuit Breaker, Lightning Arrester, FACTS, etc. are modelled in detail. The equivalent grid is modelled as a constant voltage source behind an impedance. The switching sequence of the model under study is carried out as per requirement of TOV the study analysis.

3.16.4 Temporary Over Voltage (TOV): TOVs are undamped or little damped power-frequency overvoltages of relatively long duration (i.e., seconds, even minutes). They are often preceded by a transient overvoltage resulting from a switching operation, sudden load rejection, single line to ground fault etc. in a no / lightly loaded system. EMT studies provides to characterize TOV, determine resulting problems, and evaluate mitigation alternatives.

3.16.5 Switching Over Voltage: When a circuit breaker of an overhead transmission line is closed and line is energised, some switching transients are generated in the power system. Lightning and switching are two primary causes of transient overvoltage in power systems. Switching transients are an important factor in the equipment selection, protection and conductor clearances. Transmission Line Models with frequency dependent parameters are usually used for accurate modelling of EHV lines during switching overvoltage evaluation.

3.16.6 Sub-Synchronous Resonance (SSR): Generally, the series compensated transmission lines may cause SSR in the turbine generators, such that it leads to the electrical instability at sub synchronous frequencies resulting in turbine-generator shaft failures.

3.16.7 Insulation Coordination: Insulation Coordination is a method /procedure to select the dielectric strength of equipment vis-à-vis operating voltages and transient over-voltages which may appear on the system for which the equipment is designed / intended to operate.

3.16.8 Ferro resonance:

3.16.8.1 Ferro resonance is a general term applied to a wide variety of interactions between capacitors and iron-core inductors that result in unusual voltages and/or currents. In linear circuits, resonance occurs when the capacitive reactance equals the inductive reactance at the frequency at which the circuit is driven. Iron-core inductors have a non-linear characteristic and have a range of inductance values. Therefore, there may not be a case where the inductive reactance is equal to the capacitive reactance, but yet very high and damaging overvoltage occurs.

3.16.8.2 In power system, Ferro resonance occurs when a nonlinear inductor is fed from a series capacitor. The nonlinear inductor in power system can be due to: a) The magnetic core of a wound type voltage transformer, b) Bank type transformer, c) The complex structure of a 3 limb three-phase power transformer (core type transformer), d) The complex structure of a 5 limb three-phase power transformer (shell-type transformer).

3.16.8.3 Power transformers, under no-load or light-load conditions, are prone to be driven into Ferro resonance when energized through a long overhead lines or series compensated (FSC/TCSC) lines or underground cable (capacitive connection). Power transformer connected to a de-energized transmission line running in parallel with energized line can also drive the power transformer into Ferro resonance.

3.16.8.4 From the HVDC point of view, Ferro resonance should be eliminated to avoid unnecessary protective actions due to high levels of harmonic distortion.

3.16.8.5 Therefore, system study for Ferro-resonance may be carried out for the selective location such as line with series capacitance and lightly loaded transformers etc.

3.17 Inertia

3.17.1 Inertia is the property which resists change in its existing state. In power system, it refers to the energy stored in large rotating generators, which gives them the tendency to remain rotating. Inertia plays an important role in arresting the frequency drop during contingencies. In the grid, it gives the system operator a chance to respond to power plant failures giving other systems time to respond and rebalance supply and demand.

3.17.2 With the high penetration of renewable energy sources like wind and solar power and gradual reduction/decommissioning of conventional generators, total system inertia of grid would decline. However, Battery Energy Storage Systems (BESS), Synchronous Condenser etc. can provide fast response to arrest the frequency decline and help restore the frequency.

3.17.3 Determination of system inertia is essential for frequency stability assessment. Studies for assessing the system inertia would require modelling of individual generators including Wind / Solar plants. Data for the same has to be provided by generating companies.

3.17.4 The rate of change of frequency (RoCoF, in Hertz per second or Hz/s) shall be calculated based on simulation studies for the lowest inertia period (usually the highest RE penetration period or lowest demand period).

Following contingencies may be considered for the RoCoF calculation purpose

- Generation Contingency: The largest generating station including RE in the system or the station whose loss produces the highest RoCoF.
- Load Contingency: The largest load in the system (generally an industrial load).
- Determine whether the calculated RoCoF is lower than the maximum permissible RoCoF value.
- The maximum permissible RoCoF shall be such that the 1st stage UFLS doesn't get triggered and frequency remains 0.1 Hz above 1st stage of UFLS.

Chapter 4 CRITERIA FOR CONTINGENCY

4.1 General Principles

The transmission system shall be planned considering following general principles:

4.1.1 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.

4.1.2 The grid may however be subjected to outage / loss of an element and it is required that after loss of an element ('N-1' or single contingency), all the system parameters like voltages, loadings, frequency shall be within permissible normal limits.

4.1.3 Under outage / loss of an element, the grid may experience another contingency, though less probable ('N-1-1'), wherein some of the equipment may be loaded up to their emergency limits. To bring the system parameters back within their normal limits, load shedding/re-scheduling of generation may have to be done, either manually or through automatic system protection schemes (SPS). Such measures shall generally be applied within one hour after the disturbance.

4.2 Permissible normal and emergency limits

4.2.1 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 hours, depending on design of the equipment. The normal and emergency ratings to be used in this context are given in subsequent paragraphs.

4.2.2 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-II.

4.2.3 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.

4.2.4 The loading limit for an inter-connecting transformer (ICT) shall be its name plate rating.

4.2.5 During planning, a margin as specified in Paragraph: 3.10 shall be kept in the above lines/transformers loading limits.

4.2.6 The emergency thermal limits for the purpose of planning shall be 120% of the normal thermal limits for one hour and 110% of the normal thermal limits for two hours.

4.2.7 In real time system operation, capacity of transmission line may be assessed through Dynamic Line Loading, however, this may not be used while transmission system planning.

4.3 Voltage limits

a) The steady-state voltage limits are given below. However, at the planning stage a margin as specified at Paragraph: 3.10 may be kept in the voltage limits.

Voltages (kV_{rms})				
	Normal rating		Emergency rating	
Nominal	**Maximum**	**Minimum**	**Maximum**	**Minimum**
765 (1 pu)	800 (1.05 pu)	728 (0.95 pu)	800 (1.05 pu)	713 (0.93 pu)
400 (1 pu)	420 (1.05 pu)	380 (0.95 pu)	420 (1.05 pu)	372 (0.93 pu)
230 (1 pu)	245 (1.07 pu)	207 (0.90 pu)	245 (1.07 pu)	202 (0.88 pu)
220 (1 pu)	245 (1.11 pu)	198 (0.90 pu)	245 (1.11 pu)	194 (0.88 pu)
132 (1 pu)	145 (1.10 pu)	122 (0.92 pu)	145 (1.10 pu)	119 (0.90 pu)
110 (1 pu)	123 (1.12 pu)	99 (0.90 pu)	123 (1.12 pu)	97 (0.88 pu)
66 (1 pu)	72.5 (1.10 pu)	60 (0.91 pu)	72.5 (1.10 pu)	59 (0.89 pu)

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

i) 800 kV system 1.4 p.u. peak phase to neutral (653 kV = 1 p.u.)
ii) 420 kV system 1.5 p.u. peak phase to neutral (343 kV = 1 p.u.)
iii) 245 kV system 1.8 p.u. peak phase to neutral (200 kV = 1 p.u.)
iv) 145 kV system 1.8 p.u. peak phase to neutral (118 kV = 1 p.u.)
v) 123 kV system 1.8 p.u. peak phase to neutral (100 kV = 1 p.u.)
vi) 72.5 kV system 1.9 p.u. peak phase to neutral (59 kV = 1 p.u.)

c) Switching over voltage limits:

i) 800 kV system 1.9 p.u. peak phase to neutral (653 kV = 1 p.u.)
ii) 420 kV system 2.5 p.u. peak phase to neutral (343 kV = 1 p.u.)

4.4 Reliability criteria

4.4.1 No contingency ('N-0')

a) The system shall be tested for all the load-generation scenarios as given in this document at Paragraph 3.3.

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

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

4.4.2 Single contingency ('N-1')

4.4.2.1 Steady-state:

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

- Outage of a 132 kV single circuit,
- Outage of a 220 kV single circuit,
- Outage of a 400 kV single circuit (with or without fixed series capacitor),
- Outage of an Inter-Connecting Transformer (ICT) / power transformer,
- Outage of a 765 kV single circuit
- Outage of one pole of HVDC bipole

b) The angular separation between adjacent buses under 'N-1' shall not exceed 30 degree.

c) 'N-1' criteria for FACTS devices may not be considered, however studies may be carried out to address the issues like reduction in transfer capability, restriction on generation evacuation etc. in case of outage of FACTS devices.

4.4.2.2 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 outage / loss:

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

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

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

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

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

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

h) Loss of largest radial load, connected at single point.

4.4.3 Second contingency ('N-1-1')

4.4.3.1 Under the scenario as defined at Paragraph 4.4.2 the system may experience another contingency (called 'N-1-1'):

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

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

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

4.4.3.2 In the 'N-1-1' as stated above, if there is a temporary fault, the system shall not lose the second element after clearing of fault but shall successfully survive the disturbance.

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

4.4.4 **Radially connected generation with the grid**

For the transmission system connecting generator(s) radially with the grid, the following criteria shall apply:

4.4.4.1 The radial system shall meet 'N-1' reliability criteria as given at Paragraph 4.4.2 for both the steady-state as well as transient-state.

4.4.4.2 For subsequent contingency i.e. 'N-1-1' (as given at Paragraph 4.4.3), only temporary fault shall be considered for the radial system.

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

4.4.5 The 'N-1' criteria may not be applied to the immediate connectivity system of renewable generations with the ISTS/Intra-STS grid i.e. the line connecting the generation project switchyard to the grid and the step-up transformers at the grid station.

Provided that, 'N-1' criteria shall be applicable in case of renewable generation projects with storage, which are firm in nature and fully dispatchable.

Provided that, 'N-1' reliability criteria may be considered for ICTs at the ISTS / STU pooling stations for renewable energy based generation of more than 1000 MW after considering the capacity factor of renewable generating stations.

Chapter 5 SUBSTATION CRITERIA

5.1 General criteria

5.1.1 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 EHV substation planning criteria have been laid down in this Chapter.

5.1.2 There may be need for upgradation of the system or renovation and modernization of the existing system depending on technological options and system studies. Therefore, transmission licensee shall provide details to CEA/CTU/STUs of the transmission equipment which are required to be upgraded or for which renovation and modernization needs to be carried out.

5.1.3 As far as possible, an incoming and an outgoing feeder of same voltage level in a substation may be terminated in bays of same diameter in one and half breaker switching scheme, so as to make direct connection in case of outage of the substation, especially in case of Loop-in Loop-out of existing line(s).

5.1.4 Line approaching substation shall normally be perpendicular to the substation boundary for a stretch of 2-3 km.

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

Voltage Level	Rated Breaking Capacity
765 kV	50 kA / 63 kA
400 kV	63 kA / 80 kA
220 kV	40 kA / 50 kA / 63 kA
132 kV	25 kA / 31.5 kA / 40 kA
66kV	31.5 kA

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

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

5.1.7 Connection arrangement of switchable line reactors shall be such that it can be used as line reactor as well as bus reactor with suitable NGR bypass arrangement.

5.2 Transformers

5.2.1 Sub-stations may be classified into two categories i.e. (i) Load Serving Sub-station (LSS); where loads are connected (ii) Generation Pooling Sub-station (GPS); where generating stations are connected directly or through dedicated transmission line for evacuation of their power.

Provided that the substations where both generator(s) and load(s) are connected, shall be treated as load serving sub-station.

5.2.2 The capacity of any single sub-station at different voltage levels shall not normally exceed as given in column (B) and (C) in the following table:

Voltage Level (A)	Transformation Capacity	
	Load Serving Substation (B)	Generation Pooling substations (C)
765 kV	9000 MVA	9000 MVA
400 kV	2500 MVA	5000 MVA
220 kV	1000 MVA	1000 MVA
132 kV	500 MVA	500 MVA
66 kV	160 MVA	160 MVA

5.2.3 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

Provided that for immediate connectivity of RE plants, Paragraph 4.4.5 may be referred.

5.2.4 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.

5.3 Bus- Sectionalisation

5.3.1 To have minimum disruption during struck breaker condition, the bus switching scheme provided in Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2022 and its amendments or re-enactment thereof shall be implemented.

5.3.2 Sources and loads should be mixed in each diameter to maximize reliability in ‘one and half breaker scheme’ during planning of a new substation. Hence, one double circuit line consisting of two numbers feeders and originating from a transmission or generating switchyard shall not be terminated in one diameter. Similarly, termination of two numbers of transformers of identical primary voltage rating in one diameter of ‘one and half breaker scheme’ shall be avoided so that sudden outage is minimized. Layout and bus switching scheme of a