भारत सरकार
Government of India
विद्युत मंत्रालय
Ministry of Power
केंद्रीय विद्युत प्राधिकरण
Central Electricity Authority
विद्युत प्रणाली योजना एवं मूल्यांकन प्रभाग-II
Power System Planning & Appraisal Division-II

सेवा में / To,

(All Stakeholders in Power Sector)

विषय / Subject: Notice inviting suggestions / comments on Draft Manual on Transmission Planning Criteria – reg.

महोदय /Sir,

The Central Electricity Authority (CEA) is responsible for coordinating the activities of planning agencies as provided under Section 73(a) of the Electricity Act 2003.

For optimal development of transmission system in the country, CEA has brought the Manual on Transmission Planning Criteria in 1985, which was revised in 1994 and 2013. Considering large scale renewable energy integration, growth of load, increasing fault level, right of way issues, technical advancements, notification of Transmission Rules, etc. the Manual on Transmission Planning Criteria is proposed to be revised. Accordingly, the draft Central Electricity Authority (Manual on Transmission Planning Criteria), 2022 covering the planning philosophy, the information required from various entities, permissible limits, reliability criteria, broad scope of system studies, modelling and analysis etc. and gives guidelines for transmission planning has been prepared and enclosed herewith.

All stakeholders in Power Sector are hereby requested to kindly send their views/suggestions (if any) on the draft Manual on Transmission Planning Criteria to CEA by 30th June 2022 in the address given below, so that same could be appropriately considered while finalizing the Manual.

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भवदीय/Yours faithfully,

रवीन्द्र गुप्ता 16/6/22

(रवीन्द्र गुप्ता / Ravinder Gupta)
मुख्य अभियंता/ Chief Engineer

DRAFT MANUAL ON TRANSMISSION PLANNING CRITERIA

June, 2022

CENTRAL ELECTRICITY AUTHORITY
New Delhi

CONTENTS

Chapter 1 INTRODUCTION

1.1 Background

1.1.1 As per the Seventh Schedule to the Constitution of India, the subject electricity is in Concurrent List. This implies that both central and state governments play key roles, and can regulate and operate in the electricity sector. Accordingly, electricity transmission system in India is generally categorised as Inter-State Transmission System (ISTS) and Intra-State Transmission System (In-STS). Optimum development of transmission system requires coordinated planning of the Inter- State Transmission Systems (ISTS) and Intra-State Transmission Systems (In-STS). CEA is coordinating transmission planning process under section 73(a) of the Electricity Act 2003.

1.1.2 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 considering the experience gained on EHV systems. Technological advancements and institutional changes necessitated review of Transmission Planning Criteria. The regional electrical grids of Northern, Western, Southern, Eastern and North-Eastern regions have been synchronously interconnected to form one of the largest synchronous electrical grid 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.

1.1.3 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, among others. 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 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".

1.1.4 As the National grid grew in size and complexity, grid security was required to be enhanced considering large scale integration of renewable energy sources. Therefore, the transmission planning criteria was reviewed again in the year 2013.

1.1.5 Ministry of Power have promulgated Electricity (Transmission System Planning, Development and Recovery of Inter-State Transmission Charges) Rules, 2021 in Gazette of India on 01 .10.2021 paving the way for complete overhauling of transmission system planning to give power sector utilities easier access to electricity transmission network across the country. These Rules underpin that electricity transmission planning shall be done in such way that the lack of availability of the transmission system does not act as a barrier on the growth of different regions and the transmission system shall, as far as possible, be planned and developed matching with growth of generation and load. While doing the transmission planning, care shall be taken that there is no wasteful investment. These rules also introduced General Network Access (GNA) in the inter-state transmission system.

1.1.6 In view of above, there was need to update the Manual on Transmission Planning Criteria issued by CEA in January, 2013 especially in context with anticipated large scale renewable generation addition, growth of load, increasing fault level, right of way issues, technological advancement and notification of Transmission Rules 2021. Accordingly, the planning criteria has been revised again. This planning criteria may be referred as Central Electricity Authority (Manual on Transmission Planning Criteria), 2022.

1.2 Scope

1.2.1 The Central Electricity Authority is responsible for preparation of perspective generation and transmission plans and for coordinating the activities of planning agencies as envisaged 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 (In-STS). The ISTS and In-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.

1.2.2 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 (In-STS) down to 66kV level, including the dedicated transmission lines.

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

1.3 Applicability

1.3.1 These planning criteria shall be applicable from the date it is issued by Central Electricity Authority i.e. DD MMM 2022.

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

1.3.3 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 existing system. Till implementation of the additional system, suitable defence mechanisms may be put into place.

Chapter 2 PLANNING PHILOSOPHY

2.1 General guidelines

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

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

2.1.3 The principle for planning of the ISTS shall be to ensure that it is available as per the requirements of the States and the generators, as reflected by their General Network Access (GNA) requests. As far as possible, the transmission system shall be planned and developed matching with growth of generation and load and care shall be taken that there is no wasteful investment.

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

2.1.5 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. For this purpose, any generator who intents to connect with ISTS shall be allowed to be connected with Inter-State Transmission System.

2.1.6 In case of highly constrained areas like congested urban / semi-urban area, very difficult terrain (including hilly) 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 voltage level 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.

2.1.7 Routing of the transmission line may be planned in accordance with Central Electricity Authority (Technical Standards for Construction of Electrical Plants and Electric Lines) Regulations, 2010 and its amendment thereof, to minimise Right of Way (Row), technical options and line configurations.

2.1.8 PM Gati Shakti National Master Plan (PMGS-NMP) was launched on 13th October 2021 for providing multimodal connectivity infrastructure to various economic zones. It provides a digital platform for integrated planning and coordinated implementation of infrastructure connectivity projects. The information available on this platform may be used while planning of transmission system.

2.1.9 For planning of any new transmission lines or substations, the portal of PMGS-NMP can be used to identify preliminary feasibility of the same. In line with Section 39 of the Electricity Act, the STU shall act as the nodal agency for In-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.

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

2.1.11 The system parameters and loading of system elements shall remain within prescribed limits. The adequacy of the transmission system should be tested for different probable load-generation scenarios as detailed in chapter-3 of this manual.

2.1.12 The system shall be planned to operate within permissible limits both under normal as well as after probable credible contingency(ies) as detailed in subsequent chapters 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 defence mechanism, such as - load shedding, generation rescheduling, islanding, system protection schemes, etc. may be worked out to mitigate their adverse impact.

2.1.13 For strengthening of the transmission network, cost, reliability, right-of way requirements, transmission losses, down time (in case of up-gradation and re-conductoring options) etc. need to be studied. If need arises, addition of new transmission lines/ substations to avoid overloading of existing system including adoption of next higher voltage may be explored.

2.1.14 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.

2.1.15 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.

2.1.16 Communication system for new transmission system may be planned and implemented in accordance with Central Electricity Authority (Technical Standards for Communication System in Power System Operations) Regulations, 2020 and CEA Manual of Communication Planning in Power System Operation 2022 such that the communication system is available at the time of commissioning of the transmission system.

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 essential, 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 attached at Annexure-IV, however, additional data may be required at the time of planning studies.

3.1.2 Consideration of voltage level for ISTS planning the transmission network may be generally modelled down to 220kV level with exception for North Eastern Region, Uttarakhand, Himachal Pradesh and Sikkim, which may be modelled down to 132kV level.

3.1.3 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 modelled as a single unit, however the total lumped installed capacity of a single unit may be limited to 200 MW.

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

3.2 Time Horizons for transmission planning

3.2.1 Concept to commissioning for 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.

3.2.2 Base case models shall be prepared corresponding to load generation scenarios for a 5 year time horizon. These models 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 RE generation, high hydro generation, high demand, low demand and combination 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.

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 (for Light Load scenario, power drawl by energy storage elements such as pumped storage plants, BESS etc. shall also be considered)

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 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.

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 amendment 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 Annexure - III.

Note:

i) *As per the Indian Electricity Grid Code (IEGC), 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 backdown/ ramp-up its conventional (thermal/hydro) generation plants or revise their drawl 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.*

ii) *Further, to address the variability of the wind/solar projects, other aspects like reactive compensation, forecasting and establishment of renewable energy control centres may also be planned by STUs.*

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

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.

3.7 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 40% of the rated installed capacity. If the thermal units are encouraged to run with oil support, they may be modelled to run up to 25% of the rated 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 (including Nuclear)	$Q_{max} = 0.60 \times P_{max}$	$Q_{min} = (-)0.30 \times P_{max}$

Hydro units	Q_{max} = 0.48 x P_{max}	Q_{min} = (-)0.24 x P_{max}
Wind / Solar	Q_{max} = 0.33 x P_{max}	Q_{min} = (-)0.33 x 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.

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 may 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	745
400	412	388
230	240	212
220	240	203
132	142	125
110	119	102
66	70	62

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 (including Nuclear)	$Q_{max} = 0.50 \times P_{max}$	$Q_{min} = (-)0.10 \times P_{max}$
Hydro units	$Q_{max} = 0.40 \times P_{max}$	$Q_{min} = (-)0.20 \times P_{max}$
Wind / Solar	$Q_{max} = 0.20 \times P_{max}$	$Q_{min} = (-)0.20 \times P_{max}$

3.10.7 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.

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) EMTP studies

ii) Inertia

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 ∠δ) 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 para 3.12.3 above should be within the planning margins specified at para 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 the correct current is provided during and immediately following fault conditions. In case of non-availability of data, for wind and solar generation 0.8 and 1 respectively may be assumed in sub-transient reactance (X''_d) 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 (11kV, 13.8kV, 21kV 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 compared with for 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 highly 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 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 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. A system enters a state of voltage instability when as disturbance, increase in load demand or change in system condition 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.

3.14.7 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 word, 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.

3.14.8 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.

3.14.9 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

3.14.10 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.

3.14.11 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.

3.15 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

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.

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 – In-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.

3.16 EMTP studies

3.16.1 Electro Magnetic Transient Program (EMTP) is used for simulating electromagnetic, electromechanical and control system transient on multiphase electric power system.

3.16.2 EMTP 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. The typical studies viz. Temporary Over Voltage, Switching Over Voltage, Ferro resonance, Sub-Synchronous Resonance, Insulation Coordination etc. can be performed by using this programs.

3.16.3 During EMTP studies transmission elements viz. transmission line, transformer/reactor, Generator, Circuit Breaker, Lightening 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 the study analysis.

3.16.4 Temporary Over Voltage (TOV): TOV are weakly / undamped oscillatory phase-to-phase, phase-to-ground or longitudinal voltage stresses of relatively long duration (i.e., seconds, even minutes). They are often preceded by a transient overvoltage resulting from a switching operation, in a no / lightly loaded system. EMTP studies provides to characterize TOV, determine resulting problems, and evaluate mitigation alternatives.

3.16.5 Switching Over Voltage: When a line 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 on the equipment selection, protection and tower air 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 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.

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, the 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.

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 shall decline. However, Battery Energy Storage Systems (BESS), Synchronous Condenser etc. can provide fast response to arrest the frequency decline and help restore the frequency in same manner.

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.

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 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.

4.1.3 However, after suffering one contingency, grid is still vulnerable to experience second 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 applied 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-V.

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 accessed 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 (kVrms)				
	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.)

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 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 (with or without fixed series capacitor),
- Outage of an Inter-Connecting Transformer (ICT) / power transformer,
- 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.

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 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).

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

4.4.3.1 Under the scenario where a contingency as defined at Paragraph: 4.4.2 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.

4.4.3.2 In the 'N-1-1' contingency condition 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' (of 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/In-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 in a substation may be terminated in bays of same diameter, 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. This will avoid crossing of lines with multi-circuit towers.

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. 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	40 kA / 50 kA / 63 kA
400 kV	50 kA / 63 kA / 80 kA
220 kV	40 kA / 50 kA / 63 kA
132 kV	25 kA / 31.5 kA / 40 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.

5.1.6 Rating of the various substation equipments 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 station 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 Effort should be to explore possibility of planning a new substation instead of adding transformer capacity at an existing substation. 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

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.

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 (Construction of Electrical Plants & Electric Lines) Regulations, 2009 shall be implemented.

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

5.3.3 Sectionalisation and bus scheme should be as per Central Electricity Authority (Construction of Electrical Plants & Electric Lines) Regulations, 2009. Bus section shall be planned such a way that feeders are adequately distributed with respect to power flow with bus sectionalizers open condition. Further, sectionaliser arrangement may be implemented also keeping in view transformation capacity in each section, fault current rating adopted, number of feeders etc.

5.4 Reactive Power compensation

5.4.1 General:

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

5.4.1.2 Near to large RE complex(es) synchronous condenser(s) may be planned for dynamic voltage support, in addition to FACTS devices.

5.4.1.3 While planning of bus capacitors/reactors, aspects such as voltage sensitivity due to switching of these devices, size, reliability (contingency) etc. shall be considered.

5.4.1.4 Space provision for converting fixed line reactors/switchable line reactors to be usable as bus reactors after line opening with bypass arrangement for NGR/control switching.

5.4.1.5 RE generators to have provision to operate the generators in both voltage control mode and power factor control mode as per the grid requirements.

5.4.1.6 While planning Bus Reactor (BR), size, reliability aspect (outage of BR), etc. may be taken care of.

5.4.2 **Shunt capacitors**

5.4.2.1 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.

5.4.2.2 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.

5.4.2.3 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. It shall be responsibility of respective STU to plan suitable reactive compensation in their network including at 220kV and 132kV levels connected to ISTS, in order to fulfil this provision.

5.4.3 Shunt reactors

5.4.3.1 Switchable bus reactors shall be provided at EHV substations for controlling voltages within the limits (defined in the Paragraph: 4.3) 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)**
132kV (3-ph unit)	12.5 and 25
220kV (3-ph unit)	50, 25 (rated at 245kV)
400kV (3-ph unit)	50, 63, 80,125 and 250 (rated at 420kV)
765kV (1-ph unit)	80 and 110 (rated at 765kV)

5.4.3.2 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: 4.3(b) under all probable operating conditions.

5.4.3.3 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: 4.3(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.

5.4.3.4 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: 4.3(b).

5.4.4 Shunt FACTS devices

5.4.4.1 Shunt FACTS devices such as Static VAr Compensation (SVC) and STATCOM shall be provided where found necessary to damp the power swings and provide the system stability under conditions defined in the 'Reliability Criteria'. The dynamic range of static compensators shall not be utilized under steady state operating condition as far as possible.

5.4.5 Synchronous Condenser

5.4.5.1 A synchronous condenser (SC) is a synchronous machine operating without a prime mover. Reactive power output regulation of SC is performed by regulating the excitation current. The level of excitation determines if the synchronous condenser generates or consumes reactive power. SC provides improved voltage regulation and stability by continuously generating/absorbing adjustable reactive power, improved short-circuit strength and frequency stability by providing synchronous inertia.

5.4.5.2 The conventional power stations could be refurbished to a synchronous condenser, thereby potentially reducing initial capital cost. A synchronous condenser consumes a small amount of active power from the system to cover losses. As many gas and coal-based synchronous generators approach the end of their life, the retiring of a plant can possibly create a reactive power deficit at the local network, which may impact voltage reliability. The conversion of the existing generator to a synchronous condenser can be potentially economical and effective.

5.4.5.3 Operating Hydro generators in synchronous condenser mode may be a possible way for voltage control with the existing resources, which may be explored to regulate voltage in grid locally and thus preventing the switching of other elements for voltage control purpose, which in turn help in keeping the system reliability intact.

5.4.5.4 Synchronous Condenser may be planned considering techno-economic feasibility.

Chapter 6 ADDITIONAL CRITERIA

6.1 Wind / Solar / Hybrid projects

6.1.1 All the generation projects based on renewable energy sources shall be required to comply with Central Electricity Authority (Technical Standards for Connectivity to the Grid) Regulations, 2007 and its amendment thereof, for which requisite system studies shall be carried out by renewable generation project developer.

6.1.2 The GNA quantum to be considered while planning the evacuation system, both for immediate connectivity with the ISTS/In-STS and for onward transmission requirement.

6.2 Nuclear power stations

6.2.1 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 angular separation between start-up power source and the generation switchyard should be, as far as possible, be maintained within 10 degrees.

6.2.2 The evacuation system shall generally be planned so as to terminate it at large load centres to facilitate islanding of the power station in case of contingency.

6.3 HVDC Transmission System

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

6.3.2 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 in chapter-3 and contingencies given at Paragraph: 4.4. Further, in areas where multiple Conventional HVDC bipoles are feeding power (multi infeed), the appropriate studies may be carried at planning stage so as to avoid commutation failure.

6.4 Zone-3 settings

6.4.1 The transmission utilities should ensure that zone-3 relay settings of the transmission lines is such that they do not trip at extreme loading of line. For this purpose, the extreme loading may be taken as 120% of thermal current loading limit and assuming 0.9 per unit voltage (i.e. 360kV 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 limited to as calculated from relay impedance assuming 0.95 pu voltage, provided it is permitted by stability and voltage limit considerations as assessed through appropriate system studies.

6.5 Resiliency

6.5.1 The IEEE Technical Report PES-TR65 defines resilience as “The ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event”. This may also be simply defined as “The ability to protect against and recover from any event that would significantly impact the grid”.

6.5.2 **Resilience v/s Reliability:**

The IEEE defines Reliability as “The probability that a system will perform its intended functions without failure, within design parameters, under specific operating conditions, and for a specific period of time.” Further different utilities worldwide have defined and developed different reliability standards for robustness, resourcefulness, rapid recovery and adaptability of their power systems.

The IEEE Technical Report PES-TR83 states that reliability is a system performance measure, and resilience is a system characteristic. Generally better reliability results in better resilience and vice versa. However, in some cases, a highly reliable system may have lower resilience and vice versa. The primary difference between reliability and resilience is that resilience encompasses all events, including “High Impact – Low Frequency” events commonly excluded from the reliability calculations.

6.5.3 Resilience Evaluation: Several frameworks and methods for advancing resilience evaluation have been developed in the last decade. These frameworks can be grouped into two general categories: qualitative and quantitative frameworks.

i) Qualitative Frameworks: Qualitative frameworks usually evaluate the power system's resilience, along with other interdependent systems, such as information systems, fuel supply chain, and other such infrastructures. These frameworks evaluate resilience capabilities such as preparedness, mitigation, response, and recovery. Qualitative frameworks are appropriate for long-term planning because they provide a comprehensive and holistic depiction of system resilience.

ii) Quantitative Frameworks: Quantitative frameworks are based on the quantification of system performance. Resilience is quantitatively evaluated based on the reduced magnitude and duration of deviations from the targeted or acceptable performance. Quantitative resilience metrics should be: 1) performance-related, 2) event-specific, 3) capable of considering uncertainty, and 4) useful for decision-making.

An effective resiliency framework should strive to minimize the likelihood and impacts of a disruptive event from occurring and provides the right guidance and resources to respond and recover effectively and efficiently when an incident happens. This can be accomplished by applying the framework toward assessing and developing a mitigation program with the five main focus areas: Prevention, Protection, Mitigation, Response, and Recovery.

6.5.4 The Recommended Measures in the "Report of Task Force on Cyclone Resilient Robust Electricity Transmission and Distribution Infrastructure in the Coastal Areas" accepted by Ministry of Power vide letter dated 10th June, 2021 for Creating Resilient Transmission Infrastructure may be referred.

6.6 Economic Analysis

6.6.1 In order to identify the most suited techno-economical transmission system, it is essential to carry out economic analysis of planned alternatives. Therefore, to carry out cost-benefit/economic analysis for each of the planned alternatives, following estimated figures may be computed.

a) project cost,
b) annual transmission charges and
c) impact on the existing total annual transmission charges.

6.7 Right of Way (RoW)

6.7.1 For laying electricity transmission lines, licensee erects towers at stipulated intervals and conductors are strung on these towers maintaining a safe height depending on the voltage and other geographical parameters. Thus, typical transmission lines have following two kinds of impact: (i) Tower base area which is more or less completely lost or loses its productivity due to severe restriction an access; (ii) Corridor of land underneath strung conductor between two towers may be adversely affected by imposition of restriction on its usage. The maximum width of RoW corridor is calculated on the basis of tower design, span, and wind speed, maximum sag of conductor and its swing plus other requirement of electric safety.

6.7.2 In order to reduce RoW the technological options for reducing the tower footing/base, area/corridor requirements may be explored. For possibility of reduction of transmission corridor width/selective restricted use of corridor in urban zones by using technical advances/ raising heights of towers/ adequate safety measures/revisiting clearance requirements.

6.7.3 Central Electricity Authority (Technical Standards for Construction of Electric Plants and Electric Lines) Regulations, provides that, Right of way for transmission lines shall be optimized keeping in view the corridor requirement for the future by adopting suitable alternative of multi-circuit or multi-voltage lines as applicable. Following may be adopted to optimise RoW utilisation:

- 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, space constrained terrains, polluted areas etc)

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.

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
GNA	:	General Network Access
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
RE	:	Renewable Energy
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

(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 (in %) may be calculated using following factors:

Seasons	**Region**	**Wind Projects**	**Solar Projects**
Summer	Eastern	60	80
	Northern	60	80
	North Eastern	60	80
	Southern	70	80
	Western	70	80
Winter	Eastern	60	60
	Northern	60	60
	North Eastern	60	60
	Southern	70	60
	Western	60	60
Monsoon	Eastern	80	70
	Northern	80	70
	North Eastern	80	70
	Southern	80	70
	Western	80	70

Note: The above factors may be revised from time to time.

Annexure- IV

Data Base Format for Transmission Planning

1. STU can provide input in a PSS/E File format or as per the format enclosed.
2. Unless specified all elements specified in the list shall be treated as of STU
3. Data required includes Substations (Bus), Lines and Transformers connected the Station (Bus), Generations, Loads and shunt MVAR list.
4. Once the existing data is finalized year wise data may be provided in the format given here with for time frame till 2025.
5. Data Format:
   a. Substation (**List-1**): Consists of buses represented in the file along with name and voltage level, availability of Load and injection by generator
   b. Transmission lines (**List-2**): Consists of lines along with names of the substations interconnected by them, with line length, and line reactors if any
   c. Generator connected (**List-3**): Various generating of the state modelled in the file along with parameters are given in the list with values like P_{max}, P_{min}, Q_g, Q_{max}, Qq_{min}, MBASE, Zr. ZX, Xr and XT
   d. Loads (**List-4**): Loads considered both P and Q
   e. Shunt (**List-5**): For FIXED bus shunt includes shunt capacitor or bus reactors. Reactors may be shown negative
   f. Transformer (**List-6**): Substation Name, from and to bus Volt, Tap Position, Number of transformers, Transformer MVA, % Impedance.
   g. 2-terminal HVDC (LCC) (**List-7**): Rectifier & Inverter Substation Name, Control Mode, Schedule Voltage, Max. & Min. firing angle, Primary Base Voltage, Bridges in series, DC Resistance, Rated Power
   h. 2-terminal HVDC (VSC) (**List-8**): Converter-1&2 Substation Names, Control Mode, losses, Schedule Voltage, AC current, Max & Min Reactive Capability, Rated Power
   i. FACTS & STATCOM (**List-9**): Substation Name, Control Mode, P & Q setpoint,, Size

j. Switched Shunt (**List-10**): Substation Name, Control Mode, Remote Bus, Step Size

Similarly, for every year additional element and load – generation may be given in the above format.

Further, please refer guidelines for data to be provided in the PSSE format

<table>
<tr><th colspan="7">Guidelines</th></tr>
<tr><td>1</td><td colspan="6">CTU would circulate the last updated load flow file for planning horizon amongst all stakeholders as per requirement. STUs to indicate changes in network topology, load, generation, etc. in PSSE format (python or idev files) supported by data indicating the above changes in given formats.</td></tr>
<tr><td>2</td><td colspan="6">A common bus number nomenclature is to be followed by all the stakeholders for creation of new bus numbers in PSSE after examining the next available unique bus nos. in the given series.</td></tr>
<tr><td></td><td></td><td></td><td></td><td colspan="3"></td></tr>
<tr><td></td><td>Region</td><td>State</td><td>Voltage</td><td colspan="3">Unique Bus Number</td></tr>
<tr><td></td><td>D1</td><td>D2</td><td>D3</td><td>D4</td><td>D5</td><td>D6</td></tr>
<tr><td></td><td colspan="6">Example: In bus number 542001, 5 represents southern region, 4 represents Tamil Nadu, 2 represents 230 kV and 001 is the bus number</td></tr>
<tr><td>3</td><td colspan="6">Detailed nomenclature for bus numbering, zone and area allocation is attached as Annexure-II.</td></tr>
<tr><td>4</td><td colspan="6">Regarding owner assignments for identification of type of generators based on source of fuel & sector nomenclature Annexure-III may be referred.</td></tr>
</table>

Note: *Please note that only incremental changes in load flow file circulated by CTU are to be indicated in these formats after recording the changes through idev/python file in PSSE format*

List-1

<u>Bus Data</u>

Data as on Month of the Year						
Sl. No. (Define Bus no)	**Name of the S/s or bus (as to be reflected in PSSE file) - Max. 12 characters**	**Voltage Level (765/400/230/220/132/110/66/33kV)**	**Load Bus (Yes/No)**	**Generator bus (Yes/No)**	**Remarks (Existing/ Under construction/ Planned)**	**Year of Commissioning**
XXX	AAAAA8	765/400				
XXX	BBBBBB4	400/220				
XXX						

List-2

Line Data

Note: *1) Unit id or circuit id or representative. If circuit id or unit id is 2, it represents 2 unit or line or transformer etc.*

2) Unless otherwise specified – Based on conductor configuration and Line voltage standard parameters will be assumed as per the planning criteria of CEA.

Data as on Month of the Year																				
From BUS (Name)(refer sheet "BUS No" for name as to be used in PSSE)	To BUS (Name) (refer sheet "BUS No" for name as in PSSE)	CKT id	Length (km)	Line voltage (kV)	Line Type (S/c or D/c or Multi Ckt)	Conductor type (e.g. AL59/ ACSR MOOSE / HTLS/Zebra etc.)	Conductor Configuraton (Single/Twin /Tripple/ Quad/ Hexa)	Design Ambient / Conductor Temperature	Either in actuals or in pu on 100MVA base			in MVA	in MVA		in pu on 100MVA base		in pu on 100MVA base		Remarks (Existing / under construction/ planned)	Year of Commissioning
									R in pu	X in pu	B in pu	Rate A (SIL Loading)	Rate B	Rate C	GI	BI line reactor at from bus end in pu (Fixed / Switchable)	GJ	BI line reaactoroat To bus end in pu(Fixed / Switchable)		
AAA	BBB	1	291	765	D/c	Zebra	Hexa	45/75	XX	XX	XX	2200	3000		XXXXXX	-2.4 (Fixed)	XXXXXX	-2.4 (Switchable)		
AAA	BBB	2	291	765	D/c	Zebra	Hexa		XX	XX	XX	2200	3000			-2.4 (Fixed)		-2.4 (Switchable)		
BBB	CCC	1	208	765	S/c	**Bersimis**	Quad		XX	XX	XX	2200	3000			0		-2.4 (Switchable)		
DDD	CCC	2	208	765	S/c	Bersimis	Quad		XX	XX	XX	2200	3000			0		-2.4 (Switchable)		
DDD	KKK	1	75	220	D/c	ZEBRA	Single		XX	XX	XX	130								
CCC	EEE	2	75	220	D/c	ZEBRA	Single		XX	XX	XX	130								
CCC	FFF	1	77	132	D/c	PANTHER	Single		XX	XX	XX	65								
GGG	SSS	2	77	132	D/c	PANTHR	Single		XX	XX	XX	65								
GGG	CCC	1	44	220	D/c	ZEBRA	Single		XX	XX	XX	130								

List-3

Generator Data

Note:

1) *Unit id or circuit id or representative. If circuit id or unit id is 2, it represents 2 unit or line or transformer etc.*
2) *In case of RE generators, aggregated generation (lumped) at STU/Developer PS may be defined.*
3) *The load shall be adjusted as per season and despatch considered. If already adjusted it may be mentioned*.

Fuel Type	Coal	Hydro	Gas	Nuclear	Wind	Solar
ID No format	T, T1 to T9	H, H1 to H9	G, G1 to G9	N, N1 to N9	WF (Wind farms), W1 to W9	SP (Solar Parks), S1 to S9

State	**SOLAR ROOF TOP CAPACITY IN MW**			
	By 2022	**By 2023**	**By 2024**	**By 2025….**

RE	**RPO Commitment (%)**			
	By 2022	**By 2023**	**By 2024**	**By 2025…**
Solar				
Non Solar				

Data as on Month of the Year

Bus Name	Voltage Level (kV)	GT voltage rating	GT MVA Rating or PF	Fuel Type	Unit Id	Unit size	Owner (State/ Private)	P_{max} Gen capacity (MW)	P_{min} Technical Min (MW)	Q_{Max} (Mvar)	Q_{Min} (Mvar)	Mbase (MVA)	R Source (pu)	X Source (pu)	R_{Tran} (pu on machine MVA base) of GT	X_{Tran} (pu on machine MVA base) of GT	In Case of RE generation control mode	Power factor	Year of Commissioning
b	13	13/220kV	248	Coal	T11	210	State						0	0.2	0	14.50%			
b	13	13/220kV	248	Coal	T2	210	Private						0	0.2	0	14.50%			
a	11	13/220kV	175	Hydro	H1	155							0	0.32	0	14.50%			
a	11	13/220kV	175	Hydro	H2	155							0	0.32	0	14.50%			
c	15	13/220kV	150	Gas	G1	130							0	0.18	0	14.50%			
d	23	15.5/220	249	Nuclear	N1	220							0	0.23		14.50%			
e	22			Wind	W1	50										14.50%			
f				Solar	S1	200										14.50%			

List-4

Load Data

Note:

1) *Quarter wise load can be indicated bus wise or as a percentage of maximum Annex table*
2) *The load shall be adjusted as per season and despatch considered. If already adjusted it may be mentioned.*

Data as on Month of the Year (for 20XX year)					2023-24….		
Bus Name (132kV/110/66/33kV) (Max. 12 character)	**Voltage level (220kV / 132kV/ 110kV) Load is connected to**	**Active Load (MW) (P_{max})**	**Reactive Load (QL) or Power factor for Peak load case**	**Reactive Load (QL) or Power factor for off-peak load case**	**Active Load (MW) (P_{max})**	**Reactive Load (QL) or Power factor for Peak load case**	**Reactive Load (QL) or Power factor for off-peak load case**
ABC	220	120			130		
DEF	132	85			95		
XYZ	220	150			160		
ABC	220	220			240		

	Roof top solar adjusted YES/NO	2022-23		2023-24		2024-25…	
		Peak	**Off-Peak**				
Maximum Load							
Quarter-1		80%	50%				
Quarter-2		75%	55%				
Quarter-3		80%	50%				
Quarter-4		80%	50%				

List-5

Fixed Shunt Data

Note:

1) *Unit id or circuit id or representative. If circuit id or unit id is 2, it represents 2 unit or line or transformer etc.*

Data as on Month of the Year					
S.No.	**Bus Name 765kV/400kV/230kV/132kV)**	**Voltage level (132kV/ 110kV)**	**Id**	**BL**	**Year of Commissioning**
	AAAA8	765	1	-240	
	AAAA8	765	2	-240	
	BBBB8	765	1	-240	
	BBBB8	765	2	-240	
	CCCC1	132	1	100	
	DDDD2	220	1	150	
	GGGG1	132	2	70	
	FFFFF2	220	1	253	
	HHHH4	400	1	-80	
	HHH4	400	1	-80	

List-6

Transformer/ ICT Data

Note:

1) *Unit id or ckt id or representative. If ckt id or unit id is 2, it represents 2 unit or line or transformer etc.*

Data as on Month of the Year										
From BUS (refer sheet "BUS No" for name as to be used in PSSE)	**To BUS (refer sheet "BUS No" for name as to be used in PSSE)**	**CKT**	**Voltage level (kV) (to bus no)**	**No of taps**	**Voltage change /step**	**Tap Positions**	**MVA Rating (Rate A)**	**Winding MVA Base**	**% Impedance on transformer base**	**Year of Commissioning**
AAAA8	AAAA4	1	765/400	17	1.25%	8	1500	1500	12.50%	
BBBBB8	BBBBB4	1	765/400	17	1.25%	8	1500	1500	12.50%	
CCCCC8	CCCCC4	1	765/400	17	1.25%	8	1500	1500	12.50%	
DDDD8	DDDD4	1	765/400	17	1.25%	8	1500	1500	12.50%	
EEEE8	EEEE4	1	765/400	17	1.25%	8	1500	1500	12.50%	
FFFFF4	FFFFF2	1	400/220	17	1.25%	8	500	1500	12.50%	
GGGG4	GGGG2	1	400/220	17	1.25%	8	300	1500	12.50%	
BBBBB11	BBBB2	1	220/132	17	1.25%	8	100	1500	12.50%	

List-7

2-TERMINAL HVDC (LCC)

Data as on Month of the Year																
Line						**Converter**										
Rectifier Bus (refer sheet "BUS No" for name as to be used in PSSE)	**Inverter Bus (refer sheet "BUS No" for name as to be used in PSSE)**	**Control Mode (Blocked, Power, Current)**	**Set Val (Amp or MW)**	**Rdc (Ohm)**	**Schedule Voltage (kV)**	**Max. Firing angle (deg)**	**Min. Firing angle (deg)**	**Bridges in series (nos.)**	**Primary Base (kV)**	**Commutating Resistance**	**Commutating Reactance**	**Tap setting (pu)**	**Max. Tap setting**	**Min. Tap setting**	**Year of Commissioning**
AAAA8	AAAA4	Power	1000	10.7	500	17.5	12.5	2	400	0.3	7.8	1.03	1.2	0.85	
BBBBB8	BBBBB4														

List-8

<u>2-TERMINAL HVDC (VSC)</u>

Data as on Month of the Year													
Converter Bus -1 (refer sheet "BUS No" for name as to be used in PSSE)	**Converter Bus -2 (refer sheet "BUS No" for name as to be used in PSSE)**	**Control Mode (Blocked/ Power/ Voltage)**	**Set Val (kV or MW)**	**Rdc (Ohm)**	**A loss (kW)**	**B loss (kW/ Amp)**	**Schedule Voltage (kV)**	**AC Current rating (amp)**	**Max. Reactive Power (MVAr)**	**Min. Reactive Power (MVAr)**	**RMPCT (%)**	**Year of Commissioning**
AAAA8	AAAA4	Power	1000	10.7	5000	2.5	500	3300	2000	-2000	50	
BBBBB8	BBBBB4											

List-9

STATCOM

Data as on Month of the Year													
Bus Number (refer sheet "BUS No" for name as to be used in PSSE)	**Control Mode (Blocked, Normal)**	**P set point (MW)**	**Q Setpoint (MVAr)**	**V send Setpoint**	**Shunt Max (MVA)**	**RMPCT (%)**	**Bridge Max (MW)**	**V Term Max (pu)**	**V Term Min (pu)**	**V series Max (pu)**	**I series Max (pu)**	**Dummy series X(pu)**	**Year of Commissioning**
AAAA8	Power												
BBBBB8													

List-10

Switched Shunt

Data as on Month of the Year														
Bus Number (refer sheet "BUS No" for name as to be used in PSSE)	**Control Mode (Locked, Continuous Cntrl Voltage, Cntrl Plant MVAr)**	**Vhi (pu)**	**Vlo (pu)**	**Remote Bus**	**RMPCT (%)**	**B init (MVAr)**	**Blk 1 Steps**	**Blk 1 B step (Mvar)**	**Blk 2 Steps**	**Blk 2 B step (Mvar)**	**Blk 3 Steps**	**Blk 3 B step (Mvar)**	**Year of Commissioning**
AAAA8	Power												
BBBBB8													

Annexure- V

DATA FOR TRANSMISSION PLANNING STUDIES

Table- I(a)

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

Actual system data based on actual tower dimensions, 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
	Quad	#ACSR Bersimis	S/C						
	Hexa	@ACSR Zebra	D/C	2.096E-6	4.360E-5	2.66E-2	3.839E-5	1.576E-4	1.613E-2
	Hexa	#ACSR Zebra	D/C	2.076E-6	4.338E-5	2.675E-2	3.662E-5	1.582E-4	1.605E-2
	Hexa	#AL59 (61/3.08)	D/C	2.056E-6	4.351E-5	2.671E-2	3.660E-5	1.583E-4	1.609E-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
	Twin	ACSR Moose	D/C	1.800E-5	1.923E-4	6.02E-3	1.672E-4	6.711E-4	3.669E-3
	Twin	AL59 (61/3.31)	D/C	1.871E-5	1.946E-4	5.980E-3	1.556E-4	6.777E-4	3.650E-3
	Twin	ACSR Lapwing	S/C	1.230E-5	1.910E-4	6.08E-3	6.685E-5	7.134E-4	3.926E-3
	Twin	ACSR Lapwing	D/C	1.204E-5	1.905E-4	6.08E-3	1.606E-4	6.651E-4	3.682E-3
	Twin	Moose eq. AAAC	S/C	1.934E-5	2.065E-4	5.67E-3	1.051E-4	7.730E-4	3.660E-3
	Triple	ACSR Zebra	S/C	1.401E-5	1.870E-4	5.86E-3	7.616E-3	6.949E-4	3.783E-3
	Triple	ACSR Snowbird	D/C	1.193E-5	1.721E-4	6.733E-3	1.477E-3	6.499E-4	3.950E-3
	Quad	ACSR Zebra	S/C	1.050E-5	1.590E-4	6.60E-3	5.708E-3	5.940E-4	4.294E-3
	Quad	ACSR Bersimis	S/C	7.416E-6	1.560E-4	7.46E-3	4.031E-3	5.828E-4	4.854E-3
	Quad	ACSR Moose	S/C	9.167E-6	1.580E-4	7.32E-3	1.550E-4	6.250E-4	4.220E-3
	Quad	ACSR Moose	D/C	9.177E-6	1.582E-4	7.33E-3	1.557E-4	6.246E-4	4.237E-3
	Quad	AL59 (61/3.31)	D/C	9.506E-6	1.594E-4	7.299E-3	1.439E-4	6.318E-4	4.221E-3
	Quad	Moose eq. AAAC	S/C	9.790E-6	1.676E-4	6.99E-3	5.320E-3	6.260E-4	4.510E-3

Voltage (kV)	Config.	Type of conductor	Ckt	Positive sequence			Zero sequence		
				R	X	B	R_0	X_0	B_0
	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
	Single	ACSR Drake	S/C	1.800E-4	8.220E-4	1.41E-3	6.1E-4	2.56E-3	8.050E-4
	Single	ACSR Moose	S/C	1.547E-4	8.249E-4	1.42E-3	4.545E-4	2.767E-3	8.906E-4
	Single	ACSR Kunda	S/C	1.547E-4	8.249E-4	1.42E-3	4.545E-4	2.767E-3	8.906E-4
	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			

@: With 15m ground clearance

#: With 18m ground clearance

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	Stranding/wire diameter (mm)		Overall diameter (mm)	DC Resistance (Ω/km)	AC Resistance values at different temperatures (in Ω/km)		
	Al/Al alloy wire	steel wire		20º C	75 º C	85 º C	95 º C
ACSR	54/3.18	7/3.18	28.62	0.06868	0.08686	0.08968	NA
AAAC	61/3.19	NA	28.71	0.06819	0.08269	0.08511	0.08754
AL59	61/3.08	NA	27.72	0.06530	0.07998	0.08243	0.08488

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	Stranding/wire diameter (mm)		Overall diameter (mm)	DC Resistance (Ω/km)	AC Resistance values at different temperatures (in Ω/km)		
	Al/Al alloy wire	steel wire		20º C	75 º C	85 º C	95 º C
ACSR	42/4.57	7/2.54	35.04	0.04242	0.05451	0.05622	NA
AAAC	61/4.0	NA	36.00	0.04337	0.05350	0.05502	0.05654
AL59	61/4.02	NA	36.18	0.03840	0.04814	0.04955	0.05097

Table- I(d)

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	Stranding/wire diameter (mm)		Overall diameter(mm)	DC Resistance (Ω/km)	AC Resistance values at different temperatures (Ω/km)		
	Al/Al alloy wire	steel wire		20° C	75 ° C	85 ° C	95 ° C
ACSR	54/3.53	7/3.53	31.77	0.05552	0.07046	0.07273	NA
AAAC	61/3.55	NA	31.95	0.05506	0.06719	0.06914	0.07109
AL59	61/3.52	NA	31.70	0.0501	0.06190	0.06377	0.06564
AL59	61/3.31	NA	29.79	0.0566	0.06961	0.07173	0.07385

Table- I(e)

The resistance data (in Ω/km) for **Panther 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	Stranding/wire diameter (mm)		Overall diameter(mm)	DC Resistance (Ω/km)	AC Resistance values at different temperatures (Ω/km)		
	Al/Al alloy wire	steel wire		20° C	75 ° C	85 ° C	95 ° C
ACSR	30/3.0	7/3.0	21.00	0.1390	0.17029	0.17586	NA
AAAC	37/3.15	NA	22.05	0.1151	0.13848	0.14261	0.14674
AL59	37/3.08	NA	21.56	0.1075	0.13060	0.13466	0.13873

Table- I(f)

Name of Conductor	Stranding/wire diameter (mm)		Overall diameter(mm)	DC Resistance (Ω/km)	AC Resistance values at different temperatures (Ω/km)		
	Al wire	steel wire		20° C	75 ° C	85 ° C	95 ° C
ACSR Snowbird	42/3.99	7/2.21	30.57	0.05516	0.07024	0.07248	NA

ACSR Lapwing	45/4.78	7/3.18	38.22	0.0358	0.04632	0.04775	NA

Note:

ACSR - Aluminum Conductor Steel Reinforced

AAAC - All Aluminum Alloy Conductor, corresponding to 53.0% of IACS (based on IEC standard)

AL 59 - High conductivity Aluminium Alloy Conductor as per IS-398, Part-6

Any conductor other than above shall be as per IS 398. In case Indian Standards is not available for the same, IEC/ IEEE or equivalent international Standards and codes shall be followed.

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/Bersimis/Moose/Panther/Snowbird/Lapwing are also given in following tables:

Thermal Loading Limits for ACSR Zebra equivalent Conductors:

Name of Conductor	Stranding/wire diameter (mm)		Ambient Temperature (ºC)	Ampacity for Maximum Conductor Temperature (ºC)			
	Al/Al alloy wire	steel wire		65 º C	75 º C	85 º C	95 º C
ACSR Zebra	54/3.18	7/3.18	40	451	626	756	NA
			45	328	546	694	NA
			48	222	492	654	NA
			50	103	453	625	NA
AAAC	61/3.19	NA	40	461	642	776	887
			45	335	560	713	834
			48	227	505	671	800
			50	104	464	642	776
AL59	61/3.08	NA	40	469	649	783	894
			45	343	567	719	840
			48	237	512	678	806
			50	123	471	648	782

Thermal Loading Limits for ACSR Bersimis equivalent Conductors:

Name of Conductor	Stranding/wire diameter (mm)		Ambient Temperature (ºC)	Ampacity for Maximum Conductor Temperature (ºC)			
	Al/Al alloy wire	steel wire		65 º C	75 º C	85 º C	95 º C
ACSR Bersimis	42/4.57	7/2.54	40	569	816	997	NA
			45	389	706	912	NA
			48	217	630	856	NA
			50	NA	574	817	NA
AAAC	61/4.0	NA	40	573	827	1013	1166
			45	387	714	926	1093
			48	206	637	870	1047
			50	NA	580	830	1015
AL59	61/4.02	NA	40	604	872	1069	1229
			45	408	754	977	1153
			48	215	672	917	1104
			50	NA	611	875	1070

Thermal Loading Limits for ACSR Moose equivalent Conductors:

Name of Conductor	Stranding/wire diameter (mm)		Ambient Temperature (ºC)	Ampacity for Maximum Conductor Temperature (ºC)			
	Al/Al alloy wire	steel wire		65 º C	75 º C	85 º C	95 º C
ACSR Moose	54/3.53	7/3.53	40	501	707	858	NA
			45	354	614	787	NA
			48	222	551	740	NA
			50	NA	504	707	NA
AAAC	61/3.55	NA	40	512	724	881	1010
			45	361	629	808	948
			48	225	565	760	909
			50	NA	517	726	882
AL59	61/3.52	NA	40	534	754	916	1049
			45	377	655	840	985
			48	237	588	790	944
			50	NA	538	755	916
AL59	61/3.31	NA	40	503	703	852	975
			45	362	613	782	916
			48	239	552	736	878

Name of Conductor	Stranding/wire diameter (mm)		Ambient Temperature (ºC)	Ampacity for Maximum Conductor Temperature (ºC)			
	Al/Al alloy wire	steel wire		65 º C	75 º C	85 º C	95 º C
			50	88	507	704	852

Thermal Loading Limits for ACSR Panther equivalent Conductors:

Name of Conductor	Stranding/wire diameter (mm)		Ambient Temperature (ºC)	Ampacity for Maximum Conductor Temperature (ºC)			
	Al/Al alloy wire	steel wire		65 º C	75 º C	85 º C	95 º C
ACSR Panther	30/3.0	7/3.0	40	317	424	505	NA
			45	244	374	465	NA
			48	187	341	440	NA
			50	136	317	422	NA
AAAC	37/3.15	NA	40	352	474	566	643
			45	269	418	522	605
			48	204	380	493	582
			50	144	353	473	565
AL59	37/3.08	NA	40	362	486	580	658
			45	278	429	535	619
			48	212	390	505	595
			50	152	362	485	578

Thermal Loading Limits for following ACSR Conductors

Name of Conductor	Stranding/wire diameter (mm)		Ambient Temperature (ºC)	Ampacity for Maximum Conductor Temperature (ºC)			
	Al wire	steel wire		65 º C	75 º C	85 º C	95 º C
ACSR Snowbird	42/3.99	7/2.21	40	502	703	853	NA
			45	358	613	782	NA
			48	232	550	736	NA
			50	63	505	703	NA
ACSR Lapwing	45/4.78	7/3.18	40	615	896	1101	NA
			45	405	772	1006	NA
			48	187	686	944	NA
			50	NA	622	899	NA

The above data has been calculated based on following assumptions:

- Elevation above sea level = 0 m
- Solar radiations = 1045 W/m2.
- Wind velocity considering angle between wind & axis of conductor as 90
  degrees = 0.56 m/sec
- Solar Absorption Coefficient = 0.8
- Emissivity Coefficient = 0.45
- Effective angle of incidence of sun's rays= 90 deg

Note: 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 after due calculation given in IS-9676.

High Temperature Low Sag conductors (HTLS)

HTLS conductors are capable of being operated continuously at temperatures as high as 250º C without any degradation in mechanical or electrical properties. However, in such conductors, the increase in sag is not linear at all temperatures because above a certain temperature called 'knee point temperature', the conductor experiences a sag increase due to the expansion of core alone (coefficient of linear expansion of core wires are comparatively lower than the complete conductor). This is because of the higher thermal expansion rate of aluminium which causes all the stress of the conductor to be borne by the core beyond the knee point temperature. Therefore, beyond the knee point temperature, the new expansion coefficient of the conductor will be the same as that of the core, resulting in relatively low sag increase when operated at high temperature.

Indicative parameters of HTLS conductor:

Transmission Line	Ampacity of HTLS per conductor	Minimum Conductor diameter (mm)	Maximum DC Resistance at 20°C (Ω/km)	Sub-conductor Spacing (mm)
400kV Transmission line with Twin HTLS conductor	------ A*	28.62	0.05552	450
220 kV transmission line with single HTLS conductor	-------A*	25	0.06868	NA

***Ampacity shall be decided based on actual MVA capacity of circuit.**

Some of the common types of HTLS conductors are as follows:

1. Aluminium Conductor Steel Supported Conductor
2. INVAR Conductor
3. GAP Conductor
4. Composite core Conductor

Note: Any new technology can be adopted which follows any National/International standard for design, safety and corresponding testing.

Table-III

(Sag of conductor on Transmission Lines)

Indicative sag values for various types of conductors are given below:

Transmission Line	Name of Conductor		Initial condition			Sag (in meter)
		Span(m)	Everyday conductor Temp. º C	Initial wind (%)	Everyday conductor tension (%of UTS)	85 º C
765 kV D/C	ACSR Zebra (Hexa)	400	32	0	22	13.26
400 kV D/C	ACSR Moose (Twin/Quad)	400	32	0	22	13.26
400 kV D/C	ACSR Snowbird (Triple)	400	32	0	22	14.74
220 kV D/C	ACSR Zebra	350	32	0	25	9.63
132 kV D/C	ACSR Panther	320	32	0	25	7.42

Note:

1. For selection of initial condition for Sag-Tension calculation, IS - 802(part1/Sec1) shall be followed.
2. The minimum ground clearance from the bottom conductor shall not be less than 18000mm for 765 KV, 8840 mm for 400KV, 7020 mm for 220KV and 6100 mm for 132KV lines at the maximum sag conditions i.e at max temperature as indicated in tower spotting data and still air.

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 % (for 400kV and below) 14% (for 765kV)

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 (Modelling 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
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

Typical Parameters	Hydro	Thermal	
		< 210 MW	**> 210 MW**
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

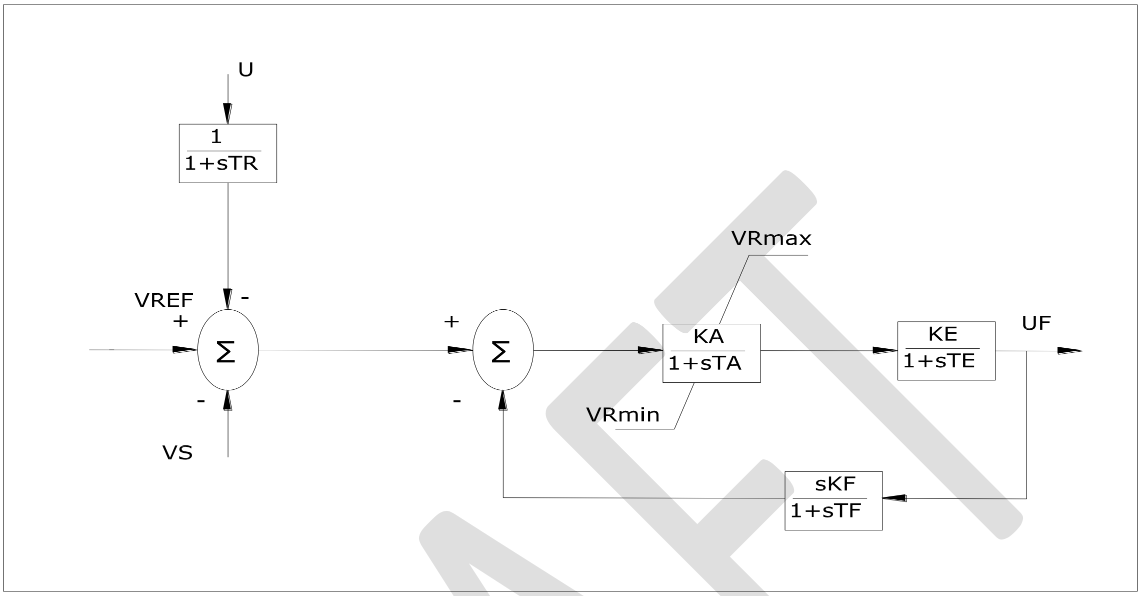
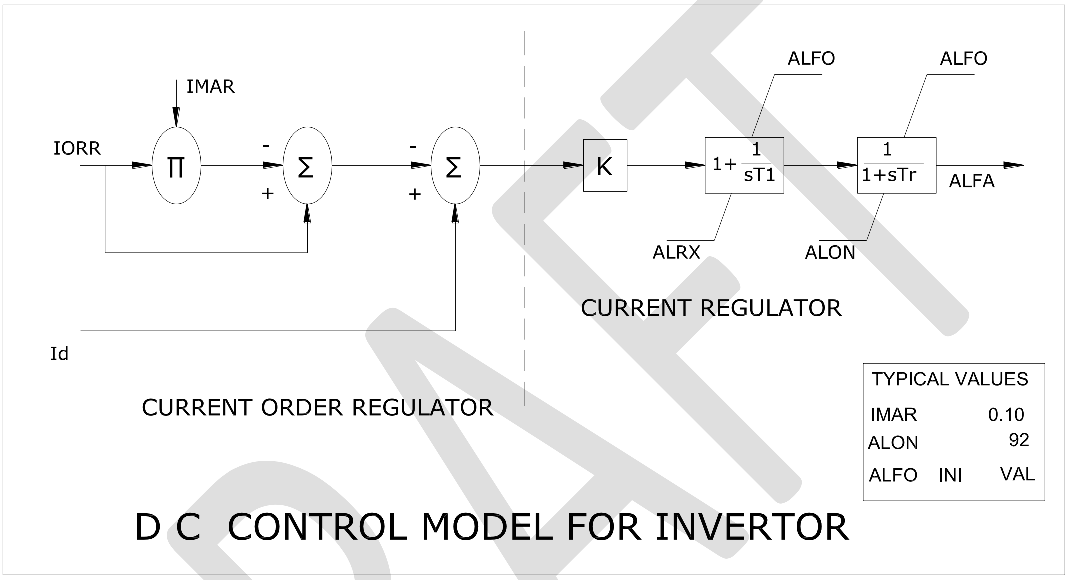
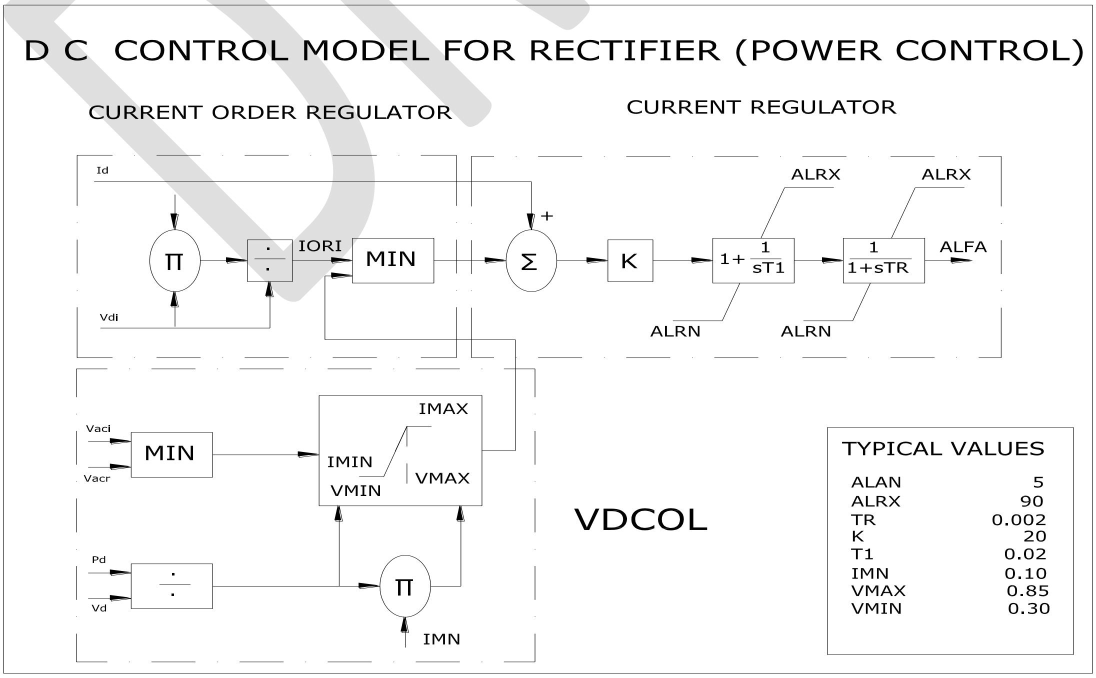


Table- VII
(Modeling for HVDC)

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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