HARYANA ELECTRICITY REGULATORY COMMISSION

Standards for Transmission Licensee

a)	Transmission System Planning and Security Standards
b)	Power Supply Security Planning Standards
c)	Transmission Operating Standards
d)	Power Supply Operating Standards

GENERAL

1. INTRODUCTION

Pursuant to the clause 19.4(a) of the Haryana Transmission and Bulk supply license the licensee shall plan and operate its Transmission System and shall plan procurement of electricity and make the same available to Distribution Licensees in conformity with the following standards.

S.N	Standards	Chapter
a)	Transmission System Planning and Security Standards	1
b)	Power Supply Security Planning Standards	2
c)	Transmission Operating Standards	3
d)	Power Supply Operating Standards	4

Not withstanding anything contained in these standards the Licensee shall not infringe or violate any of the provisions of the Indian Electricity Rules 1956.

2. DEFINITIONS

2.1 In these standards, unless the context otherwise requires

S.N		Definition
1	Act	Haryana Electricity reform Act 1997
2	Rules	Indian Electricity Rules, 1956
3	Grid Code	Code prepared by the Licensee in accordance with the terms of Condition -17 of the Transmission and Bulk Supply License, 1999. and approved by the Commission.
4	Grid Code Review Panel/Panel	a panel set up under Grid Code
5	Generator	an organisation that generates electricity and who is subject to the Grid Code
6	CBIP	Central Board of Irrigation and Power
7	CEA	Central Electricity Authority
8	HERC/Commission	Haryana Electricity Regulatory Commission
9	NREB	Northern Regional Electricity Board
10	NRLDC	Northern Regional Load Despatch Centre
11	PGCIL	Power Grid Corporation of India Ltd
12	Licensee	holder of the Haryana Transmission and Bulk supply License.
13	EHT	Extra High Tension
14	HT	High Tension

2.2 Words and expressions used but not defined in these standards and defined in the Electricity (Supply) Act, 1948 (Act No. 54 of 1948), have the meanings respectively assigned to them in that Act;

2.3 Words and expressions used but not defined either in these standards or in the Electricity (Supply) Act, 1948 (Act No. 54 of 1948) and defined in the Electricity (Supply) Act, 1948 (Act No. 54 of 1948) and defined in the Haryana Electricity Reforms Act, 1997 (Act No.10 of 1998) and defined in the Indian Electricity Act, 1910 (Act No. IX of 1910), have the meanings respectively assigned to them in that Act;

Chapter-1

TRANSMISSION PLANNING AND SECURITY STANDARDS

1. OBJECTIVE

Transmission system planning shall be aimed at the system being capable of receiving power from the generating plants, CTU's and interconnecting points with the systems of neighbouring States, and transmitting the same up to the outgoing terminals of the transmission licensee's grid sub-stations, under established criteria, for operating the power system as an integrated whole.

2. TRANSMISSION PLANNING

2.1 Load Forecast and the power procurement Plan of the Licensee for the period under consideration shall form the basis of long term Transmission system planning for 10 years or above. The transmission system would be planned on the basis of regional self-sufficiency with an objective of dovetailing the Licensee's system into the regional power grid. The Licensee's system would operate in synchronism with generators, which may also include some captive power plants within the State and NREB system. All these elements shall, therefore, be included in the system modeling.

Keeping in view the future long term perspective plan, a detailed mid term transmission planning for a period of 5 years shall be carried out to ensure efficient investment plan and stating the objective of each of the project modules during the period under consideration.

2.2 System Modeling

2.2.1 Separate system models shall be developed for each year of a Plan Period to assess the need for commissioning a particular line in a particular year, based on the network, obtained for the year in question, with the generation and load buses properly located.

2.2.2 For modeling purposes, the interconnections with NREB at EHT levels shall be considered. An appropriate electrical equivalent shall be used to take into account the fault level at these interconnection points. Since these Buses will be represented as Generator Buses, generation and respective loads connected at these Buses shall be included in the modeling.

2.3 System Studies

2.3.1 The system shall be evolved based on detailed power system studies which shall include;

i. Load Flow Studies
ii. Short Circuit Studies
iii. Transient Stability Studies

These studies shall be carried out by suitable computer aided programme so that change in system performance could be studied in relation to system parameters on dynamic basis.

2.4 Load and Generation Despatches

2.4.1 Load

- All loads shall be modeled at 220kV or 132kV or 66 kV buses. The load for each bus would be obtained for any year within the plan period from the Load Forecast and a reasonable estimate of transmission losses shall be made to arrive at peak generation requirement. The annual minimum load shall be taken as a percentage of annual peak demand as prevailed in the base year.

- The MVAR loading at each Load Bus shall be assumed to be 50% of the MW loading taking average Power Factor of 0.90 Lag for peak and 0.95 lag for minimum load condition.

- Studies shall be carried out for Annual Peak Load, seasonal variation in peak loads and Minimum Load conditions.

2.4.2 Generation

- Generation availability in the state, its share in Joint /Central sector power stations and from any other reliable sources shall be considered for dispatches.
- For peak load conditions two generator despatches shall be used i.e., Maximum Hydro Generation and Maximum Thermal Generation.
- For the minimum load the 'must-run' generation shall be used in conjunction with the most economical thermal generation.
- The generation despatch for purpose of carrying out sensitivity studies corresponding to complete closure of a generating station close to a major load centre shall be worked out by increasing generation at other stations to the extent possible keeping in view the maximum likely availability at those stations, cost of power, etc.
- Special dispatches corresponding to high agriculture load with low power factor wherever applicable.
- Transmission constraints will be brought out and addressed.

2.4.3 Studies shall be repeated for Normal and Contingency conditions as specified under security standards.

2.5 Planning Criteria

2.5.1 Manual on "Transmission Planning Criteria" issued by Central Electricity Authority (CEA) shall be adopted with modification as stated below, particularly with reference to steady state voltage limits and security standards for withstanding outages.

2.5.2 Line Loading Limits

The permissible line loading limits shall conform to CEA's Manual on "Transmission Planning Criteria".

2.5.3 Options for Strengthening of Transmission Network

i. Addition of new Transmission lines to avoid over loading of existing system (wherever three or more circuits of the same voltage class are envisaged between two sub-stations, the next higher transmission voltage may be considered).

ii. Upgradation of the existing transmission lines.

iii. Application of series capacitors in existing transmission line shall be considered to increase its power transfer capability.

iv. Reconductoring of the existing AC transmission line with higher size conductors or with AAAC (All Aluminum Alloy Conductor) where ever applicable shall be considered.

v. Adoption of multiciruit and multi voltage level transmission lines.

The choice shall be based on cost, reliability, right of way requirements, energy losses, down time, etc.

2.5.4 Normally Double Circuit Towers shall be used for construction of all future lines. However, where only 2 circuit are planned for evacuation of power from a generating station, particularly thermal plants, these shall be 2x S/C lines.

2.5.5 Reactive power flow through ICTs shall be minimal and normally should not exceed 10% of rating of ICTs.

2.5.6 Steady State Voltage Limits

The transmission System shall be so planned as to maintain the steady State Voltage within the limits stated below.

Nominal Voltage (kV)	Maximum		Minimum	
	(%)	(kV)	(%)	(kV)
400	105	420	95	380
220	110	245	90	198
132	110	145	90	119
66	110	72.5	90	59.4

3. SECURITY STANDARDS

3.1 Steady State Stability

The system shall be planned to supply all loads during normal conditions and the following contingency conditions without necessitating load shedding or rescheduling of generation output as also to maintain voltage profile.

a) Outage of one transmission circuit or

b) Outage of double circuit line (in case of generating station)

c) Outage of one Interconnecting Transformer or

d) Outage of one Generator.

(Prior to such contingency, all elements shall be considered to be in service)

3.2 Transient Stability

3.2.1 The system shall be designed to maintain synchronism and system integrity under the following disturbances :

a. The outage of the single largest unit in the NREB system.

b. A permanent single line to ground (SLG) fault on a 400 kV/220 KV transmission circuit, single pole opening of the faulted phase (100 M.Sec or 5 cycles) with unsuccessful reclosure (dead time 1 sec.) followed by 3 pole opening (100 M.Sec) of the faulted line on a 400 kV transmission circuit (subject to note below).

Note: In order to facilitate simulation, a 3 phase fault with 5 cycle duration shall be considered for 400 kV circuit fault. Should the system survive this fault condition, it shall be assumed that system's stability is established. Should the system not survive this fault, then SLG fault criteria shall be applied.

c. The system shall be capable of withstanding a permanent fault on one of the circuits of a 400 kV D/C line when both circuits are in service and a transient fault when the system is already depleted with one circuit under maintenance/outage. Accordingly, 3-pole opening (100 msec) of the faulted circuit shall be considered when both circuits are assumed in operation and single pole opening (100 msec) of the faulted phase with successful reclosure (dead time 1 sec) when only one circuit is in service.

d. A permanent three phase fault with a duration of 160 m.sec (8 cycles) on a 220 kV or 132 kV Transmission circuit assuming 3-pole opening.

e. No stability studies need be made for radial lines.

4. SUBSTATION PLANNING CRITERIA

4.1 The rated rupturing capacity of the Circuit Breaker in any sub-station shall not be less than 125% of the maximum fault level at that sub-station. (The 25% margin is intended to take care of the increase in short circuit levels as the system grows). The standard rated breaking current capacity of switch gear at different voltage levels are as follows:

Voltage Level(kV)	Breaking Current(KA)
400	40 or 50*
220	31.5 or 40 *
132	25 or 31.5 *
66	25 or 31 *
(* The higher rupturing capacity shall be adopted for all new sub-stations).	

4.2 The capacity at any single sub-station at different voltage levels shall not normally exceed.

Voltage Level(kV)	Capacity (MVA)
400	1000
220	320
132	150
66	32

4.3 Size and number of interconnecting Transformers (ICT's) shall be planned in such a way that the outage of any single unit would not normally over load the remaining Interconnecting Transformers.

4.4 Reactive Power Compensation

4.4.1 Shunt Capacitors

Reactive compensation shall be provided as far as possible in the high voltage systems with a view to meet the reactive power requirement of load close to the load points. In the planning study the shunt capacitors required shall be shown at 132/220 kV Buses.

4.4.2 Shunt Reactors

Switchable shunt reactors shall be provided at 400 kV/220 kV sub-stations for controlling voltages within the limits specified. The step changes shall not cause a voltage variation exceeding 5%. Suitable Line Reactors (Switchable/Fixed) shall be provided to enable charging of 400 kV lines without exceeding voltage limits specified.

5. General

i) While planning, the transmission lines for power supply in urban area and other areas where the Right –Of –Way (R-O-W) constraint could be anticipated, long term requirement may be taken into account and all the lines shall be planned as D/C lines using twin conductor of higher than the conventional size. This approach would help in avoiding the Right –Of –Way problems later on.

ii) In urban (high population density) areas, availability of land and possibility to its encroachment are the major problem being faced by most of the power utilities. In order to tackle this problem, it is suggested that land might be acquired for sub-station requirements anticipated in long term and few approach towers from the sub-station may be constructed as D/C towers to prevent encroachment and overcome difficulty in obtaining R.O.W. in future.

Chapter-2

POWER SUPPLY SECURITY PLANNING STANDARDS

1. OBJECTIVE

Power Supply Planning is to aim at a least cost generating capacity expansion planning to serve the demand at a specified level of reliability.

2. POWER SUPPLY PLANNING

Long term power supply planning shall be made based on Load Forecasts prepared pursuant to Condition 19.10 of the Haryana Transmission and Bulk Supply License. The Licensee shall abide by conditions of GRIDCODE in formulating its long-term load forecasts. The planning process shall take into account the existing contracted generation capacity, allocation from Central Sector Generation in the base year and from any future committed project and evolve the net additional requirement of power over the years during the plan period. The planning process shall also consider an extended study period of twenty years beyond the study period of ten years to smoothen out the "END Effects" due to different types of generation capacity at the end of the study period.

3. PLANNING CRITERIA

3.1 Peaking Availability

The peaking availability of existing Hydro Electricity Plants and Thermal Plants shall be in accordance with data furnished by the respective Generating Companies and also as per the Power Purchase Agreements made with respective power stations. Availability from Central Sector Plants shall be taken as allocated by the Government of India. For the new plants, peak availability shall be as per Central Electricity Authority norms or as per the power purchase agreements with the respective Generating Companies.

3.2 Plant Availability, PLF and Outage rate

The following norms for plant availability and PLF shall be used in the simulation studies

Unit type	Availability % (ex-bus)		PLF %	
	New units	Old units	New units	Old units
A. Coal based plants				
500 / 250 MW units	80.0	80.0	75.0	75.0
200/210MW units	76.0	76.0	68.5	68.5
Less than 200 MW units	76.0	60.0	68.5	45.0
B. Gas turbines				
CCGT	85.0	85.0	68.5	68.5
OCGT	85.0	85.0	33.0	33.0
C. Nuclear				
500 MW units	80.0	----	75.0	----
220 MW units	76.0	76.0	68.5	68.5
D. Diesel units	85.0	85.0	33.0	33.0
E. Hydro units	90.0	90.0	--	--

The following outage rates for plants shall be used in the simulation studies.

Unit Type	Planned Outage		Outage (Forced +Partial)	
	(Days/yr)	(%)	(Days/yr)	(%)
A. Coal based plants				
500 / 250 MW units	35	9.6	38	10.4
200/210MW units	35	9.6	52	14.2
Less than 200 MW units				
New Units	35	9.6	52	14.2
Old units	56	15.3	90	24.6
B. Gas turbines/ Diesel	35	9.6	20	5.5
C. Nuclear				
500 MW units	42	11.5	31	8.5
220 MW units	42	11.5	45	12.3
D. Hydro units	21	5.8	15	4.1

[Note: i) Units commissioned before 01.04.1998 shall be considered as old units.]

3.3 Auxiliary Consumption

Auxiliary consumption in plants for the purpose of planning studies shall be follows:

	Description	Plant Size/Type	Auxiliary Consumption
1.	Coal based Thermal Plants	i) 500/250MW ii) 200/210 MW iii) Less than 200 MW	8.0% 9.5% 10.5%
2.	Gas turbines	i) CCGT ii) OCGT	3.0% 1.0%
3.	Nuclear Plants	i) 500 MW ii) 220 MW	8.0% 10.5%
4.	Diesel Station	All sizes	4.0%
5.	Hydro Station	i) unit auxiliary ii) transformation losses	0.5% 0.5%

3.4 Heat Rate

Gross heat rates for the generation units for the purpose of planning studies shall be used as follows:

S.N.		Gross Heat rate (KCal/ KWh)
1.	Steam Thermal	2500
2.	Gas turbine	
	CCGT	2000
	OCGT	2900
3.	Diesel plants	2000

Note: In case of any difference, the actual heat rate as specified by the Generating Company shall be adopted.

3.5 Secondary fuel oil consumption @ 3.5 ml / kWh shall be taken for coal based plants.

3.6 Economic Parameters

3.6.1 The cost estimate shall reflect economic conditions as on 1st April of the Base Year. The cost shall increase overtime at the rate of general inflation and shall exclude taxes and duties in so far as they are common in the economic evaluation. If the costs are considered to be financial costs, all taxes and duties shall be included

3.6.2 Plant Economic Life

The economic life of Generating plants may be assumed as follows for the planning studies in accordance with Govt. of India notification made under sub paragraph (A) of Paragraph VI of VI Schedule to Electricity (Supply) Act, 1948, from time to time.

Plant Type	Life (Years)
Hydro Electric	35
Thermal	25
Gas Turbine	15
Diesel sets	15
Nuclear	25

3.6.3 Cost of Unserved Energy

Value of unserved energy (i.e. the loss to the economy if a KWh of energy required by consumers cannot be supplied) shall be considered in the economic analysis for the least cost generation expansion plan. Suitable pricing for such power outage costs shall be adopted from available studies applicable to Haryana.

3.7 Evaluation of Planning Studies

3.7.1 Suitable computer aided programming model/ program shall be adopted to arrive at a least cost generation expansion plan.

3.7.2 The economic evaluation shall be carried out in accordance with the guidelines enumerated below

i. Set out different generation expansion scenario incorporating available proposals mixed hydro/thermal expansion, only thermal expansion, mixed base/peak generation expansion, in the context of demand forecast.

ii. For each scenario, determine through simulation, the timing of new installations during the planning period in order to meet the planning criteria.

iii. Simulate the system operation in order to obtain the average annual energy production from each hydroelectric plant and each thermal plant.

iv. Compute the cumulative present value cost for the scenario over the planning period incorporating capital costs for new generation and associated transmission, fixed and variable operation and maintenance costs, fuel costs and unserved energy costs.

v. Compare the present value cost of each scenario with that of the other to arrive at the least cost scenario.

vi. Calculate the Long Run Marginal Cost for the least cost scenario as follows:

   a. For each year of the plan period determine incremental cost of generation, transmission, energy requirement, energy generated, unserved energy, incremental net energy generated, loss of load probability in hours, unserved energy percentage.

   b. Work out the incremental cost of generation to the Net Present Value.

   c. Long Run marginal cost in Rs/KWh is = [Total net present value of incremental cost of generation and transmission (Rs.)] / [Incremental net energy generation (KWh)].

4. POWER SUPPLY SECURITY STANDARDS

To ensure that the generation reserve is sufficient so that the system can meet the load considering scheduled maintenance of all the units in the system and forced outage of one largest unit in the system or in the event of non-availability of adequate hydro-electric generation capacity during the dry period, adequate reserve capacity shall be built into the system both for capacity and energy.

4.1 Capacity Reserve

Loss of Load Probability (LOLP) of 2% shall be used for planning models. This shall mean that for 2% of the time of the year (i.e., up to 175 hours/year) there is a probability that the system demand exceeds the available capacity. The required capacity would be adequate to meet the power supply security standards. However, optimal LOLP may be calculated for the Haryana System.

4.2 A contingency reserve margin equal to 5% of the system peak load, besides normal reserve margin corresponding to 2 % LOLP and 0.15% ENS shall be planned to take care of fluctuations in the availability of Hydro Electric generation during the critical period of February to June of a dry- year, and to account for outages of units, power station equipment, non-availability of Central Sector share in order to maintain security and integrity of the system.

4.3 Energy Reserve

"Energy Not Served" shall be limited to 0.15% of the average annual energy demand.

Chapter-3

TRANSMISSION OPERATING STANDARDS

1. OBJECTIVE

These standards are laid down for operating the transmission system so as to provide an efficient, coordinated and economical system of electricity transmission.

2. DATA MANAGEMENT

The following data relating to the Transmission System shall be recorded and maintained by the licensee. The data where ever possible shall be online or recorded at an interval of half an hour (or as per the IEGC requirement).

i. Line data
ii. Transformer data including Generation transformers
iii. Bus Data including that of Generating stations
iv. Availability and outage data of important transmission elements e.g. transmission line, transformer etc.
v. Generator data including that of Captive Power Plant running in parallel with the grid
vi. Demand data including loading and power factor for each EHT sub-station

3. LOAD DESPATCH

3.1 The State Load Dispatch Center (SLDC) would run round the clock for the purposes of :

i. Daily Generation Scheduling and issuing of despatch instructions.
ii. Monitoring line MW and MVAr drawals, EHT Bus voltages for important lines /substations, system frequency and other system operation parameters.
iii. Monitoring Generation output.
iv. Coordinating restoration process after total or partial blackouts in the Transmission System or Regional System.
v. Giving direction and exercising such supervision and control as may be required for ensuing the integrated grid operation and for achieving the maximum economy and efficiency in the operation of power system of the licensee.
vi. Ensuring that all directions issued by SLDC/Regional Load Dispatch Center are duly compiled with.
vii. Enforcing the decisions of Regional Electricity Board.

4. COMMUNICATION

4.1 A reliable and efficient point to point voice and data communication links would be set up between the SLDC, NRLDC, Generating Stations and grid sub-stations.

4.2 All operational communications/instructions transmitted by SLDC or transmitted to SLDC would be recorded as evidence of the communications /instructions.

5. OUTAGE PLANNING

The plan for outage of circuits / Transformers required for maintenance, construction, modification, diversion, etc. would not violate the security standards of Transmission system.

Overall outage Planning for the Region is coordinated by Northern Regional Electricity Board. The responsibility of licensee for Outage Planning includes:

i. The licensee shall provide REB Secretariat their proposed outage programme in writing in consultation with SLDC for the next financial year by 30th November of each year. These shall contain identification of each line/ICT, the preferred date for each outage & its duration and where there is flexibility, the earliest start date and latest finishing date.

ii. Final outage plans prepared by REB will be reviewed from time to time in Regional forum and will be implemented accordingly.

iii. Licensee shall obtain the final approval from SLDC prior to availing an outage.

6 SYSTEM STUDIES & PROTECTION

6.1 The system studies including load flow studies and Transient stability studies would be carried out as often as required but at least once a year.

6.2 The settings of the Relays in the Protection Schemes of the Transmission system would be coordinated with those of the Generators, BBMB, PGCIL and grid system of neighboring States at respective points of interconnections.

6.3 The user of the Transmission System would be intimated the computed fault level of the Transmission system at the point of interconnection so as to coordinate the equipment ratings appropriately.

7. LOAD MANAGEMENT

7.1 The MW/MVAR loadings on each transmission line and each interconnecting transformer would be monitored on real time basis locally at each sub-station as well as at SLDC. Similarly loading on each transformer at grid sub-stations would be closely monitored during peak load hours.

7.2 If any system component is being over loaded, the same would be reduced to avoid breakdown of the equipment/system.

7.3 Load management will be carried out as per instructions of SLDC through

i. Manual load disconnection/reconnection.

ii. PC based system for rotational load shedding with facilities for central programming and uploading of the disconnection schedule for the day from the SLDC/sub-LDC to the substations.

7.4 During the demand control by manual disconnection of loads by staggering in different groups, the roster changeover from one group to another shall be carried out in a gradual and scientific manner so as to avoid excursions in the system parameters.

8. VOLTAGE MANAGEMENT

8.1 The voltage levels at all EHT sub-stations of its Transmission System would be monitored on real time basis at SLDC.

8.2 Since voltage is affected both by frequency and reactive power flow, efforts would be made to maintain system voltage by taking all possible measures to regulate system frequency and reactive power flows.

8.4 All local voltage problems would be addressed by operating local transformer taps and/or switching capacitor banks etc.

8.5 In the event of system high voltage the following specific steps would be taken by the licensee's grid substations at their own, unless specifically mentioned by SLDC otherwise;

- The bus reactors be switched in
- The manually switchable capacitor banks be taken out
- The switchable line/tertiary reactors be taken in
- Opening of the light loaded lines in consultation with SLDC, keeping in view the security of the balance network.
- Reducing taps of 220 kV, 132 kV and 66 kV interconnecting transformers.

8.6 In the event of system low voltage the following specific steps would be taken by the licensee's grid substations at their own, unless specifically mentioned by SLDC otherwise;

- The bus reactors be switched out
- The manually capacitor banks be switched in
- The switchable line/tertiary reactors be taken out
- Closing of the lines which were opened to control high voltage
- Increasing system voltage by tap changing of 220kV, 132 kV, and 66kV interconnecting transformers.
- Restoration of circuit under outage.
- Demand reduction.

8.7 At the interchange points where licensee system is connected with Regional grid, licensee shall endeavors to minimize the VAR drawal when voltage is below 95% of rated, and shall not return VAR when the voltage is above 105%.

8.8 The licensee will operate on-load and off-load taps of power transformer and interconnecting transformer at each EHT sub-station in the Transmission system as and when necessitated by system requirement.

8.9 Switching in/out of all 400 kV Bus and line reactors throughout the grid shall be carried out as per instruction of RLDC. Tap changing on all 400/220 kV ICTs shall also be done as per RLDC instructions.

9. AUTOMATIC LOAD SHEDDING DURING UNDER FREQUENCY AND BACKING DOWN DURING HIGH FREQUENCY

9.1 Under Frequency relay load shedding scheme shall conform to that formulated and reviewed by NREB from time to time in consultation with all the constituents based on both flat frequency as well as rate of change of frequency. The scheme would ensure no overlapping between areas covered by UF relay load shedding and that included in the manual load shedding plan as part of demand control. The licensee would ensure to keep all the UF relays properly maintained and functional so that automatic relief through these relays would be available to the system under all conditions. As per directions of SLDC, under normal system operation, frequency should not fall to such low value necessitating unnecessary operations of U/F relays. Manual load shedding should be carried out as directed by SLDC to avoid such situations. The automatic load shedding operation of UF and df/dt relays is meant to take care of unforeseen contingencies and should occur only in case of sudden loss of bulk generation.

Licensee shall furnish to NRLDC/SLDC a list of feeders connected for UFLS, UF settings and load relief quantum etc. and shall furnish a monthly report on availability and condition of UFRs in the system under the control of licensee.

9.2 When the system frequency is beyond 50.2 Hz, the generating units with high variable cost of generation shall be advised to back down their generation and even shut down in case the frequency continues to remain high, at the directions of NRLDC, who co-ordinate integrated grid operation.

10. ISLANDING SCHEME

10.1 To avoid total black out of the grid, during system disturbances and for early normalization, an islanding scheme involving major generating stations and part(s) of the transmission system would be developed in consultation with NRLDC.

10.2 When an exporting group is islanded, the frequency of the islanded group would be controlled below 50.5 Hz by load pick up within the island or reduction of generator outputs and, if necessary, by generator tripping.

10.3 When an importing group is islanded and the frequency of the group is below the specified lower limit, the islanded group would improve the frequency to the security limit by increasing generator output and, if necessary, by load shedding.

11. SAFETY COORDINATION

11.1 The General Safety Requirements as laid down in I.E. Rules for construction, installation, protection, operation and maintenance of electric supply lines and apparatus shall be observed.

11.2 Suitable control person(s) shall be designated for coordination of safety procedures before work is taken up, during work, and after work is completed till the concerned system component is energised, both inside its own Transmission System and across a control boundary between Licensee's Transmission System and that of any User.

11.3 A Safety Manual for the purpose of Safety Coordination shall be developed.

12 EVENT REPORTING

12.1 All abnormal occurrences or events affecting the operation of system requiring attention would be monitored and logged by the licensee who shall be responsible for reporting events to SLDC. Following events are to be reported:-

(i) System islanding/system split.
(ii) System black out/partial system block out.
(iii) Protection failure on any element of transmission system
(iv) System instability
(v) Tripping of any element.

12.2 Reporting Procedure:

(a) Written reporting of Events by Licensee to SLDC

In the case of an event which was initially reported by a Licensee to SLDC orally, the Licensee will give a written report to SLDC in accordance with (b)

(b) Form of written Reports:

A written report shall be sent by licensee to SLDC and will confirm the oral notification together with the following details of the event:

i) Time and date of event
ii) Location
iii) Plant and/or equipment directly involved
iv) Description and cause of event
v) Antecedent conditions
vi) Demand interrupted and duration of interruption
vii) Sequence of tripping with time
viii) Details of Relay Flags
ix) Remedial measures

13. POST DISTURBANCE ANALYSIS

13.1 The licensee will provide all information/data and assist SLDC/NRLDC in post disturbance analysis.

13.2 Recording instruments such as disturbance recorder/Event logger/Fault locator (including time synchronisation equipment) shall be provided at all the identified major grid substations to facilitate in identifying sequence of the event etc.

14. MAINTENANCE, STANDARDISATION, SPARES, TESTING AND INSPECTION

14.1 Maintenance schedules of lines and sub-station equipment shall be developed in conformity with I.E. Rules, relevant CBI & P manuals and manufacturer's recommendations.

14.2 A hierarchy shall be established for implementation of the maintenance standards and its monitoring.

14.3 No transmission line shall suffer total interruption for more than 175 hours in a year, including planned outages but excluding Force Majeur causes.

14.4 For the purposes of reducing inventory, procurement time, installation time, standardised designs shall be adopted for Transmission Line Towers, Structures for sub-stations, standardise layouts for sub-stations, sub-station lighting, Control Room lighting and ventilation, sub-station earthing. Standard specifications shall also be prepared for line materials, transformers, sub-station equipment, Cables, Bus bar accessories, insulators and hardware etc.

14.5 For expeditious maintenance, repair and replacement of line equipment and sub-station equipment, recommended spare parts and equipment shall be procured and adequate inventory of long delivery spare parts shall be maintained.

14.6 Routine Testing of Relays, Meters, Current-Transformers, Potential Transformer, Condenser Bushing, and other electrical accessories used in sub-stations shall be done in the Electrical Testing Laboratories of the licensee in accordance with relevant Indian Standards and Manufactures instructions.

14.7 All field tests and Commissioning tests of sub-station equipment such as Transformer, Circuit Breaker, Current Transformer, Potential Transformer, Station Battery, relays and meters, Control Wiring, Cables, Lightning Arrester, sub-station earthing, etc shall be by the testing organisations of the licensee.

14.8 All necessary equipment, tools & tackles, etc. shall be maintained in good condition for carrying out maintenance of lines and sub-stations equipment and ensure their availability at all sub-stations.

14.9 Periodical inspection of all lines and sub-stations shall be carried out through an independent inspection team, qualified for the purpose, to ensure that maintenance of lines and sub-stations are carried out as per maintenance schedules.

Chapter-4

POWER SUPPLY OPERATING STANDARDS

1. OBJECTIVE

These standards set in levels of operational security and quality of supply, which the Licensee shall be obliged to maintain in making power available for the purposes of supply to consumers, as laid down in condition 19.4(a) of the Haryana transmission and Bulk Supply License, 1999.

2. OUTAGE PLANNING

The generation output shall be matched with estimated demand taking into account the Transmission/Generation outages so as to achieve the Transmission and Power Supply Security Standards. The provisions in the GRID CODE shall be followed to achieve coordination between Transmission Outage Programme and Generation Outage Programme.

3. GENERATION SCHEDULE AND DESPATCH

3.1 The following factors shall be taken into account while preparing the Generation Schedule and Despatches.

i. System Demand
ii. Merit Order Operation of Generating Units
iii. Availability of Generating Units
iv. Constraints on the Transmission System
v. Security Requirements
vi. System Losses

However, the System Security and Stability shall have precedence over and above the merit order of operation.

3.2 The Generation Schedule and their despatches shall be accordingly prepared on 15 minute block day ahead basis, on the basis of data provided by Generators and CPP's and in consultation with NRLDC regarding allocated drawal for the day from Central Sector Generating Stations. The day ahead generation schedule shall be communicated to the Generators and NRLDC in the manner out lined in GRIDCODE.

3.3 Appropriate spinning reserve shall be achieved by making suitable allocations to specific generating stations in consultation with NRLDC.

4. FREQUENCY MANAGEMENT

4.1 The system shall normally be maintained within a Frequency range of 49.5 to 50.5 Hz by adhering to the following steps:

i) Licensee shall regulate the load/own generation under its control so that it may not draw more than its net drawal schedule during low frequency conditions and less than its drawal schedule during high frequency conditions.

ii) In case licensee is likely to face power shortage situation despite requisitioning its full entitlement from Central sector, it shall endeavor to enter into a bilateral agreement with the other state constituents having a power surplus and vice-versa. In any case, during low frequency conditions licensee would not resort to overdraw.

iii) Sudden reduction in generator output by more than one hundred (100) MW except in an emergency condition or to prevent an imminent damage to the equipment shall not be carried out without prior intimation and consent of the NRLDC, particularly when frequency is falling below 49.0 Hz.

iv) Sudden increase in load by more than 100 MW by the licensee, particularly when frequency is falling below 49.0 Hz and reduction in load by such quantum when frequency is rising above 50.5 Hz shall not be carried out without prior intimation and consent of the NRLDC.

4.2 The licensee shall be vigilant when frequency begins to rise above 50 Hz and initiate following measures to bring down the frequency to about 50 Hz.

i. Check generation scheduling vs generation and request concerned Generator with excess generation to conform to generation schedule.

ii. Advise Hydro Stations to reduce generation without water spillage.

iii. Back down thermal stations to the extent of norms decided by NRLDC/NREB from time to time.

4.2.1 In case Frequency rises to 50.5 Hz. inspite of above measures, the coal fired Thermal Stations having 210/500 MW units shall be advised to bring down generation to bare minimum using oil support or if necessary to shut off below 210 MW sets.

4.2.2 In case the Frequency still rises above 50.5 Hz and does not fall below 50.8 Hz, the system shall be islanded, in consultation with NRLDC, from rest of NREB if there is import at points of interconnections. However before doing so all efforts would be made so that no part of the grid is deliberately isolated from the rest of the Regional Grid, except (i) under an emergency, and condition in which such isolation would prevent a total grid collapse and/or enable early restoration of power supply, (ii) when such isolation is specifically instructed by NRLDC. Complete synchronization of grid shall be restored as soon as the condition again permits it. The restoration process shall be supervised by NRLDC, as per operating procedure separately formulated.

4.3 When Frequency begins to fall below 49.5 Hz following measures should be initiated

to raise the System Frequency to about 50 Hz.

i. Check generation scheduling Vs. generation and request concerned Generator with less generation to conform to generation schedule.

ii. Check whether there is any excess drawal at any points of interconnection by any Distribution and Retail Supply License and advise to restrict its drawal within Schedule.

iii. Advise Hydro Stations to synchronise stand by machines, if available.

4.3.1 In case the Frequency still falls and reaches 49.0 Hz the Distribution Licensees shall be advised to shed load manually in predetermined blocks.

4.3.2 In case the Frequency still continues to fall and reaches 48.5 Hz, the system shall be islanded, in consultation with NRLDC, from rest of NREB if there is export at points of interconnection.

5. STANDARDS TO BE MET BY GENERATORS

5.1 While contracting Bulk Power Supply from Generators, voltage and frequency standards with limits of variation shall be specified in the Power Purchase Agreement, which the Generator has to accommodate.

5.2 The following conditions shall be incorporated in the Power Purchase Agreement requiring the Generators to commit:

a. Spinning Reserve Response during Frequency transients at different load levels.
b. Reactive power capability (MVAR).
c. Economic back down level.
d. Loading increment rate from back down level to maximum continuous Rating (MW/min).
e. Loading decrement rate from maximum continuous rating to back down level (MW/min).
f. Pick up rates on synchronising in MW/min under conditions of:
    i. Cold start
    ii. Warm start
    iii. Hot start
g. that the generator shall abide by the provisions in GRID CODE to the extent that it does not jeopardise safety of its plant and personnel.

5.3 (i) Free Governor Mode of Operation: Licensee would ensure that the generating units synchronized with the grid are operated on free governor mode of operation and with necessary primary and secondary control in line with relevant sections of IEGC.

(ii) AVRs Control: All generating units shall normally have their Automatic Voltage Regulators (AVRs) in operation, with appropriate settings. In particular, if a generating unit of over fifty (50) MW size is required to be operated without its AVR in services, the NRLDC shall be immediately intimated about the reason and duration, and its permission obtained. Power System Stabilser (PSS) in AVRs of generating units (wherever provided) shall be properly tuned as per a plan prepared for the purpose by the Central Transmission Utility (CTU) from time to time. CTU will be allowed to carry out tuning/checking or PSS wherever considered necessary.

6. GENERATION RESERVE

6.1 The necessary capacity and energy reserves shall be planned for in accordance with Security Standards.

6.2 These reserves shall be allocated to the Generators in the following manner:

Contingency Reserve (i.e. The operating reserve, which will respond to the disturbance condition following the most severe single contingency.)	On month ahead basis
Spinning Reserve (i.e. the operating reserve, which will automatically respond to the frequency deviation.)	on day ahead basis

7. MONITORING OF GENERATION

7.1 The SLDC shall be equipped to receive the following real time data from Generators:

i. Frequency
ii. MW output
iii. MVAR output
iv. MW and MVAR flow in outgoing lines
v. Voltage at interconnection Bus

7.2 A procedure shall be established for monitoring the following parameters of a generation plant :

i. Declared Gross Generation Capacity
ii. Loading rate of a Unit
iii. De-loading rate of a Unit
iv. Active and Reactive power delivery following Despatch instructions.
v. Capability of Generating plant to meet Spinning Reserve requirements.