WORKSHOP ON
GRID SECURITY IN OPEN ACCESS REGIME

08th –09th August 2007
Banaras Hindu University, Varanasi

Approach Paper for

Assessment

of

Transfer Capability

in the

Indian Bulk Electric Power System

Power Grid Corporation of India Limited
(Corporate System Operation Division)

New Delhi, India
August 2007

Table of Contents

List of Tables

Synopsis

The electricity grid in India is a conglomeration of the power systems owned by various utilities in the state and the central sector. There are five regional grids namely North, West, East, Northeast and South. First four out of above five regional electricity grids in India are operating in a synchronous mode[1] since 26th August 2006. The regional grids are operated as loose power pools with decentralized scheduling and despatch, in which the states have full operational autonomy. The Regional Load Despatch Centre (RLDC) is the apex body to ensure integrated operation of the power system in the concerned region while the State Load Despatch Centre (SLDC) is the apex body to ensure integrated operation of the power system in the concerned state.

Assessment of transfer capability is important for operation of the integrated power system in a secure manner and is therefore a *de-facto* responsibility of the Load Despatch Centres. Computation of transfer capability is also required for facilitating non-discriminatory open access in transmission system as mandated by the Electricity Act 2003. These figures have to be worked out in a realistic fashion so that neither the security of the grid is compromised nor the scope for economy interchange reduced unduly. Calculations must take into account, among other factors, the network topology, planning criteria, operating philosophy, operating standards, market design, generation dispatch, spatial distribution of load/generation, behaviour of the utilities and the peculiarities of the Indian electricity grid.

The awareness and understanding of the concepts associated with transfer capability is still in a nascent stage in India. International literature provides a good reference for understanding the basic concept of transfer capability. However the discussions in those papers hover around the grids in developed countries with a socio-economic, political and regulatory set up different from those existing in India. Therefore application of the concept in the Indian electricity market requires a thorough understanding of the grid operation philosophy adopted in India besides the finer nuances of the concept itself.

This paper presents the knowledge gathered from literature survey on the subject and proposes an approach for its implementation in the Indian context. It attempts to answer the following questions relevant in this regard:

1. **What is transfer capability of the power system?**
2. **How is transfer capability different from transmission capacity?**
3. **What are the considerations for assessment of transfer capability?**
4. **How is transfer capability assessed?**
5. **What is reliability margin and why is it required?**
6. **What are the risks associated with violation of transfer capability in real time?**
7. **What are the methods for enhancing transfer capability of Indian bulk electric power system**

The paper comprises of nearly 50 pages and is organized in seven chapters. **Chapter-1** dwells on the definition of transfer capability and elaborates how transfer capability is different from transmission capacity. **Chapter-2** discusses the various considerations for assessment of transfer capability viz. planning criteria; operating limits; network topology and reliability margins. **Chapter-3** discusses the features that distinguish Indian grids from the grids in other countries. The implications of these distinguishing features on the reliability of power system and the consequent need for reliability margins have been elaborated. It also highlights the consequences of not providing for reliability margins in the Indian context. **Chapter-4** consolidates the methodology for assessment of transfer capability in the Indian context. Chapter-5 discusses the risks associated with violation of available transfer capability. **Chapter-**

---

[1] The synchronous North_East-West grid may be designated as "NEW grid"

6 discusses about a few methods for enhancing transfer capability of the Indian bulk electric power system. The efforts being made for implementation of these methods in India are also summarized. **Chapter-7** contains the conclusions of the discussion and the suggestions for the future.
Last section of the paper carries acknowledgements and list of references.

Queries, suggestions, comments if any on the paper may be addressed to

S. K. Soonee
Executive Director, Corporate System Operation
Power Grid Corporation of India Limited
18-A, Shaheed Jeetsingh Sansanwal Marg
Qutub Institutional Area
New Delhi-110016
Email: sksoonee@powergridindia.com, sksoonee@gmail.com

Acknowledgement

This paper is a culmination of collective efforts during the last one-year. Several rounds of discussions on the subject were held in the Regional Power Committee and the various subcommittee meetings. The question uppermost in the minds of many stakeholders was the issue of transmission corridor available for trading power across the region. This gave us the inspiration to explore the issue in greater detail. Extensive debates, videoconferencing sessions and web group discussions took place between RLDC engineers. The above process led to a series of workshops on the subject organized in each region where all stakeholders participated and gave valuable feedback. We would like to thank all the organizations and individuals who participated in this process and helped in crystallizing the ideas on the subject. The contribution made by Shri S. R. Narasimhan, Shri Rajiv Porwal and Shri Vivek Pandey from NRLDC in capturing the ideas generated, carrying out literature survey, and drafting the paper in its present form is acknowledged.

Special thanks to Shri Mata Prasad, FNAE, Shri K. Ramanathan, Distinguished Fellow, TERI and Dr. S. Mukhopadhyay, Chief Engineer, CEA and Senior Member, IEEE for reviewing the initial draft and providing valuable comments.

We were privileged to have Dr. Anjan Bose, Professor Emeritius, Washington State University at NRLDC, New Delhi during his brief visit to India in Dec 2006. We thank him for sharing his experience on reliable operation of electricity grids and guiding us in documenting our experience in this area.

POWERGRID Corporate System Operation division also acknowledges the leading role of Ministry of Power, CEA and the CTU in development of the Indian bulk electric power system. The documents and technical literature developed by them provided for a solid foundation for this paper.

We would like to thank Shri Bhanu Bhushan, Member CERC for his interest and encouragement in reliable operation of the Indian electricity grids.

Corporate System Operation Division expresses gratitude to the POWERGRID management for their continuous encouragement and support.

6th August 2007

(S. K. Soonee)
Executive Director (SO & NRLDC)
Corporate System Operation Division,
POWERGRID, New Delhi, INDIA

Chapter-1

Transfer Capability

1.1 Introduction

Bulk electric power systems comprise of hundreds of generating units interconnected by an intricate web of transmission & distribution spread across vast geographical stretches. These systems are dynamic in nature by virtue of their inherent characteristics and continuous exposure to human, environmental and other physical influences.

Providing a reliable supply of electricity is an enormously complex technical challenge, even in most routine of days. It is said that the power supply to the consumers is the ultimate 'just-in-time' manufacturing..."*Capable of moving at almost the speed of light, the product is delivered to the customers fresh, within milliseconds of being 'manufactured' by the generators...The customers are in complete control of the amount of product they use...They never get placed on hold...So the generators must continually match the load, even though daily fluctuations in demand of more than 100 percent are not uncommon...*" [1].

For ensuring a reliable and quality supply to the consumers, the power system must be operated within the prescribed reliability standards. This is achieved through extensive off-line as well as real-time coordination between thousands of personnel in-charge of various activities of the electricity supply chain viz. generation, transmission and distribution. The system operators positioned at well-equipped control centres provide the coordination services that are vital for operating the system within the operating limits. In this context it becomes imperative to understand the concept of transfer capability and the implications of the operating philosophies and prevailing grid conditions on transfer capability.

1.2 Definition of Transfer Capability

For the purpose of operational jurisdiction, management control and commercial ease, the power system is demarcated into control areas. Electricity however does not recognize man-made boundaries. By virtue of its characteristics, it flows seamlessly in the interconnected network irrespective of asset ownership or operational jurisdiction. When power is transferred between two control areas, the entire interconnected network, irrespective of the ownership, responds to the transaction. In fact the power flow on each transmission path changes in proportion to the response of the path to the transfer. This response is determined by the network topology, spatial distribution of generation, spatial distribution of customer demand and other transactions through the area. Thus individual transmission paths when used in a live network interact in a dynamic fashion.[2] The collective response of all the elements (having different individual capacities) in a network determines the "permissible power flow" across various sections of the network. This **"permissible power flow"** is often termed as transfer capability of the network.

In other words the Transfer Capability of a transmission network is the ability to transfer electric power when operated as part of the interconnected power system and may be limited by the physical and electrical characteristics of the systems. The limiting condition on some portions of the transmission network can shift among thermal, voltage and stability limits as the network operating conditions change over time.

---

[2] This is one phenomenon among others that distinguishes electrical networks from other cybernetics.

1.3 Difference between Transfer Capability and Transmission Capacity

‘Transfer Capability’ is the measure of the ability of interconnected electric systems to reliably move power from one area to another over all transmission lines (or paths) between those areas under specified system conditions. It is directional in nature and is highly dependent upon the generation, customer demand and transmission system conditions assumed during the time period analyzed. Transfer Capability may be limited by the physical and electrical characteristics of the systems. The limiting condition on some portions of the transmission network can shift among thermal, voltage and stability limits as the network operating conditions change over time.

Transfer Capability is different from ‘Transmission Capacity’, which usually refers to the thermal limit or rating of a particular transmission element or component. The individual transmission line capacities or ratings cannot be arithmetically added to determine the transfer capability of a transmission path or interface. In fact the actual transfer capability of the network is often less than the aggregated transmission capacity of the individual circuits of a specific transmission interface between two areas of the network.[3] The distinguishing features of transmission capacity and transfer capability are tabulated below:

Table 1 :Transmission Capacity vis-a-vis Transfer Capability

S No.	Transmission Capacity	Transfer Capability
1	Is a physical property in isolation	Is a collective behaviour of a system
2	Depends on design only	Depends on design, topology, system conditions, accuracy of assumptions
3	Deterministic	Probabilistic
4	Constant under a set of conditions	Always varying
5	Time independent	Time dependent
6	Non-directional	Directional
7	Determined directly by design	Estimated indirectly through simulation studies
8	Declared by designer/ manufacturer	Declared by the System Operator
9	Generally understood	Frequently misunderstood
10	Considered unambiguous & sacrosanct	Subject to close scrutiny by all Stakeholders

The difference between transfer capability and transmission capacity and its impact on the interchange scheduling limits could also be understood through the following illustration.

Illustration

Suppose a control area has a total transformation **capacity** of 3260 MVA (Transmission capacity) at the super grid level. The **capability** to meet load (transfer capability) would however depend on several other factors such as spatial distribution and diversity of generation/load, network configuration (radial or meshed), availability of reactive compensation within that control area. Thus the transmission capacity here is 3260 MVA but the transfer capability would vary considerably with the prevailing conditions. The utility might choose to operate its power system close to transmission capacity by serving its consumers in a radial fashion. This would however entail huge coordination costs besides poor reliability of supply

---

[3] For instance we might have an eight-lane expressway between Delhi and Jaipur and a Ferrari driven by a Formula-I racer. Each may have the capacity to operate at a speed of 300 km/hour. Still it would not be possible to cover the 265 km distance between Delhi and Jaipur in less than one hour due to various bottlenecks, road intersections disturbances on the way. In fact it could take as high as three hours giving an average speed of 88 kms/hr (the system capability), which is only 30% of the design capacity.

(high Loss Of Load Probability on account of transmission), poor quality of power supply in terms of voltage regulation and substantial increase in transmission losses.

Transfer capability of the network is heavily dependent on the network response to the various transactions between control areas in the system. The sharing of power by each element in the corridor (also known as distribution factor) is not equal. This implies that the transfer capability of a corridor cannot be determined by arithmetic sum of individual transmission capacities of all parallel transmission lines in that corridor. As the power transfer across the section is increased one or more elements could hit the limiting value before the others. The total power transfer across the section would therefore have to be restricted to the value at which the first element reaches the limiting value. If the loading on each parallel element is balanced with the help of series compensation the transfer capability could be enhanced. However it would be seen that the transfer capability would vary depending upon whether the series compensation is in service or out of service during the period for which the transfer capability assessment is being carried out. The network limitations are also not constant and are time dependent. Very often if we solve any problem in one part of the network, the problem shifts to another part of the network. This is a common problem particularly with FACTS devices. [4].

Table 2: Sample Distribution factor for transmission lines associated with Nathpa Jhakri evacuation system in Northern Region

Contingency Label →				Basecase	Outage of Jhakri-Abdullapur	Outage of Jhakri-Nalagarh	Outage of Abdullapur-Bawana	Outage of Bawana-Hisar	Outage of Nalagarh-Kaithal	Outage of Nalagarh-Patiala
Power shift in MW →					362	488	50	399	233	648
	From	To	CKT							
400	NATHPA4	ABDULPR4	1	362	-1.00	0.18	-0.12	-0.04	0.22	0.27
400	NATHPA4	ABDULPR4	2	362	0.57	0.18	-0.12	-0.04	0.22	0.27
400	NATHPA4	NALAGRH4	1	488	0.21	-1.00	0.12	0.04	-0.22	-0.27
400	NATHPA4	NALAGRH4	2	481	0.21	0.64	0.12	0.04	-0.22	-0.27
400	ABDULPR4	BAWANA4	1	50	-0.13	0.11	-1.00	-0.09	0.09	0.21
400	BAWANA4	HISAR4	1	399	-0.07	0.06	-0.12	-1.00	0.08	0.08
400	BAWANA4	BHADRG4	1	533	-0.07	0.06	-0.17	0.39	0.11	0.06
400	NALAGRH4	KAITHAL4	1	233	0.17	-0.15	0.06	0.04	-1.00	0.46
400	NALAGRH4	PATIALA4	1	648	0.25	-0.21	0.17	0.05	0.56	-1.00

1.4 Total Transfer Capability

There are terms associated with transfer capability documented in literature. Few of these are as below:

- **Total Transfer Capability (TTC)**
- **First Contingency Incremental Transfer Capability (FCITC)**
- **First Contingency Total Transfer Capability (FCTTC)**

North American Electric Reliability Corporation (NERC) released three documents on the above concepts. One was in May 1995, second in June 1996 and the third in June 1999 [2,3,4]. The definitions of the above terms adapted from the above documents are quoted below:

'***TTC*** *is the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner based on all of the following conditions:*

1. *For the existing or planned system configuration, and with normal (pre-contingency) operating procedures in effect, all facility loadings are within normal ratings and all voltages are within normal limits.*
2. *The electric systems are capable of absorbing the dynamic power swings, and remaining stable, following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit.*

3. *After the dynamic power swings subside following a disturbance that results in the loss of any single electric system element as described in 2 above, and after the operation of any automatic operating systems, but before any post-contingency operator-initiated system adjustments are implemented, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.*
4. *With reference to condition 1 above, in the case where pre-contingency facility loadings reach normal thermal ratings at a transfer level below that at which any first contingency transfer limits are reached, the transfer capability is defined as that transfer level at which such normal ratings are reached.*
5. *In some cases, individual system, power pool, subregional, or Regional planning criteria or guides may require consideration of specified multiple contingencies, such as the outage of transmission circuits using common towers or rights-of-way, in the determination of transfer capability limits. If the resulting transfer limits for these multiple contingencies are more restrictive than the single contingency considerations described above, the more restrictive reliability criteria or guides must be observed.'*

"***First Contingency Incremental Transfer Capability** is the amount of electric power incremental above the normal base power transfers that can be transferred over the interconnected system in a reliable manner based on the conditions 1, 2 and 3 above.*"

"***First Contingency Total Transfer Capability** is the total amount of electric power (net of normal base power transfers plus first contingency incremental transfers) that can be transferred between two areas of the interconnected transmission system based on conditions 1, 2 and 3 above.*"

FCTTC = FCITC + Base Power Transfers

The 1996 NERC document [3] **clubbed TTC, FCITC and FCTTC and now it is referred as Total Transfer Capability only.** It is suggested that the above terms may be suitably defined in the Indian Electricity Grid Code by CERC.

1.5 Simultaneous Transfer Capability

Transfer capability is directional in nature. Each control area could estimate its import and export capability by modeling its own system in isolation. But as far as the integrated system is concerned this would be misleading because the component of network loading attributable to transactions between other control areas has been ignored. Further transfer capability is also heavily affected by the amount and firmness of the transaction between the control areas. Even the firm transactions may have deviations in real time that would have to be accounted for during studies. This is where the operating philosophy adopted in a grid influences the availability of transfer capability in the network.

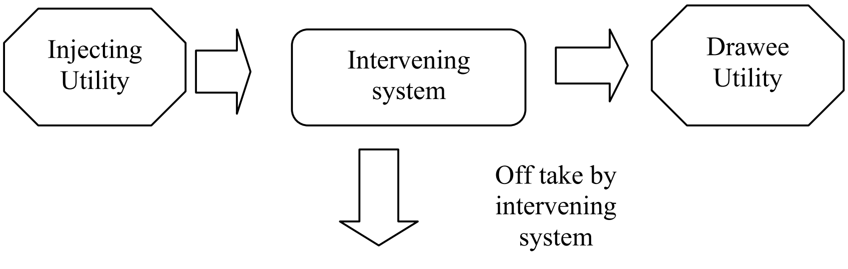


Figure 1: wheeling of power through intervening system

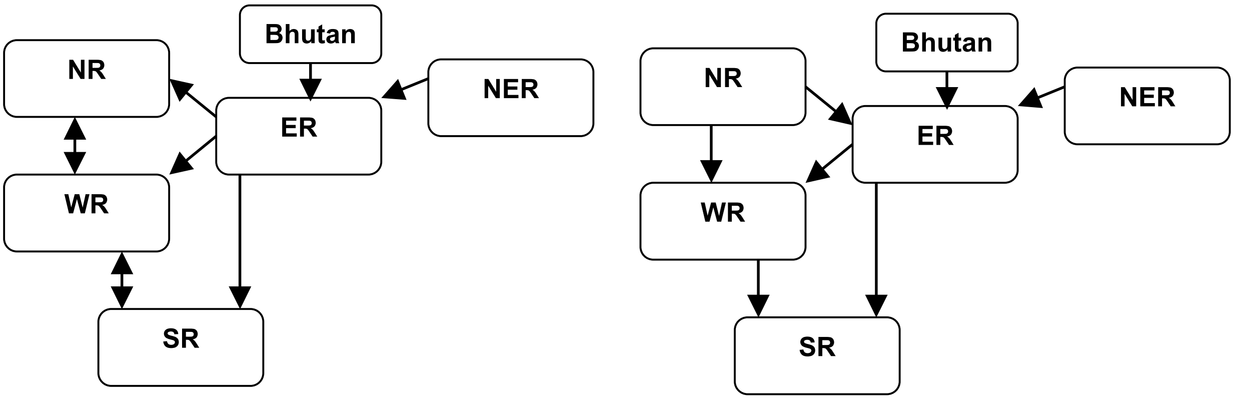
For instance if we consider State A wheeling a huge quantum of power through the Inter State Transmission System (ISTS) passing through its geographical area. The state draws power from this ISTS as per its shares in Central Sector projects. Now if the state's off-take from this ISTS varies considerably from the schedule (either high or low), it will have a great impact on the power transfer through the ISTS. This could be as much as 500-1000 MW and affect the TTC calculations depending on the load assumed in these studies.

Literature explains the above phenomenon through the terms “simultaneous” and “non-simultaneous” transfer capability. These terms as defined in the 1995 NERC document are stated below:

“***Non-simultaneous Transfer Capability*** *is the amount of electric power that can be reliably transferred between two areas of the interconnected electric system when other* <u>*concurrent*</u> *normal base power* <u>*transfers are held constant*</u>.” “***Simultaneous Transfer Capability*** *is the amount of electric power that can be reliably transferred between two or more areas of the interconnected electric system as a function of one or more other power transfers concurrently in effect*.”

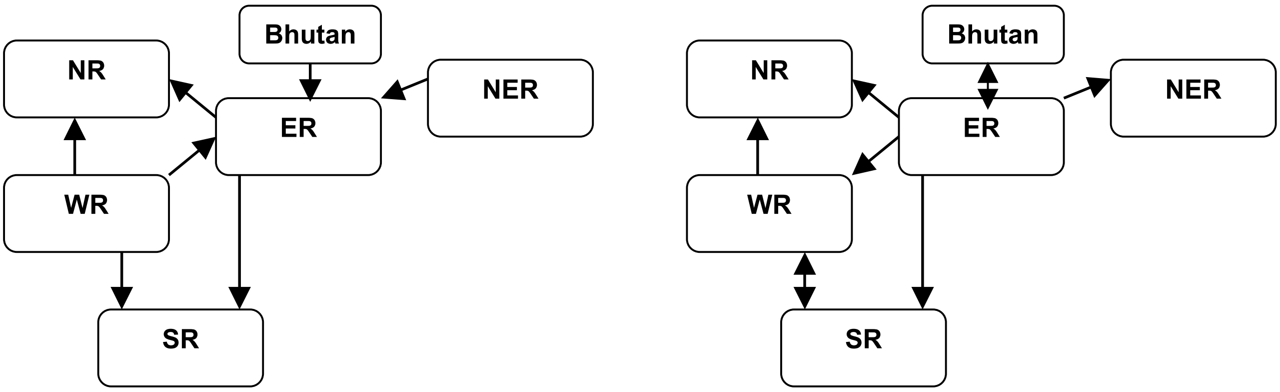
For instance in a three area system, the transfer capability from area A to Area C may be 4000 MW and the transfer capability from Area B to Area C may be 2000 MW independently. But the combined transfer capability from Area A and Area B to Area C would not necessarily be 6000 MW. Relevance of simultaneous transfer capability in the context of NEW grid could further be understood through the schematic diagram of the five regional grids in India. The direction and quantum of power flow during each scenario would vary in different scenarios. For instance the injection in Eastern Region from Bhutan and NER would be high during monsoon and would be reduce to minimum during winter. As a result the network loading in Eastern Region during these months would be different in different conditions. It would be seen that the network loading and the constraints in each of these case would be different. Therefore to arrive at realistic results one has to consider the entire synchronous system in its entirety and simulate all possible future scenarios and transactions along with their duration and intensity.

Figure 2: Different possible scenarios and transactions.



Scenario-1: Normal Monsoon

Scenario-2: Low Load in NR



Scenario-3: Low Load in WR

Scenario-4: Peak winter

1.6 Assessment of Total Transfer Capability

The distinctive features of the electricity system is its inherent dynamic effects and its interplay with the natural and human influences, which must be considered at all times even though they are difficult to fully anticipate.

"*The transmission system's load and its capacity to handle load are in constant flux. Electricity product does not check the map to determine the shortest route...Electric power flows through the grid as dictated by the impedances of the transmission lines and locations where electric power is injected by the generators and consumed by the loads"* [1].

The technical challenges of computing transfer capability in electric power systems have been paraphrased in the paper by Peter W. Sauer [5]. It also quotes from the 1996 document by NERC and says, "*calculations must*

- ☐ *give a reasonable and dependable indication of transfer capabilities*
- ☐ *recognize time variant conditions, simultaneous transfer, and parallel flows.*
- ☐ *recognize the dependence on points of injection/extraction*
- ☐ *reflect regional coordination to include the interconnected network*
- ☐ *accommodate reasonable uncertainties in system conditions and provide flexibility*"

Due to the complexity involved, the assessment of transfer capability from one area to another in an interconnected system is carried out with the help of computer simulation studies. The paper by Peter W. Sauer [5] also suggests the possible steps for computation. They have been listed below:

1. Definition of a base case with the likely scenario during the time frame for which transfer capability is sought
2. Specification of contingencies: The number of contingencies to be considered could vary from a very small number to thousands and their nature could vary from single outage to complex fault switching scenarios.
3. Determination of the network response (through computer simulations) in the base case with normal limits enforced plus all contingencies with emergency limits enforced.
4. Finding maximum transfer through a systematic procedure to increase the specified transfer till the constraints on line flows, voltage or stability are violated. The concept of "most limiting phenomenon" may be used to reduce the computation time.
5. Interpretation of results
6. Repetition for the steps 1 to 5 above for alternate cases with different likely scenarios
7. Estimate reliability margins to account for uncertainty in model configuration and operating conditions.

Power System Engineering Research Centre (PSERC) has published a report [6] that gives a very exhaustive coverage of the various aspects associated with transfer capability. The steps suggested in this report for transfer capability assessment is on similar lines as detailed above. There are several other papers, which elaborate the computation process.

While carrying out simulations for different conditions it would be seen that the limiting condition on some portions of the transmission network or flow gates can shift among thermal, voltage and stability limits as the network operating conditions change over time. **TTC would be the minimum of Stability Limit, Voltage Limit and Thermal limit**.

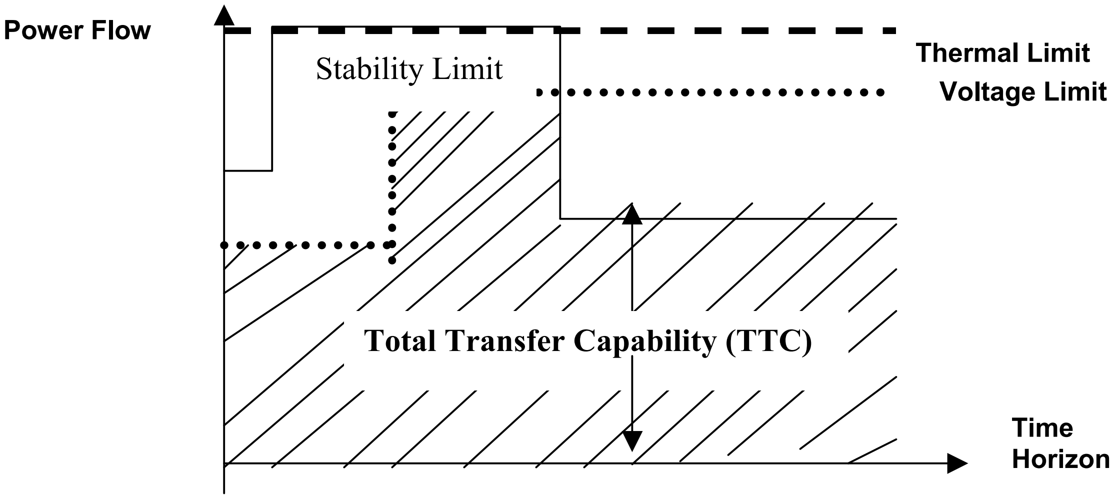


Figure 3: Different power transfer limits

1.7 Simulation method:

Literature available on the computation of Transfer Capability suggests following four methods:

S No.	Method	Description
1	Linear approximation	DC Power Flow Model, Thermal Limit Only
2	Optimal Power Flow (OPF)	AC Power Flow Model, Thermal Limit + Voltage Limit
3	Continuation Power Flow (CPF)	AC Power Flow Model, Thermal Limit + Voltage Limit (Voltage Collapse)
4	Stability constrained	Time Domain Simulations with Dynamic Model

The DC power flow is a gross approximation of the AC power flows as it considers linear models for network topology. It may not be accurate where VAR flow and voltage deviations are considerable. Continuation power flow method considers a series of power system solutions to be solved and tested for limits. The amount of transfer is gradually increased from the base case until a binding limit is encountered. Optimal power flow method requires formulation of an optimization problem with constraints arising from the power flow. The results obtained through OPF may vary depending upon the definition of objective function and the constraints. Stability constrained methods require transient studies to be carried over a case developed with anticipated scenario. Thus it would be seen that above methods may be used depending upon the context and the nature of requirement.

The factors, *inter alia* those are to be considered during simulations are as below:

- **Planning criteria**
- **Operating limits**
- **Network topology**
- **Forecasted load-generation balance**
- **Reliability margins**

The above considerations are discussed in detail in subsequent sections.

Chapter: 2

Consideration for Assessment of Transfer Capability

2.1 Planning Criteria and Its Interpretation

Development of an efficient, co-ordinated and economical system for smooth flow of electricity from generating stations to the load centres and reliable operation in real-time requires meticulous planning in various time horizons viz. long-term, mid-term, short-term and real-time. In India the Central Electricity Authority (CEA), Government of India and the Central Transmission Utility (CTU) in coordination with the State Transmission Utility (STU) are responsible for long term planning (for network expansion) in an integrated manner. Operational planning in the other time horizons and operation in real time is taken care of by the Regional Load Dispatch Centres and the State Load Despatch Centres. The '*Manual on Transmission Planning Criteria*' [7] issued by the CEA is one of the most important reference document for planning and operational purposes.

The planning criteria lists the acceptable performance of the integrated power system following "what if" tests of credible contingencies. As per section 3.5 of the Indian Electricity Grid Code [8], the planning criteria are based on the security philosophy on which the Inter State Transmission System (ISTS) has been planned. It states that as a general rule, the ISTS shall be capable of withstanding and be secured against a selected list of credible contingency outages without necessitating load shedding or rescheduling of generation during steady state Operation. These contingencies shall be considered assuming a pre-contingency system depletion (Planned outage) of another 220 kV D/C line or 400 kV S/C line in another corridor and not emanating from the same substation. All the Generating Units may operate within their reactive capability curves and the network voltage profile shall also be maintained within voltage limits specified. In addition to the above the ISTS is expected to be capable of withstanding the loss of most severe single system infeed without loss of stability and any one of these events defined above shall not cause loss of supply; prolonged operation of the system frequency below and above specified limits, unacceptable high or low voltage; system instability and unacceptable overloading of ISTS elements.

It would be evident from the above that the power system should be capable of successfully handling the listed credible contingencies. However a considerable difference exists between what is a (n-1) contingency in planning horizon and a (n-1) contingency in operating horizon. This aspect therefore needs further elaboration.

In the planning horizon the n-1 contingency implies an element outage

1. Outage of a 132 kV D/C line or,
2. Outage of a 220 kV D/C line or,
3. Outage of a 400 kV S/C line or,
4. Outage of single Interconnecting Transformer, or
5. Outage of one pole of HVDC Bipole line, or
6. Outage of 765 kV S/C line
7. Outage of a single largest infeed

In the real-time an n-1 contingency is usually an event involving simultaneous outage of one or more elements. Few of these case are illustrated below:

i. A tower collapse or 'lightning strike' on a double circuit tower would result in simultaneous loss of two elements.
ii. In case of two main and transfer bus switching scheme, failure of a 400 kV line breaker to open would result in operation of breaker fail protection and loss of multiple elements. Generally, the 'planning criteria' states that not more than two elements should be affected in such cases whereas in actual operation three or more elements are lost.

iii. In a coal-fired station, a fault in the 132 kV system could result in loss of power supply to the Circulating Water (CW) system and tripping of multiple units.
iv. Non-availability or outage or non-operation of bus bar protection at a substation would result in tripping of all the lines emanating from the substation at remote end in Zone-2.
v. A weather disturbance or floods could result in loss of a substation or multiple lines in the same corridor.
vi. In a substation having breaker and a half switching scheme, outage of a combination of breakers could result in tripping of multiple elements for a fault on one line.
vii. Power station auxiliaries such as induced draft fans having sensitive V/f motor controls might trip in case fault on a nearby line is not cleared within zone-1 timings. This would lead to multiple unit outages.

These are just some of the cases, which have been experienced by the operators. There could be many other scenarios not known to the operator. For instance it could be possible that a 6.6 kV or 11 kV auxiliary supply to a HVDC installation is a weak link and could lead to a large contingency any time. Likewise a single bus arrangement temporarily adopted at any power station bus either at 400 kV or 220 kV and below might lead to the outage of the entire power station in case of a bus fault. As the grid size enlarges the operator has to increasingly visualize the possible contingencies and how they would impact the system. This is possible only if all major power stations and substations in the grid report such events leading to a heightened threat perception to RLDC/SLDCs.

A list of such incidents that have actually occurred in the combined North-Central grid (NEW grid) between 26th August 2006 to mid January 2007 is given as Appendix-1. The summary is tabulated below:

Table 3: Multiple Element Contingencies post NEW grid formation up to 15 Jan 07

S No.	**Description**	**Number of instances**
1.	Multiple generating units tripping	**7**
2.	Multiple transmission elements tripping within region	**5**
3.	Tripping of HVDC Pole/ back-to-back inter regional links	**3**
4.	System separation	**2**
5.	Incident of autorestarts/tripping due to fog	**4**
6.	Load crash	**1**
	Total	**22**
	Average per month	**4**

Therefore the system operator has to prepare the system to manage the next credible contingency, which may include more than one element. Professor Dr. Anjan Bose, Professor Emeritus, Washington State University also commented on this issue during his visit to NRLDC on 11th Dec 2006. He said, '***the so-called first contingency withstand capability is very difficult to define in system operation. Best practices in this area are very difficult to find. We have to evolve our own best practices.'***

Besides the difference in the interpretation of n-1 criterion in planning studies and real-time operation a considerable difference also exists between the network topology and scenario assumed in planning studies and those existing physically at a given time frame. This may occur due to the several reasons some of which have been listed below:

1. Forecast errors in spatial distribution of load due to socio political reasons
2. Non-availability of transmission elements or generators envisaged in that timeframe due to disparity in project implementation, mid-course changes, prolonged outages.
3. Reconfiguration of switching arrangement due to practical constraints viz. radial operation, opening of bus couplers, opening of 220 kV loops etc. Increase in fault levels lead to opening of many 220 kV loops during operation.
4. Other socio-economic uncertainties in a progressive economy

These are the major cause for the difference in transfer capability in real time from those anticipated through planning studies.

2.2 Operating Limits

The ability of power system to reliably transfer power may be limited by the physical and electrical characteristics of the systems including any one or more of the following:

- Thermal limits
- Voltage limits
- Stability limits

2.2.1 Thermal Limits

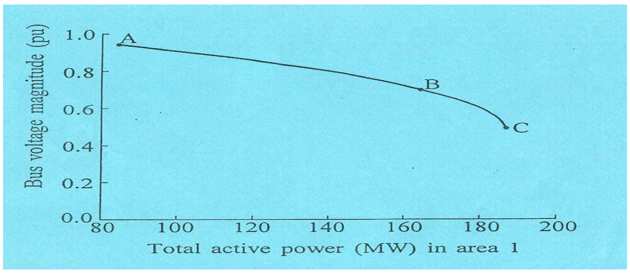
Thermal Limits establish the maximum electrical current that a transmission line or electrical facility can conduct over specified time periods before it sustains permanent damage by overheating or before it violates public safety requirements. The thermal limits for the commonly used conductors in the transmission system as given in the Technical Report number 77 of Central Board for Irrigation and Power [9].

2.2.2 Voltage limits

System voltages and changes in voltage must be maintained within the acceptable range as defined in the Grid Codes. For example, minimum voltage limits can establish the maximum amount of electric power that can be transferred without causing damage to the electric system or customer facilities. A widespread collapse of system voltage can result in a black out of portions or the entire interconnected network. Operating limits for bus voltages as prescribed by the IEGC is tabulated below:

Permissible Operating Voltage

Voltage in kV rms		
Nominal	Maximum	Minimum
400	420	360
220	245	200
132	145	120



Typical PV curve adapted from
Power System Stability and Control

Figure 4: Voltage limits

Unlike frequency, voltage at each node in an integrated power system the may be different depending upon the network topology and availability of reactive support. Further the critical voltage[4] for these nodes may also be different. Thus the proximity of each node to the voltage collapse point may be different. The first node to hit the critical voltage would determine the limiting point.

For instance voltage collapse was observed in part of Punjab system (Northern Region) on 10th June 2007 when its total load crossed 6600 MW compared to the normal load of around 5600 MW. A few generating units also tripped which deteriorated the situation further. Thus voltage collapse is a credible event and must be considered suitably during transfer capability

---

[4] Critical voltage is the voltage at below which the voltage dips even if the reactive support is increased. This may also be understood as the point of voltage collapse. Point “C” in the PV curve shown above.

assessment. The event also prompts that every control areas especially the state utilities must estimate the transfer capability of their system.

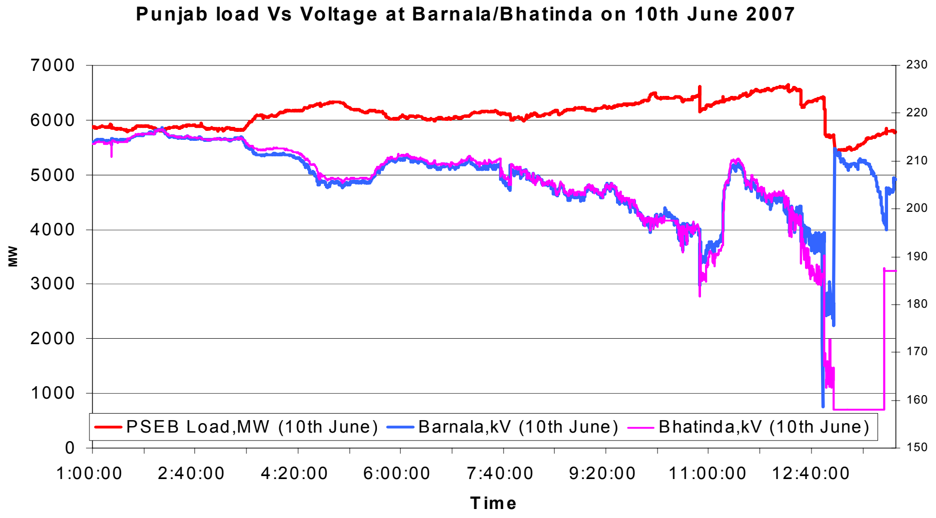


Figure 5: Voltage collapse in the Punjab system

2.2.3 Stability Limits

Prabha Kundur, in 'Power System Stability and Control' [11], defines power system stability as that 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. He adds that the disturbance may be small or large. Small disturbances in the form of load changes take place continually, and the system must be able to operate satisfactorily under these conditions. The system must also be capable of surviving numerous disturbances of a severe nature such as short-circuit on transmission line, loss of a large generator or load, or a loss of a tie between two subsystems.

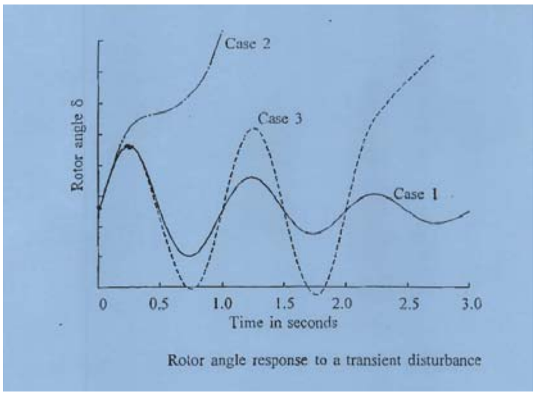


Figure 6: Rotor angle response to a transient disturbance for different types of system

Adapted from Power System Stability and Control by Prabha Kundur

All generators connected to ac interconnected transmission system operate in synchronism[5]. Immediately following a system disturbance, generators begin to oscillate relative to each other,

---

[5] *"The synchronous operation of interconnected synchronous machines is in some way analogous to several cars speeding around a circular tract while joined to each other by elastic links or rubber bands. The cars represent*

causing fluctuations in system frequency, line loadings, and system voltages. For the system to be stable the oscillations must diminish as the electric systems attain a new, stable operating point. If a new, stable point is not quickly established, the generators will likely lose synchronism with one another, and all or a portion of the interconnected system may become unstable. The result of generator instability may damage equipment and cause uncontrolled, widespread interruption of electric supply to customers. The figure above illustrates the behaviour of synchronous machines for stable and unstable situations after a disturbance. Case 1 is a stable case where the rotor angle increases to a maximum and then oscillates with decreasing amplitude until it reaches a steady state. In case 2, the rotor angle continues to increase steadily until synchronism is lost. In case-3 the system is stable in the first swing but becomes unstable as a result of growing oscillations.

Stability depends on both the initial operating state of the system and the severity of the disturbance. Since the occurrence of disturbance is random therefore the system operating point must always be kept far away from the point of instability.

The operating limits would be minimum of thermal, voltage and stability limit.

2.3 Network Topology and Anticipated Load Generation Balance

Transfer capability is dependent on the network topology. The power system must be modeled with all existing as well the elements likely to be available in the time frame for which the transfer capability is being assessed. This requires accurate and timely inputs from the transmission utilities, generating companies and the other constituents in the power system. The elements under scheduled outage are required to be considered suitably. However the uncertainty in the maintenance schedule is a major constraint in the assessment of transfer capability.

2.4 Reliability Margins

The transfer capability determination depends upon a myriad of assumptions. These include projections of system conditions, transmission system topology, projected customer demand and its distribution, generation despatch, location of future generators, future weather conditions, available transmission facilities and existing and future power transactions. Such parameters are assembled to produce a scenario to be used to project transfer capabilities under a reasonable range of transmission contingencies as specified in the transmission planning criteria. Therefore, calculations of future transfer capabilities must consider the inherent uncertainties in projecting such system parameters over longer time periods. Margins in the form of **Transmission Reliability Margin** (TRM) and **Capacity Benefit Margin** (CBM) must be kept aside to provide operating flexibility in real time. These margins are necessary for reliable transmission services to all transmission system users under a broad range of potential system conditions.

The various issues related to reliability margins are discussed subsequent sections.

---

synchronous machines and the rubber bands are analogous to transmission lines. When all cars run side by side, the rubber band remains intact. If force applied to one of the cars causes it to speed up temporarily, the rubber bands connecting it to the other cars will stretch; this tends to slow down the faster car and speed up the other cars. If the pull on one of the rubber bands exceeds its strength, it will break and one or more cars will pull away from the other cars." Prabha Kundur

Chapter-3

Reliability Margins

3.1 Reliability of Power System

Steven Stoft in Power System Economics [12] says, "*Power markets are the only markets that can suffer a catastrophic instability that develops in less than a second...The extent and speed of the required coordination are unparalleled*." Thus market mechanisms for bringing economy and efficiency in any power system can take place only if the power system is secure and healthy. Thus an understanding of the aspects related to power system reliability is essential in the context of open access as well.

As per the CIGRE Reports on Power System Reliability Analysis (1987, 1992)[6], reliability is a general term encompassing all the measures of the ability of the system generally given as numerical indices to deliver electricity to all points of utilization within acceptable standards and in the amounts desired. It comprises of "adequacy" and "security". Adequacy (generation or transmission) is the capability of the power system to supply the load in all the steady states in which the power system exists considering standard conditions while security is the ability of power system to withstand sudden disturbances.

Dr. Mohammad Shahideopour in his IEEE tutorial [13] says, "*Reliability is the performance level of the elements of the bulk electric systems that results in electricity being delivered to the customers within accepted standards and in amount desired. It is expressed in terms of the frequency, duration and magnitude of adverse effects on electric supply...Reliability comprises of Adequacy and Security…Adequacy is reliability within the range of events which can be controlled by operators whereas Security is reliability under conditions beyond the control of operators*."

In general terms ensuring reliability of any system requires an understanding of risk management that has two components- **likelihood** that something will happen and the **consequences** if it does. The NERC document titled, 'Reliability Criteria and Operating Limits Concepts' [14], says, "*In the context of electric system reliability, risk is the likelihood that an operating event will reduce the reliability of the interconnection and the consequences that are unacceptable. Because we cannot prevent events from happening, we plan and operate the electric system so when they do, their effects are manageable, and the consequences are acceptable. So one of the keys to providing a reliable interconnection is managing risks*."

Table 4: Risk Management: Likelihood and consequences

Consequences	Unlikely events with unacceptable consequences	Likely events with unacceptable consequences
	Unlikely events with acceptable consequences	Likely events with acceptable consequences

Risk

Likelihood

"Adapted from Reliability Criteria and Limits Concepts", NERC, May 2007

---

[6] Power System Reliability Analysis-Application Guide, Paris, 1987
Power System Reliability analysis- Composite Power System Reliability Evaluation, Paris, 1992

Therefore while discussing about the reliability of the Indian bulk power supply system one needs to look into its characteristics and the operating philosophy. The Indian Electricity Grid Code (IEGC) lays down the rules, guidelines and standards to be followed by the various agencies and participants in the system to plan, develop, maintain and operate the power system, in the most efficient, reliable, economic and secure manner, while facilitating healthy competition in the generation and supply of electricity. Some of the provisions of the IEGC distinguish the Indian grids from the grids in rest of the world. Moreover the socio-technical, economic and political aspects also bring in certain peculiarities in the Indian grids that must be accounted for during the assessment of transfer capability and determination of reliability margins.

3.2 Distinguishing Features of the Indian Grid

Indian bulk power supply system is progressive and evolving. It has several features that distinguish it from the other system in the world. Few of those unique features have been listed below:

1. Haulage of power over long distances
2. Resource inadequacy leading to high uncertainty in adhering to maintenance schedules
3. Pressure to meet demand even in the face of acute shortages and freedom to deviate from the drawal schedules.
4. A statutorily permitted floating frequency band of 49.0 to 50.5 Hz
5. Non-enforcement of mandated primary response, absence of secondary response by design and inadequate tertiary response.
6. Limited market mechanisms to complement reliability and absence of an explicit ancillary services market
7. Inadequate safety net and defense mechanism

All the above features have a bearing on grid operation as well as on the assessment of transfer capability as explained ahead.

3.2.1 Haulage of Power Over Long Distances

India is a large country with huge disparity in the availability of generating fuel resources Generation from large generating complexes has to be transmitted over hundreds of kilometres to the load centres. Extra high voltage and high capacity transmission corridors[7] are being constructed to cater to the present as well as future load growth. Operation of long EHV transmission lines in a system is a special challenge especially during skewed load dispatch scenarios. The situation becomes even more difficult due to the disparity in the implementation of the envisaged development projects[8].

Indian electricity grids have a combination of ISTS lines operating in parallel with the state sector lines both at 400 kV and 220 kV level. HVDC Bipole also operates in parallel with the AC transmission system. For the ISTS, CERC has specified a network availability of 95% for HVDC system and 98% for the AC system. For the State sector, no such availability norm exists even today. The combined availability of the state and the Central transmission system is what affects the transfer capability.

If we consider a system of five parallel elements having an annual availability of 95%, 95%, 98%, 99% and, 98% each then the probability that all the five elements will be available simultaneously at any point of time is = 0.95 x 0.95 x 0.98 x 0.99 x 0.98 =0.86 or 86 %. Thus

---

[7] Right of Way (RoW) problems are also have to be considered

[8] Generation projects, Transmission projects, Interconnecting transformers, Implementation of SCADA & communication system

once in seven days one could expect one element out. This would affect the reliability as well as the transfer capability of the system.

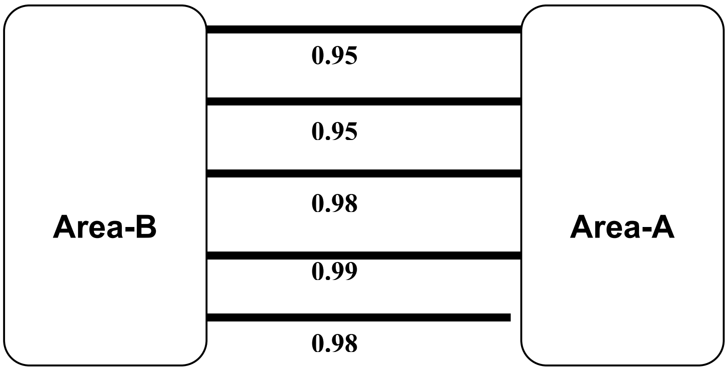


Figure 7: Reliability diagram of transmission lines.

Roy Billinton and Ronald N. Allan have dealt with the issues related to power system reliability in their book titled, "Reliability Evaluation of Power Systems' [15]. They say,

"System behaviour is stochastic in nature, and therefore it is logical to consider that the assessment of such systems should be based on techniques that respond to this behaviour (i.e. probabilistic techniques)...
"Failures of components, plants and systems occur randomly; the frequency duration, and impact of failures vary from one year to the next..."
"The assumption can be made that failures which occur randomly in the past will also occur randomly in future."

With the above in background a statistical calculation was made to examine the performance of one of the trunk corridor (and usually heavily loaded) in the Indian grid viz. the Central to West corridor of Northern Region. This corridor has several parallel EHV lines. The major ones are listed below:

1 HVDC Rihand-Dadri Pole-I
2 HVDC Rihand-Dadri Pole-II
3 400 kV Kanpur-Agra
4 400 kV Kanpur-Ballabgarh
5 400 kV Allahabad-Mainpuri-Ballabgarh-I
6 400 kV Allahabad-Mainpuri-Ballabgarh-II
7 400 kV Lucknow-Moradabad
8 400 kV Panki-Muradnagar
9 400 kV Unnao-Agra
10 400 kV Unnao-Bareilly-I
11 400 kV Unnao-Bareilly-II
12 220 kV Kanpur/Panki-Mainpuri D/C

If one goes by the target availability norms as per CERC (95% for HVDC and 98% for AC lines) one would see that the probability of simultaneous availability of the above lines would be 0.72. The actual outage hours of the above lines during 2005-06 were 1810 hrs. i.e. 21% of the time. Alternatively the actual probability of the simultaneous availability of was found to be 0.79. This implies one could expect a constraint in the above corridor one in five days. The transfer capability of the system would be affected during all such constraints. This discussion also leads us to the issues of line dependability.

For instance if the system operator observes that a particular line has autoreclosed on a single phase to ground fault several times within a span of two hours, he would have to assume that the line could go out any time and take action accordingly to make the system secure. This aspect could be understood from following diagram which displays the number of autorestarts, line trippings and the transmission corridors affected in Northern region on 23rd Dec 06, 27th Dec 06, 31st Dec 06 and 01st Jan 07 due to winter fog.

Impact of winter fog 2006-2007

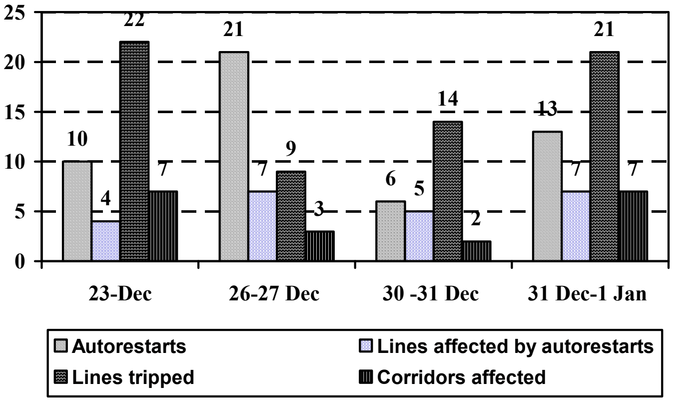


Figure 8: Impact on transmission network due to fog.

3.2.2 Resource inadequacy and uncertainty in adhering to maintenance schedules

The uncertainty in adhering to maintenance plans creates an uncertainty in the network topology to be considered for simulations required for assessment of transfer capability. This has a bearing on the power flows and actual interchanges during the real-time.

3.2.3 Pressure to meet demand and freedom to deviate from schedule

The demand for electricity in India is growing by leaps and bounds. However in the absence of matching addition in the generation capacity and a freedom to deviate from the interchange schedule utilities have a tendency to consider Unscheduled Interchange (UI) as an infinite source. This has serious implications on the frequency profile[9] as well as the transmission facility loading. Unscheduled Interchange (UI) also has an implication during the assessment of Total Transfer Capability (TTC). Strictly speaking, the TTC calculations should be based on the control area's own generation plus committed long-term purchases plus short-term purchases within the region (for which no transmission constraint is perceived). All the open access transactions should be superimposed over this base case to work out the TTC. However, if the actual load met in the past were taken in the base case, the UI quantum would change the base line flows considerably and give a different TTC.

3.2.4 Statutorily permitted floating frequency band of 49.0 Hz to 50.5 Hz and inadequacy in primary, secondary and tertiary response

Large synchronous interconnections have large system inertia constants[10]. For instance in the NEW grid with 1 Hz drop in frequency implies a generation loss of around 1800 MW that may result in a sharp change in transmission line loadings and voltage (both of which are potentially

---

[9] Low frequency sometimes causes over-flux alarm/trippings of the 400/220 kV ICTs in many pockets of the grid. This has the potential to initiate a larger system disturbance.

[10] Quantum of power required to change the system frequency by 0.1 Hz

harmful). Further in the absence of primary response[11] and secondary control and limited tertiary response (in most cases load shedding by the state utilities could take half an hour or even more)

For instance in the NEW grid, a 900 MW load reconnection, say in Northern Region, without a corresponding increase in generation would result in the frequency fall by 0.5 Hz (with a power number of 1800 MW/Hz for the combined grid of 60,000 MW). If the NR system size before the load reconnection was 25000 MW, then with a load frequency response of 3% per Hz, the NR load would increase by [900-(25000 x 0.03 x 0.5) = 511 MW] say 500 MW. This would translate to an increase in the import by NR by 500 MW. Voltages in the 400 kV system of NR would also fall by 5-6 kV at the 400 kV level (1% change in frequency causing a 1% change in voltage plus the additional reactive drop in the lines). This could continue for at least half an hour making the system extremely vulnerable and insecure during this period. In case secondary response is available, the affected control areas would take action within five minutes and quickly bring the system to a secure state.

Such instances of load disconnection/reconnection are very common, particularly at the hour boundaries due to planned load restrictions on agricultural consumers. This phenomenon does not exist in any of the other power systems worldwide as they all operate with adequate reserves, tight frequency control and effective primary, secondary and tertiary response.

3.2.5 No explicit ancillary services market

The frequency linked Unscheduled Interchange (UI) mechanism complements reliability and addresses the frequency stability of the Indian grids. This mechanism however does not recognize that the UI involves three components. (i) Energy component (ii) Frequency component and (iii) line loading component.[12] This has become very important with the formation of the NEW grid and the need to shift from frequency-linked dispatch of plants to a security constrained dispatch. The UI rates need to incorporate the line loading component to act as a congestion management tool.

The ancillary services are the services necessary to support the transmission of electric power from seller to purchaser and to maintain reliable operations of the interconnected transmission system. These include energy imbalance, voltage control, frequency regulation, load following, spinning reserves and system blackstart. IEGC has provisions for making these services available to the system. However due to resource inadequacy and in the absence of explicit market mechanisms (except in case of energy imbalance in the form of UI) the procurement of these services are mainly through administrative means or regulatory orders.

3.2.6 Inadequate safety net and defense mechanism

System planners manage risk through well-established protection system designs that reduces the chance that likely events will jeopardize the reliability of the transmission system. Substation circuit breaker configurations are designed to isolate (contain) transmission equipment failure so that they result into cascade failures. Likewise under frequency relays are provided in the system to automatically disconnect a particular load feeder in case the system goes below a certain threshold. However the experience in the Indian grid suggests that the reliability of the defense mechanisms itself needs to be improved many times over.

---

[11] Primary response by generators is essential for frequency stability

[12] **North American Electric Reliability Corporation**, ‘Joint Inadvertent Interchange Task Force (JIITF) White Paper: Recommendations for the Wholesale Electric Industry of North America: Inadvertent Interchange, Draft 5d’, May 10, 2002

The distinguishing features of the Indian grid as discussed above amply suggest need for evolution of operating criteria similar to the planning criteria existing for planning purposes.

3.3 Need for Reliability Margin and its Legitimacy

Reliability of the synchronous interconnection is a function of the reliability of its various subsystems. Utilities could always invest in better and higher quality systems to reduce failures. However everything in this world is finite and 100 % reliability is an utopia. Therefore reliability margins have to be maintained in the system at all times to enhance the chances of survival in case of potentially harmful events. It is evident from the discussion in the previous sections that reliable transmission services to all transmission system users under a broad range of potential system conditions would require adequate margins in the system at all times. Reliability margin helps in ensuring the security of the grid in dynamic changes taking place in real time and provides cushion to grid operators to respond to events happening in the grid in real time. Hence it is absolutely essential and non negotiable. Since transmission service is an indivisible shared facility (public service), these margins are available for use by all the transmission users in real time. "*The beneficiary of this margin is the "larger community" with no single, identifiable group of users as the beneficiary. The benefits of reliability margin extend over a large geographical area. They are the result of uncertainties that cannot reasonably be mitigated unilaterally by a single Regional entity*." [3].

Besides the above there is one more perspective, which justifies the need for reliability margin. The transfer capability determination depends upon a myriad of assumptions. These include projections of system conditions, transmission system topology, projected customer demand and its distribution, generation despatch, location of future generators, future weather conditions, available transmission facilities and existing and future power transactions. Such parameters are assembled to produce a scenario to be used to project transfer capabilities under a reasonable range of transmission contingencies as specified in the transmission planning criteria. Therefore, calculations of future transfer capabilities must consider the inherent uncertainties in projecting such system parameters over longer time periods.

The legitimacy of reliability margins is also established worldwide and well documented in literature.

Roy Billinton and Ronald Allan say "*The time to perform a remedial action is a fundamental parameter in determining whether a state is adequate and secure, adequate and insecure, inadequate and secure, inadequate and secure, or inadequate and insecure. Any state which can be defined as either inadequate or insecure is clearly a system failure state and contributes to system unreliability".* [15]

Charles Concordia [16], says, "*ties have been said to have two kinds of functions, the economic interchange of energy and the sharing of generation reserve. If a tie is installed to allow an economic interchange of energy, then it can only be counted upon for reserve support if it has enough margin of capacity at its maximum normal load to withstand a sudden further increase of power flow equal to at least the capacity of, for example, the largest generating unit of the receiving system. Thus, it is the dependable pick-up capacity, rather than the total capacity, that is significant. On the other hand, if the import is so great that loss of a generator causes the tie lines to trip, then even more generation is lost, so the situation is made worse. That is, a tie will make things either better or worse; it cannot remain neutral."*

Section 3.5 (b) of the IEGC quotes from the CEA's Manual on Transmission Planning Criteria which says," The ISTS shall be capable of withstanding the loss of most severe single system infeed without loss of stability." It further says that the event should not cause unacceptable overloading of ISTS elements.

3.4 Consequences of Not Providing for a Reliability Margin in Indian context

The likely consequences of scheduling the interregional links without any margin would be as under:

i. There would be frequent curtailments in real time, due to network outages, which would affect all the RLDCs/SLDCs in the country if the transaction involves multiple regions (crossing several seams). The effect on a single transaction due to curtailment could be as low as 2 MW and the system operators would be busy in rescheduling and catering to this ‘private’ need of stakeholders at a time when the larger ‘public’ issue of grid security is at stake. It also has the potential for creating commercial disputes arising from rounding off errors and difference in implementation time due to communication failure etc.

ii. Power shortages and compulsion to meet demand by most of the state utilities would result in more load being connected in the Northern and Western grid. This would lead to a drop in frequency, as there would not be commensurate increase in generation in Eastern region. The line loadings would also increase above the TTC levels and make the system insecure to even one element outage. A 1 Hz change in frequency could result in inter regional line loading changes of the order of 1000 MW as explained earlier.

iii. Even if all state utilities were to give an undertaking that they would honour the inter regional schedule and maintain their drawals accordingly, such an undertaking would not be sustainable. Tight control at the interregional level (no UI) would be completely inconsistent with loose control at the inter state level (no limit on UI with UI going upto 30-40% of schedules for large states and a floating frequency regime).

iv. The RLDCs would have to perpetually persuade, cajole and direct the SLDCs to reduce drawal (even at 50 Hz in case of a skewed dispatch scenario) so as to reduce the line loadings. The SLDCs which unfortunately even today still act as an extended arm of the retail supplier do not have adequate appreciation of network security and instead argue as to why they should shed load at 50 Hz. SLDCs have to realize that the last 200-300 MW would be the proverbial last straw on the camel’s back and could result in a grid collapse affecting the country and the credibility of the entire Electricity Supply Industry (ESI) at such a crucial juncture.

Reliability margin is said to have two components Transmission Reliability Margin **(TRM) and** Capacity Benefit Margin **(CBM). These are explained ahead.**

3.4.1 Transmission Reliability Margin (TRM)

NERC documents define TRM as the amount of transmission transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and its associated effects on ATC calculations, and the need for operating flexibility to ensure reliable system operation as system conditions change.

European Transmission System Operators (ETSO) define TRM[13] as “*a security margin that copes with uncertainties on the computed TTC values arising from:*

1. *Unintended deviations of physical flows during operation due to physical functioning of load frequency regulation*
2. *Emergency exchanges between TSOs to cope with unexpected unbalanced situations in real-time*

---

[13] “Definitions of Transfer Capacities in Liberalised Electricity Markets”, Final Report April 2001

3. *Inaccuracies e.g. in data collection and measurements".*

All transmission system users benefit from the preservation of TRM by transmission providers. It is the "uncommitted" transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. It provides a reserve of transfer capability that ensures the reliability of the interconnected transmission network. The actual system conditions may change considerably in short periods of time due to operating conditions and therefore cannot be projected without the provision of a transfer capability margin. TRM is thus time dependent and generally a larger amount is necessary for longer time horizons.

3.4.2 Capacity Benefit Margin (CBM)

As per the 1996 NERC document, **Capacity Benefit Margin (CBM)** is defined as that amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

Reservation of CBM by a load serving entity allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The CBM is a more locally applied margin than TRM, which is more of a network margin.

As of now there is no compulsion on utilities in India for maintaining a spinning reserve. The National Electricity Policy (Section 5.2.3) states *'In order to fully meet both energy and peak demand by 2012, there is a need to create adequate reserve capacity margin. In addition to enhancing the overall availability of installed capacity to 85%, a spinning reserve of at least 5%, at national level, would need to be created to ensure grid security and quality and reliability of power supply.'*

It is expected that after the implementation of the above provisions, control areas would be maintaining a spinning reserve either within its own system or outside. In the latter case, they would need to reserve some capacity on the inter state lines for such spinning reserve which becomes a committed long-term use of the transmission system viz. CBM.

In the present context, no spinning reserve exists. However control areas have the freedom to overdraw. Further, in case of tripping of any unit in one Region either in the state or Central sector, the power system should be able to support the system in distress at least till operator action is taken. In the Indian context, CBM would take into account the non-simultaneous and simultaneous overdrawal/ under drawal by the state constituents resulting from demand forecast error or the sudden outage of the largest size generating unit in a control area. In real time operation, the TRM and the CBM would actually be used up wholly or partly by utilities in the grid. However, the system operator must always ensure that the system is secure all the time for withstanding the next contingency.

3.4.3 Quantum of Reliability Margin

Transmission Reliability Margin (TRM): As already discussed TRM is required because the assumptions taken in the base case may or may not be true in actual operating conditions. For instance we may have assumed that all lines are in but in actual operation, a 400 kV line is on planned maintenance. Likewise, a load center based generation may be out resulting in TTC reduction. TRM is therefore kept to take care of these uncertainties. There could be several methods to work out TRM. Following methods have been elaborated in reference [5] and [6].

TRM = TTC in the base case – TTC in the worst scenario
OR
TRM = TTC with normal line ratings – TTC with line ratings lowered by 2 % from normal
OR

TRM could also be calculated from probabilistic methods

Capacity Benefit Margin is more from the viewpoint of generation reliability. In the US context, the transmission utilities were vertically integrated utilities serving some native load in its own area. These entities could keep a spinning reserve anywhere in the system. However to call on this spinning reserve, there had to be spare capacity available on the transmission system and these transmission utilities kept a CBM on their network for their own use. Mapping the same to the Indian conditions, each RLDC's footprint extends over its region. It must ensure that even if a large sized unit trips within its system (it could be the single largest infeed as well), there is adequate spare capability on the transmission system. Currently, the largest sized unit is 500 MW. However very soon 660 MW and 1000 MW units would also be commissioned in the Indian grids. These would give one figure for CBM. Alternatively, we have loose power pools and there is a flexibility to deviate from the schedules. Assuming a 2% forecast error by utilities, we could estimate the CBM as 2 % of the size of the regional grid.

Thus the quantum of reliability margins would depend on the characteristics of the power system and its operating philosophy. The margins would be lower in system in power systems having robust transmission system, reliable protection systems and adequate safety net. The margins would also be lower when the planned maintenance schedules are firm and load – generation can be forecasted with substantial accuracy. A rigorous calculation of reliability margin in the Indian context would give out figures much higher than presently being considered by different RLDCs in India.

Chapter-4

Methodology for Assessment of Transfer Capability

4.1 Input Data for Assessment of Total Transfer Capability

The European Transmission System Operators (ETSO) define TTC as “the maximum exchange programme between two area compatible with operational security standards applicable at each system if future network conditions, generation and load patterns were perfectly known in advance.” Further they state that TTC is always related to a given power system scenario i.e. generation schedule, consumption pattern and available network that constitute the data allowing to build up a mathematical model of the power system (load flow equations). The input data required for these studies in India may be assimilated through the following sources.

S No.	Input Data	Suggested Source
1.	Planning Criteria	As per the latest Transmission Planning Criteria issued by Central Electricity Authority (CEA)
2.	Network Topology	The existing network with full elements available to be considered with the exception of the elements that shall be out for the entire assessment period. The new transmission elements expected to be available during the assessment period to be considered
3.	Transmission line limits[14] (Thermal, Stability, Voltage)	Thermal limits for different conductors as per the CBIP technical report No. 77, May 1991. Stability limit for individual transmission line is to be as per the line loadability limits in multiples of Surge Impedance Loading versus line length curve (St. Clair curve) indicated in CEA Planning criteria duly discounted for the compensation devices series as well as shunt. Voltage limits as mentioned in CEA planning criteria
4.	Unit availability	The maintenance schedule as available in the Regional Load Generation Balance Report (LGBR) finalized by Regional Power Committee. The new generating units expected to be available during the assessment period to be considered.
5.	Coal fired thermal despatch	The ex-bus generation of the thermal generating units arrived after deducting a normative auxiliary consumption from the installed capacity. The generation output could be further discounted by the performance index of generating units of a particular size as compiled by CEA. The despatch could be same for the off peak as well as peak hours.
6.	Gas based thermal despatch	Past trend of Plant Load Factor as compiled by CEA
7.	Hydro despatch	Hydro despatch for peak and off peak hours could be based on the past actual data available at RLDC/SLDC. Choose the day corresponding to the median consumption of same month last year. The current inflow pattern to be duly accounted
8.	Loads	Load could be weighted average of loads from two sources. One- the load met on the day in the same month last year, having median consumption/day and second- the forecasted load as per LGBR. These figures could then be scaled depending on the total generation availability arrived from the thermal and hydro despatch. Imports from the neighbouring regions to be neglected initially.

Accuracy and timely availability of the above input data is essential for reliable estimates of TTC. Still the transfer capability observed during real time may sometimes be different from the

---

[14] Simulation models generally have a provision to fill the operating limits for transmission facilities. The operating limit may be taken as minimum of thermal limit and the line loadability permitted by St. Clair curve. Appendix-2 and Appendix-3 may be referred.

values estimated through off line studies. This is generally attributed to forecast errors and the variance in the assumed conditions and actual conditions.

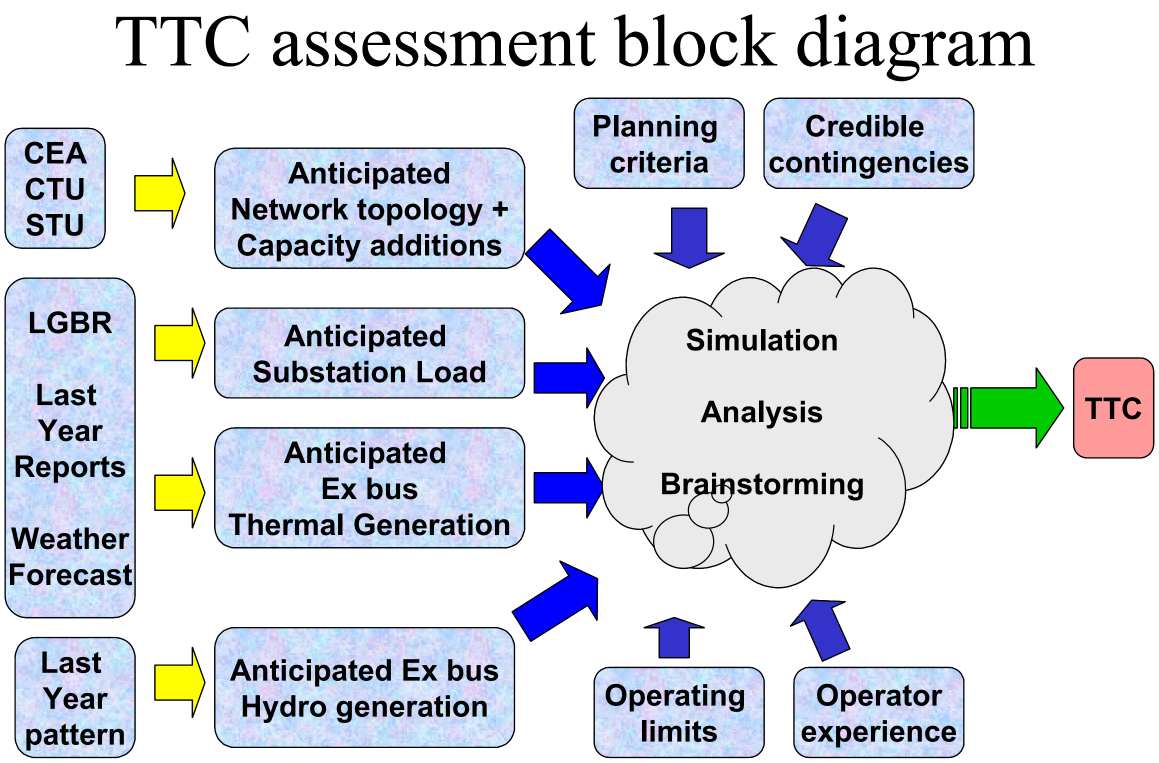


Figure 9: TTC assessment block diagram.

4.2 Time frame for Assessment of Transfer Capability

As per the CERC regulations for Short-term Open Access (STOA), the STOA customer can seek reservation on transmission corridor up to three months in advance. The TTC calculations therefore would have to be done for at least three months in advance. In case of major deviation from the anticipated network topology and load generation balance and the TTC computed earlier would have to be revised.

Since TTC is time variant there could be different figures for different time of the day. Initially TTC could be computed for four cardinal points of the daily load curve viz. night off peak, morning peak, afternoon trough and evening peak. Later on this could be done on an hourly basis as well.

4.3 Computation of Scheduling and Operating Limits

Literature recommends that the transfer capability available after deduction of reliability margin could be offered for commercial use. For secure operation of the grid, the simultaneous interchange of a particular area should be within **TTC – Reliability Margin**. Bonneville Power Administration refers to this as the **Operating Transfer Capability OTC**[15] while the European Transmission System Operators of Union for Coordination of Transmission of Electricity (UCTE) term this as **Net Transfer Capacity (NTC)[16].** This philosophy is in slight variance with that

---

[15] http://www.transmission.bpa.gov/Business/Customer_Forums_and_Feedback/ATC_Methodology/documents/ATC_Establish_TTC.pdf

[16] http://www.etso-net.org/upload/documents/Transfer%20Capacity%20Definitions.pdf

prescribed by NERC, which talks about transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. This is referred to as the "**Available Transfer Capability** (ATC)".

If one maps the above in the Indian context one could consider the long-term open access transactions as "committed uses". ATC would then be defined as the transfer capability after deducting the reliability margin and long-term open access transaction. However the long-term users of transmission system have the freedom to revise their network usage creating further margins available for use by short-term users (day-ahead & same-day). Thus to avoid confusion and to allow maximum utilization of the transfer capability in the transmission system, the definition of ATC as given by NERC could have to be slightly modified to suit the Indian requirement.

ATC (for LTOA + STOA) = TTC - Reliability Margin

ATC (for STOA) = TTC – Reliability Margin - LTOA

Scheduling/Operating limit for LTOA + STOA = TTC – Reliability Margin

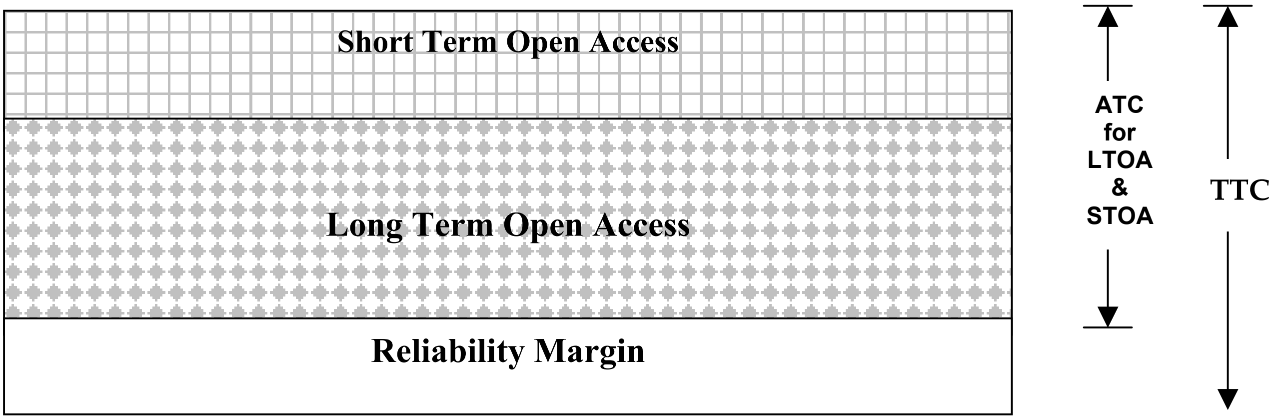


Figure 10: Total Vs. Available Transfer Capability

Rigorously, 720 such hourly values for all the major flowgates could be posted on the web, which is not practical as of now. To begin with peak and off-peak ATC could be determined for the desired period.

Northern Regional Load Despatch Centre has been posting the total import capability of Northern Region (three month ahead) based on computer simulations since September 2006 (after formation of NEW grid) on monthly basis. This is available on the 'Open Access' link on the home page (www.nrldc.org). Further refinements are required in terms of posting the reverse transfer capability incorporating a probabilistic outlook.

Chapter-5

Risks Associated With the Violation of Transfer Capability Limits

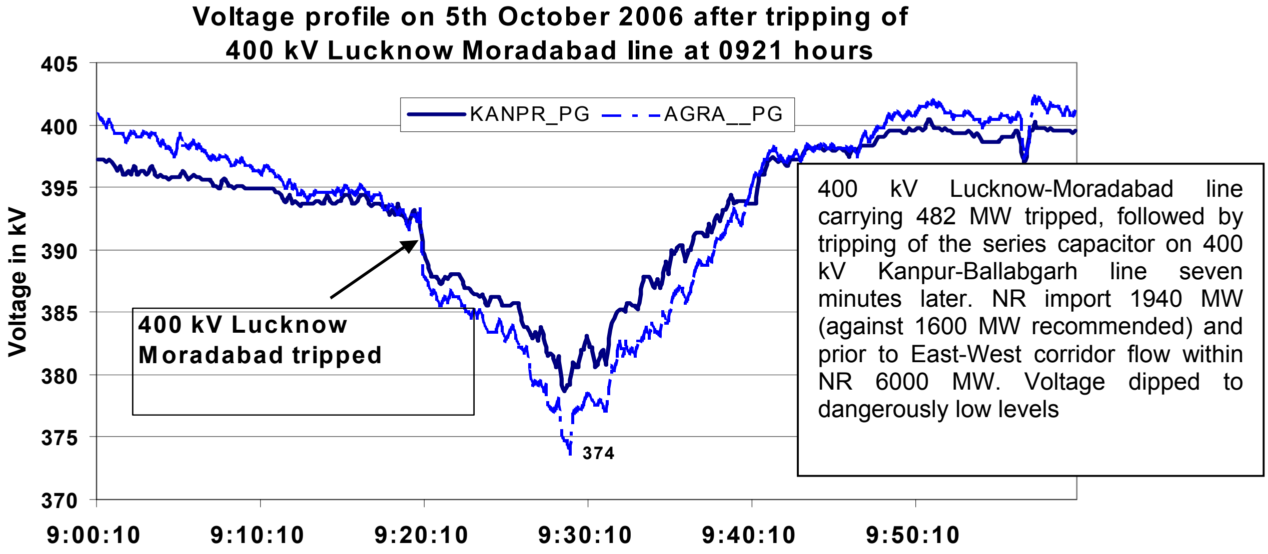
The formation of synchronous North-Central grid through has improved the stability of the grid by expanding the base for seamless sharing of resources as well as dynamic changes taking place anywhere in the entire synchronous interconnection. Each regional grid now participates in responding to the contingencies of other regions apart from their own. "*One can import/export trouble as well as help.*" [16] Failures in one location can propagate through the network at almost the speed of light [1].

Several such large contingencies **(19 nos. at an average of four incidents a month)** have already occurred post 26th August 2006 and up to 15th January 2007. This is indicated in the Table below under different categories (one incident could occur under two categories).

The system has to survive even under all kinds of credible contingencies in the first instance to give the system operators a chance to bring back the system to normal state quickly. Four system separations have already taken place; two of these occasions Maharastra system collapsed. The operators could quickly restore the system on all these occasions.

Tripping of Talcher-Kolar HVDC bipole carrying between 1000-2000 MW at any point of time to the Southern Region is again a credible contingency for the extended North and central grid. A System Protection Scheme (SPS), which trips the units at Talcher Stage-II, has been envisaged for this purpose. This SPS worked satisfactorily on 15th September 2006 and saved the system when the Talcher Kolar HVDC bipole carrying 1800 MW tripped.

When all the six units at Tala in Bhutan are operating round the clock (high hydro season), any disturbance in the Indian electricity grids would affect all the generating units in Bhutan viz. Tala, Kurichu and Chukha adding to 1335 MW capacity. During the winter off peak hours when these power stations are closed due to lean inflows, Bhutan draws power from the Indian electricity grid. Either way, a disturbance in the Indian grid would now affect neighbouring countries also. This emphasizes the importance of system security. Therefore the Available Transfer Capability should be seen as the scheduling (Long-term+ Short-term) as well as operating limit. Adherence to these limits would increase the likelihood of survival both during single as well as multiple contingencies.


Voltage profile on 5th October 2006 after tripping of 400 kV Lucknow Moradabad line at 0921 hours

400 kV Lucknow Moradabad tripped

400 kV Lucknow-Moradabad line carrying 482 MW tripped, followed by tripping of the series capacitor on 400 kV Kanpur-Ballabgarh line seven minutes later. NR import 1940 MW (against 1600 MW recommended) and prior to East-West corridor flow within NR 6000 MW. Voltage dipped to dangerously low levels

Figure 11: Impact of line tripping on system voltage.

Table 5: Likely consequences of contingency during various operating conditions

S No.	**Scenario**	**Likely consequences**
1	Real time transfers > **TTC**	System might not survive even a single element outage what to talk of a multiple contingency
2	**ATC** < Real time transfer< **TTC**	System might survive a single element tripping. But the chances of a cascading failure are high in case of a multiple contingency.
3	Real time transfer ≤ **ATC**	Chances of survival are high for single contingency and moderate for multiple contingency.

There might have been certain occasions when the system might have survived a major contingency even while operating beyond the specified operating limits. This does mean that the system could be allowed to operate at those levels. **Providential escape from the 'valley of death' on certain occasions cannot be a justification to operate the system at the edges.** Such incidents could at best be attributed to good Luck. But **"Luck" is not a part of our operating criteria**[17].

---

[17] Adapted from "Reliability Criteria and Operating limits", NERC, May 2007

Chapter: 6
Improvement of Transfer Capability

6.1 Congestion management in India

The regional grids in India are normally congestion free barring skewed dispatch scenarios. In fact the entire Unscheduled Mechanism as implemented in the Indian grid presupposes a constraint less transmission system. However subsequent to the formation of the NEW grid, the problem of line overloads has been experienced on many occasions. This gets aggravated in case of an extremely skewed generation despatch on account of abnormal operating conditions.

The identifiable reasons for occasional transmission constraints are as below:

1. Inadequate augmentation in the underlying network of state utilities
2. Erosion of the existing transmission capacity with state utilities on account of aging or inadequate maintenance
3. Inadequate appreciation of the line loading aspects of system security
4. Sharp changes in the interchange with the grid due to bulk load regulation and start-stop of hydro units at the hour boundaries.
5. Huge gap in the demand and supply and the pressure to meet the demand
6. General perception of UI as an infinite source
7. Market distortion caused by the difference in the ceiling UI rate and the marginal cost of generation from liquid fuel
8. Absence of line-loading component in the UI mechanism

Worldwide, the issue of congestion has been tackled through nodal or Locational Marginal Pricing (LMP). For instance, the PJM website has figures for the hourly day ahead and real time LMPs for 7866 buses in its system. The LMP varies from \$10/MWh to \$150/MWh for a typical day depending on the bus and the time of the day. At any specified bus, the ratio of maximum to minimum LMP varies between 3.0 to 3.5. At any hour boundary, the ratio of maximum to minimum LMP across the entire PJM system varies from 1.5 to 12.0.

In India no such congestion management tools exist and the Unscheduled Interchange (UI) mechanism does not have a line-loading component as brought out by the Joint Inadvertent Interchange Task Force (JIITF) Report [17]. Monitoring and enforcing compliance of RLDC directives with regard to system security is a difficult task due to limited **situational awareness** on the adverse effects of line overloading on the security of the grid. The grid separation, which took place on 22nd October 2006 is a clear example of this.

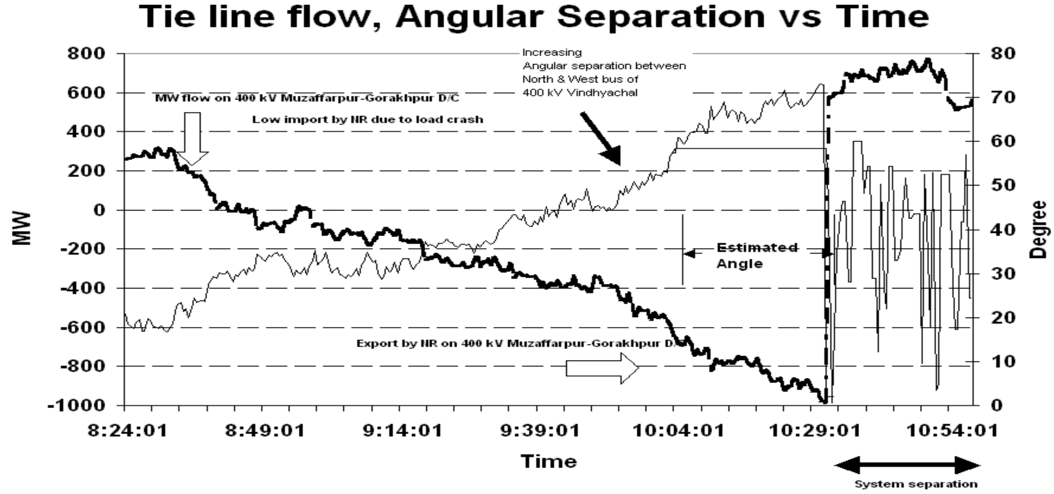


Figure 12:Angular Separation, tie line flow Vs Time

The graph above indicates how a gradual load reduction in Northern Region led to a sustained increase in export from Northern Region. Although there was no constraint in NR, the increase in export from NR led to overloading of network in Eastern Region followed by a system split when one of the heavily loaded lines had to be manually opened on account of sparking.

In light of the above rationalization of UI price vector could offer significant help in congestion management in India. The UI ceiling prices need to keep pace with the increase in fuel prices in the country. The following issues merit attention of the Honourable Commission as it has a bearing on system security as well as ATC.

- Tightening of the frequency band to a level of 49.5 Hz to 50.0 Hz from the currently allowed 49.0 to 50.5 Hz.
- Raise UI prices to a level, which enables scheduling/utilization of all liquid fuel resources (diesel/naphtha) well before 49.5 Hz and providing incentive for **N**ega**W**atts.
- Mandate a statutory reduction of UI volumes below 49.5 Hz and above 50 Hz and during system overloading conditions whenever declared by RLDCs. Mere price signals might alone not solve the grid security issue.
- Introduce a differential UI prices across geographical areas to manage congestion.

6.2 Ways to improve available transfer capability in India

CIGRE WG C1-2 studied the issue of ‘Maintenance of Acceptable Reliability in an Uncertain Environment by the Timely Provision of Network Capacity and Management of Constraints’. Some potential solutions to overcome issues highlighted in the draft report of this WG are reproduced below:

Quote:

- *Build and stimulate new generation in the close proximity of load centres, therefore eliminating the need for long power transfers*
- *Expand transmission capacity to physically accommodate new market*
    - *may not work effectively in highly meshed networks, as transmission paths could vary significantly*
- *Increased co-ordination of emergency procedures and planning and the contingency training of operators*
- *Reduce the chain of communication*
    - *Reduce time to carry out necessary actions*
- *Increase transparency to assist in planning*
- *The need for system planning and real time contingency assessment studies to cover the entire path of major normal and emergency power flows into a particular area, rather than to be constrained to the artificial boundaries of local technical and political jurisdictions and without much visibility beyond own borders.*
- *Design above N-1 rating? (for the complete system or certain parts?, say for bulk transmission and key transfer paths and corridors)*
- *The need to specify credible pre-contingency operating state (for example, N-1-1 starting from the intact system, etc).*
- *Increase Stakeholder awareness of system limitations and economic/reliability trade-off*
    - *May involve increasing utility charges to retain reliability*
- *Effective protection systems to contain the spread of the initial disturbance for low probability events and protect other parts of the system that can be saved*
- *May be a need for a co-coordinated official regulatory body governing reliability standards*
    - *Across borders of countries and states*
    - *Empowered to request information regarding standards and specifications that may help in increasing reliability from networks and generators*
- *Mandate duplicated or back-up protection so that a CB failure cannot blacken the whole system. This is particularly relevant for key switchyards and overlaps with their design (generation, load or transmission).*

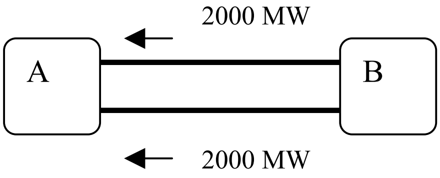
- *Coordinate maintenance, as many blackouts developed from situations where more than one item of plant was on maintenance.*
- *Limit the maximum number of plant that can simultaneously be on maintenance*
- *Consider introducing a new N-x-1 criterion to account for the maintenance practice, where x is the max number of components permitted to go out of service during an off-peak time defined as the specified % of the system peak load. The rationale is to translate the maintenance practice into the planning criteria to be studied in the planning time-horizons. Any violations should result in changes to the intended planned maintenance. The system reinforcements may be required only if the planned maintenance could not be re-scheduled. An example is the N-1-1 criterion at 80% peak load, starting from the intact system, that applies to the bulk transmission system and major load and generation centres.*
- *Installation of WAP (Wide Area Protection), WAMS (Wide Area Measurement System) and synchronised high-speed data recorders.*
- *Operational contingency plans to include events beyond those for which the system is planned.*

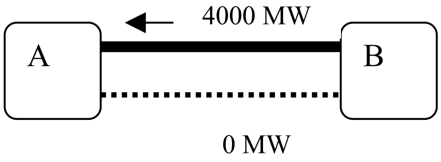
Unquote

Thus the transfer capability in the Indian context would improve gradually with the strengthening of network both at the State and Central level, availability of dynamic reactive reserves, improvement in the reliability of protection systems, religious implementation of the Under-frequency (UFR) and df/dt relay settings as well as Under Voltage Relay Load shedding (UVRLS), implementation of appropriate System Protection Schemes (SPS), Free Governor Mode of Operation (FGMO), availability of generation reserves and improvement in grid discipline. The possibility of enhancing the transfer capability through the above methods could be understood through the following illustration.

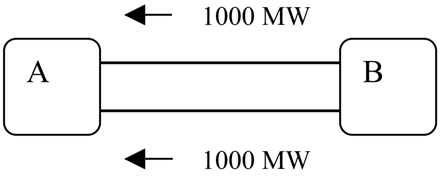
Illustration

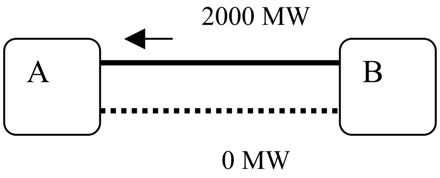
Suppose there are two areas with only two tie lines having total transmission capacity of 2000 MW each.





Assume that the tie lines are loaded up to their transmission capacity of 2000 MW. So the power transfer from B to A would be 4000 MW. In case one line trips the entire 4000 MW flowing from B to A would shift to the other line. This might result in large drop in terminal voltages and a cascade tripping of the other circuit as well. All this would happen within milliseconds resulting in loss of synchronism between the two areas even before the operator has a chance to take corrective action. In the absence of primary response by generators, the grid operator in area B would see a sharp rise in frequency and voltage while the operator in area A would see a sharp drop in frequency and voltage. Area B might see units tripping on over speed. Area A might be in greater trouble if the under frequency relay installed for automatic shedding of load, fails to operate. Thus it would be seen that the exporting area as well as the importing area is under grave risk in this scenario.





Now let us assume that the tie lines are loaded only up to 50 % of their capacity. This would mean that power flow on each line is allowed only up to 1000 MW, resulting in total transfer of power of 2000 MW from B to A. When one line trips the entire 2000 MW can comfortably be carried by the second circuit. The grid operators in either area could now take measures to reduce the power flow on the single circuit. This is also required because subsequent tripping of the remaining circuit would be equivalent to loss of 2000 MW generation in area A or a load throw off equivalent to 2000 MW in area B.

Thus the transmission capacity between A and B may be 4000 MW but the recommended operating limit due to security reasons would be 2000 MW only. **The operating limit could be increased if the safety net and the defense mechanism in the grid are strengthened. Automatic actions initiated through these mechanisms would contain or prevent the system from going into unstable zone.**

6.2.1 Implementation of Under Voltage Load Shedding (UVLS)

In the past there have been frequent incidents of voltage collapse due to heavy reactive drawals from the grid. This has become more important after the formation of the NEW grid when there are heavy power flows over long distances and inadequate load centre based generation on many occasions. Under Voltage Load Shedding at critical buses would greatly help in averting a voltage collapse and provide a self healing mechanism. Transfer capability of the network could thus be enhanced. While Under Frequency Relay Load Shedding (UFRLS) is very common in Indian power system, utilities are yet to appreciate the need for UVLS.

6.2.2 Design of System Protection Schemes (SPS) and deployment of Phasor Measurement Units (PMUs)

The Indian grids are on a high growth phase. Several Ultra Mega Power Projects (UMPPs) and high capacity transmission corridors (both AC as well as HVDC systems) are being planned and implemented. Outage of such high capacity generation or transmission, while being a rare event, is still a credible contingency. Adequate safety net in the form of SPS needs to be conceived at the planning stage itself. For existing systems, suitable SPS schemes have to be immediately conceived and implemented.

Designing suitable SPS for such large and highly meshed networks would require a meticulous understanding and co-ordination of power system operation, protective systems and high speed communication. HVDC Talcher-Kolar System Protection Scheme is already functioning successfully and has proved its utility in improving the system security. Similar schemes are envisaged for various interregional links in the NEW grid. Currently these schemes envisage only local measurements as well as decision-making. However with the growing complexity there would be a need for Wide Area Measurement Systems (WAMS) for decision making at a Central location. Worldwide, Phasor Measurement Units (PMUs) are deployed for Dynamic Security Assessment (DSA) in real time operation. Indian grids also need to explore the use of this technology so as to further exploit the capability of the transmission system.

6.2.3 Rejuvenation of inter-state tie lines owned by the state constituents

There are a number of 132 kV and 220 kV interstate lines owned by the state utilities. Some of these could also serve as inter-regional links. Most of these lines are operating either in parallel mode or radial mode. However some of these lines are lying utilized, (primarily due to commercial disputes between the owner utilities at either ends) which could otherwise have enhanced the transfer capability considerably. The RLDCs are making efforts to revive such links in the overall interest of the grid but only with a limited success.[18]

---

[18] After marathon efforts the 220 kV Kunihar-Panchkula double circuit line between Himachal Pradesh and Haryana that was lying unutilized for quite some time is now operating in synchronous mode. 220 kV Pusauli-Sahupuri is operating in radial mode to enhance the transfer capability between ER and NR. 220 kV Auraiya-Malanpur double circuit line is operating in parallel with 765 kV (charged at 400 kV) Agra-Gwalior and improved the synchronous connectivity between NR and WR.

Chapter-7

Conclusion and Suggestions

The formation of the "**NEW**" grid has taken us from regional grid operation to national grid operation. While on one hand this would enable regional grids to reap the all the benefits associated with synchronous interconnection, on the other hand they have to handle the inherent risks of a "**Large Grid**". There has been a **paradigm shift** in grid operation since the formation of the NEW grid. Now greater emphasis needs to be given on "**network reliability**", "**protection systems**", "**grid discipline**" and "**handling emergencies**". Operating such a large grid in a reliable manner is an onerous task, which can be discharged only with the **technical solidarity** and **co-operation** of all stakeholders. The experience so far in operating the NEW grid

The experience so far in operating the combined Northern and Central grid in synchronism has so far been positive. All the regions have been able to reap the benefits of synchronous operation. The operators have been able to successfully handle fifteen contingencies to date.

Grid discipline however continues to be a major area of concern and the SLDCs need to focus on this area in right earnest notwithstanding the compulsions to meet a high power demand even under a deficit situation. A ceiling on the volume of Unscheduled Interchange (UI), as initially proposed by NRLDC in its petition before the Honourable Central Electricity Regulatory Commission (CERC), needs to be seriously deliberated. How the UI mechanism could further complement grid security (enabling full scheduling of load centre based generation during low frequency or heavy line loadings, differential UI rates from region to region to relieve congestion) needs to be discussed threadbare. This would provide the right signals for enhancing reliability.

All the stakeholders also need to give a renewed thrust to network reliability. This would require:

i) Monitoring on an ongoing basis the progress and expediting all the generating units and transmission elements that are scheduled in the next one year so that time overruns are minimized and the inadequacy problem tackled.
ii) Meticulous planning of the generating unit and transmission line maintenance schedules and having a high degree of firmness in respect of these schedules so that forced outages could be minimized and the transfer capability of the network is worked out on a realistic basis,
iii) Have more of planned load shedding in case of a shortage in any state so that the SLDC is relieved of frequent instructions for emergency loadshedding in real time,
iv) Scheduling of reservoir based hydro generation in a manner that it complements grid security,
v) Continuous assessment of the network conditions in real time and its ability to handle contingencies,
vi) Better situational awareness at the SLDCs and RLDCs and prompt sharing of information in real time, particularly when a event has the potential of affecting the neighbouring system.

Further even after ensuring all the above steps are taken, simultaneous multiple contingencies cannot be ruled out totally and the grids need to have adequate safety net in the form of Under Frequency Relay Load Shedding (UFRLS), df/dt relay loadshedding, Under Voltage Load Shedding (UVLS). System Protection Scheme (SPS) to take care of simultaneous tripping of Rihand Dadri HVDC bipole needs to be commissioned expeditiously. Before we go for System Protection Schemes (SPS) entailing Wide Area Measurements (WAMs), there is a need for having schemes at individual power station level. Any simultaneous generation loss above say 800 MW must result in proportionate load shedding locally so that the combined North Central grid is not jeopardized.

Successful implementation of Open Access in transmission system requires a secure grid. The estimation of Transfer Capability is an involved process and is to be carried out by the Regional Load Despatch Centres (RLDCs) and the State Load Despatch Centres (SLDCs). These figures have to be worked out in a realistic fashion so that neither the security of the grid is compromised nor the scope for economy interchange reduced unduly. Calculations must take into account, among other factors, the network topology, planning criteria, operating philosophy, operating standards, market design, generation dispatch, spatial distribution of load/generation, behaviour of the utilities and the peculiarities of the Indian electricity grid. This requires **timely** and **accurate inputs** from several quarters.

The awareness and understanding of the concepts associated with transfer capability is still in a nascent stage in India. Learning from worldwide experience in respect of reliable operation of the bulk electric power system and assessment of transfer capability is a continuous process. An attempt has been made through this document to initiate a focused discussion in this area.

Three engineers in every RLDC have been designated as "**Reliability Coordinator**". They have been assigned the responsibility to carry out all the necessary studies and exercise for assessment of the transfer capability and also suggest measures to enhance the security of the integrated grid. Several workshops have been conducted to sensitize the stakeholders on the issue and also ensure transparency in evaluation of network capability. Similar efforts are required at the state level to strengthen the understanding of grid operation in India.

Inclusion of these concepts in the IEGC could help in developing it further. Moreover the distinguishing features of the Indian grid as discussed above amply suggest need for **evolution of operating criteria in line with the planning criteria** existing for planning purposes.

It is important that this subject is taken up further and the next practices identified and implemented. It is an area requiring close coordination between the system operators, system planners, policy makers, regulators and all stakeholders including academia.

References

[1] **Thomas J. Overbye**, ‘Re-engineering the Electric Grid’, American Scientist, May-June 2000.

[2] **North American Electric Reliability Corporation**, ‘Transmission Transfer Capability A Reference Document for Calculating and Reporting the Electric Power Transfer Capability of Interconnected Electric Systems ’ –May 1995

[3] **North American Electric Reliability Corporation**, ‘Available Transfer Capability Definitions and Determination’ -June 1996.

[4] **North American Electric Reliability Corporation** ATC Working Group, ‘Transmission Capability Margins and their use in ATC determination –White Paper’, 17th June 1999.

[5] **Peter W. Sauer**, ‘Technical Challenges of Computing Available Transfer Capability (ATC) in Electric Power Systems’, PSERC 97-04, 30th Annual Hawaii International Conference on System Sciences, Jan 7-10, 1997.

[6] **Power System Engineering Research Centre**, “Electric Power Transfer Capability: Concepts, Applications, Sensitivity and Uncertainty”, PSERC publication 01-34, November 2001, http://www.pserc.wisc.edu

[7] **Central Electricity Authority, Ministry of Power, Government of India**, ‘Manual on Transmission Planning Criteria’, June 1994

[8] **Central Electricity Regulatory Commission**, “Indian Electricity Grid Code” Effective from 1st April 2006

[9] **Central Board for Irrigation and Power,** ‘Thermal limits of various conductors used in transmission system’, Technical Report no. 77, May 1991

[10] **H.P. ST. Clair**, ‘Practical Concepts in Capability and Performance of Transmission Lines’, AIEE Transactions, Vol 72, Part III, December 1953, pp 1152-1157

[11] **Prabha Kundur**, ‘Power System Stability and Control’, EPRI, Power system Engineering Series, Tata McGraw-Hill, 3rd Reprint 2007

[12] **Steven Stoft,** “Power System Economics, Designing Markets for Electricity”, Wiley, IEEE press, 2002

[13] **Dr. Mohammad Shahidehpour**, ‘Electricity Restructuring and the Role of Security in Power Systems Operation and Planning’, IEEE tutorial, New Delhi, April 2006

[14] **North American Electric Reliability Corporation**, ‘*Reliability Criteria and Operating Limits Concepts*’, Version 4 Draft 8, 2nd May 2007

[15] **Roy Billinton, Ronald N. Allan**, ‘Reliability Evaluation of Power Systems’, second edition, Plenum press, New York & London

[16] **Charles Concordia**, ‘Interconnections-Tutorial’ Electric Power and Energy Systems., Vol. 3, No.3, July 1981, pp 167-174

[17] **North American Electric Reliability Corporation**, ‘Joint Inadvertent Interchange Task Force (JIITF) White Paper: Recommendations for the Wholesale Electric Industry of North America: Inadvertent Interchange, Draft 5d’, May 10, 2002

[18] **Central Electricity Regulatory Commission** order on “Open Access in Transmission” dated 30th January 2004, Sou motu Petition no. 48/2003 and “Regulations for Open Access in Interstate Transmission 2004” issued on 30th January 2004

[19] **Government of India**, “Electricity Act 2003”, 2nd June 2003

Appendix-1: Instances of simultaneous outage of several elements

A. Incidents of multiple units tripping

S No.	Station	Date & Time	Number of units tripped	Generation loss in MW	Remarks
1	Ropar	30th Aug 2006 (1332 hrs)	3	600	--
2	Suratgarh	4th Oct 2006 (1822 hrs)	5	1200	600 MW load throw off in Rajasthan
3	Singrauli	13th Nov 2006 (1432 hrs)	4	800	CW pump failure
4	Anpara	15th Nov 2006 (1121 hrs)	5	1500	Fault on 132 kV Pipri bus; Auxiliary supply failure; Flow on 400 kV Purnea-Muzaffarpur one circuit touched 1000 MW (other ckt out)
5	Obra	3rd Nov 2006 (1312 hrs)	3	400	CT blast; Bus bar protection failure Fault cleared by lines from remote end; All 400 kV lines tripped.
6	Ropar	7th Dec 2006 (0042 hrs)	4	800	--
7	Farraka, Kahalgaon & Tenughat	6th Jan 2007 (1610 hrs)	8 (2+4+2)	1750	Fault on 400 kV Biharsharif-Kahalgaon ckt-II fed from Biharsharif end for 2.5 minutes.

B Simultaneous outage of multiple transmission elements

S No.	Details	Date & Time	Remarks
1	All three 400/220 kV ICTs at Muradnagar	12th Sep 2006 (1220 hrs)	750 MW load throw off in U.P.
2	400 kV Lucknow-Moradabad + Series capacitor of 400 kV Kanpur-Ballabgarh tripping seven minutes later	5th Oct 2006 (1022 hrs.)	400 kV Lucknow-Moradabad was carrying 482 MW. Sharp drop in voltages in NR.
3	Six 400 kV lines and four 220 kV lines at 400 kV Hissar substation	5th Oct 2006 (2025 hrs)	Manual opening of lines after observing a sparking.
4	Six 400 kV elements lost at 400 kV Unnao substation	22nd October (0540 hrs)	LBB operation
5	All 400 kV lines (3 nos.) from 400 kV Obra substation of (Also A.5 above)	3rd Nov 2006 (1312 hrs)	CT blast Bus bar protection fail Fault cleared by lines from remote end.

C. Incidents of auto restarts/tripping due to fog

S No.	Dates	Area affected by fog	Auto restarts observed	Number of lines affected by auto restarts	Number of line tripping	Corridors affected
1	23rd Dec 2006 early morning	Western U.P, Delhi, Haryana	10	4	22	7
2	Night of 26th /27th Dec 2006	Delhi, Western U.P.	21	7	9	3
3	Night of 30th / 31st Dec 2006	Southeast & Eastern U.P	6	5	14	2
4	Night of 31st Dec 06/ 1st Jan 07	Western & Eastern U.P, Delhi, Haryana	13	7	21	7

D. Tripping of HVDC Bipole and HVDC back-to-back inter regional links

S No.	Element	Date & Time	Remarks
1.	ER-NR HVDC back-to-back link	6th Sep 2006 (1548 hrs)	WR-NR HVDC back-to-back was already under shutdown
2.	Talcher-Kolar HVDC Bipole	15th Sep 2006	Bipole was carrying 1800 MW from ER to SR. System Protection Scheme installed for the purpose operated successfully and tripped units at Talcher-II. System survived
3.	ER-NR HVDC back-to-back link (Also A.7 above)	6th January 2007 (1610 hrs)	Fault on 400 kV Biharsharif-Kahalgaon Ckt 2 fed from Biharsharif end for 2.5 minutes.1750 MW generation loss at Farakka, Kahalgaon and Tenughat in Eastern Region

E. Load Crash

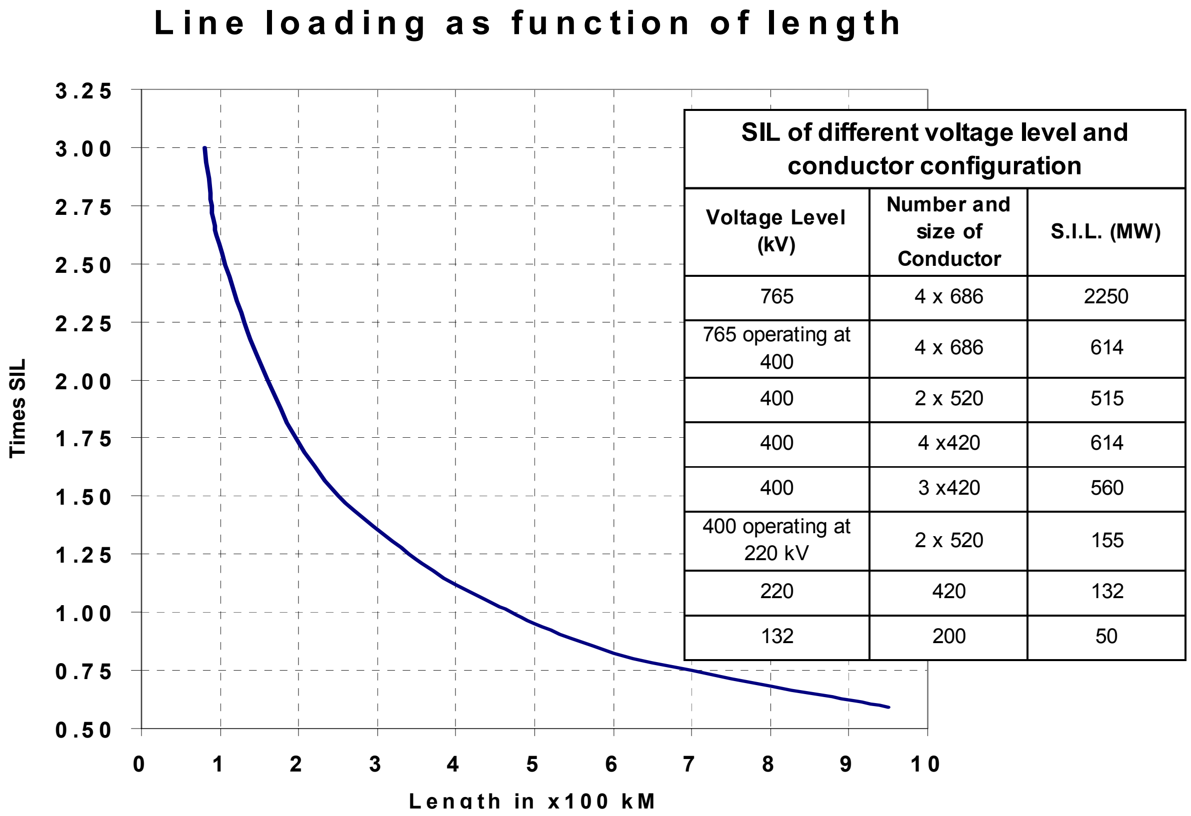
S No.	Region	Date	Remarks
1.	Northern Region (NR)	2nd /3rd Sep 2006	1800 MW export from NR

F. System separation

S No.	System separated	Date & Time	Initiating cause	Remarks
1	NER+ Bhutan + NR system from rest of the Central grid	15th Sep 2006 (1851 hrs)	Manual opening of one circuit of 400 kV Farraka-Malda-1 carrying Tripping of second circuit	Systems survived and were synchronised at 0321 hrs of 16th Sep 2006
2	Southern Orissa + WR system from rest of the grid	22nd Oct 2006 (1031 hrs)	Manual opening of 400 kV Jamshedpur-Rourkela-I carrying 670 MW due to isolator sparking followed by cascade trippings.	Systems survived & synchronised at 1135 hours.

Appendix-2: St. Clair’s Curve

The operating limits for transmission lines may be taken as minimum of thermal rating of conductors the line maximum permissible line loadings derived from St. Clair’s curve.


Line loading as function of length

SIL of different voltage level and conductor configuration		
Voltage Level (kV)	**Number and size of Conductor**	**S.I.L. (MW)**
765	4 x 686	2250
765 operating at 400	4 x 686	614
400	2 x 520	515
400	4 x420	614
400	3 x420	560
400 operating at 220 kV	2 x 520	155
220	420	132
132	200	50

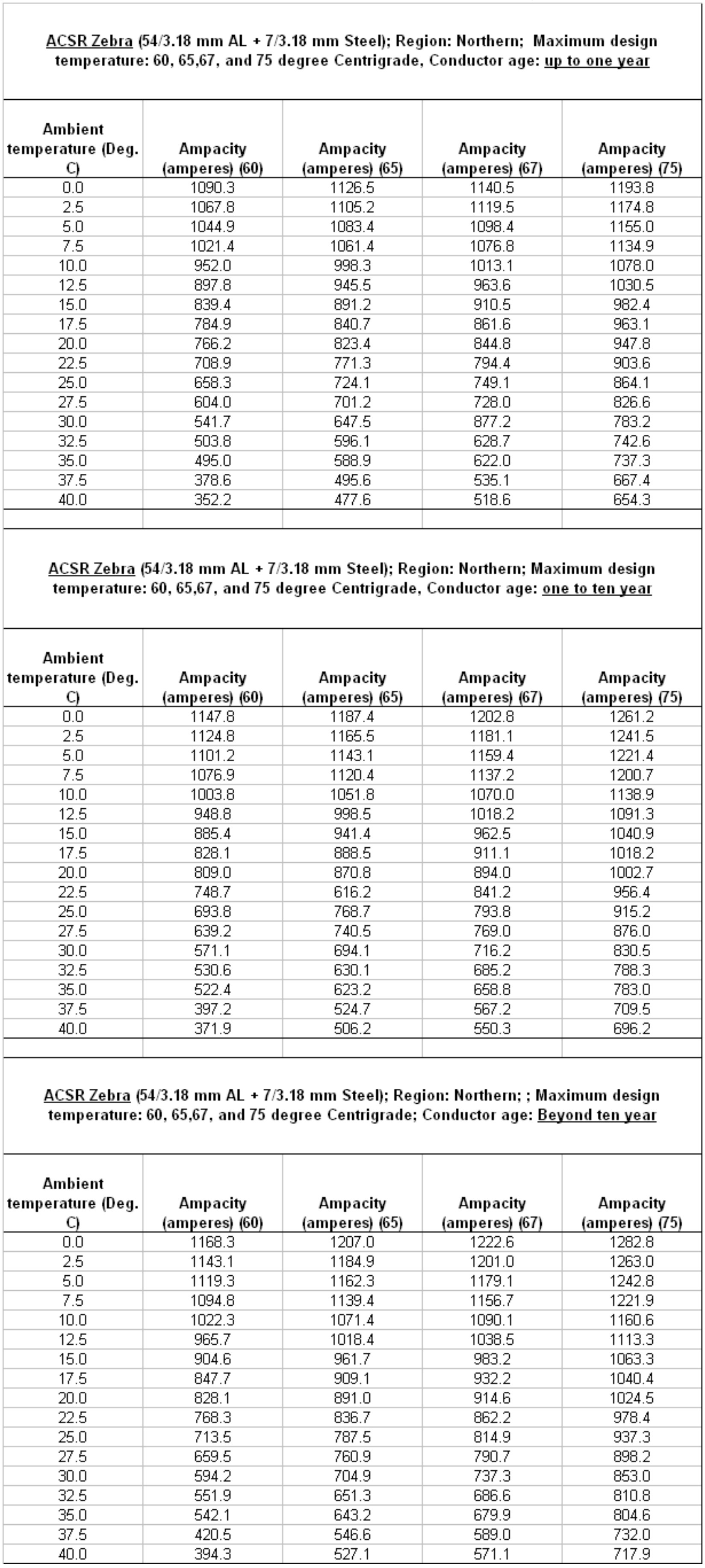
SIL given in table above is for uncompensated line. If k is the compensation then
For shunt compensated line: SIL modified = SIL x Square root (1-k)
For a series compensated line: SIL modified = SIL divided by Square root (1-k)

Further to taken into account the line length one needs to multiple the modified SIL with the multiplying factor derived from St. Clair's curve. The derived steady state limit for a line would be = SIL modified x factor from St. Clair's curve

Illustration:
400 kV Unnao-Bareli line in Northern Region of India is 250 km long and has 50 MVAr reactors at either ends. The conductor used is ACSR twin moose.
SIL for this line would be 515 MW as seen in the table
Reactor rating at 400 kV = 45.35 MVAr
Total compensation= 90.70
Charging MVAr = 139 MVAr
k = 90.70/139 = 0.65
sqrt(1-k) = 0.59
Multipyling factor from St. Clair's curve = 1.5
Derived steady state limit = 515 x 0.59 x 1.5 = 456 MW

Appendix-3: Ampacity of Conductors

Source: CBIP Technical Report 77 of May 1991



ACSR Zebra (54/3.18 mm AL + 7/3.18 mm Steel); Region: Northern; Maximum design temperature: 60, 65,67, and 75 degree Centrigrade, Conductor age: up to one year

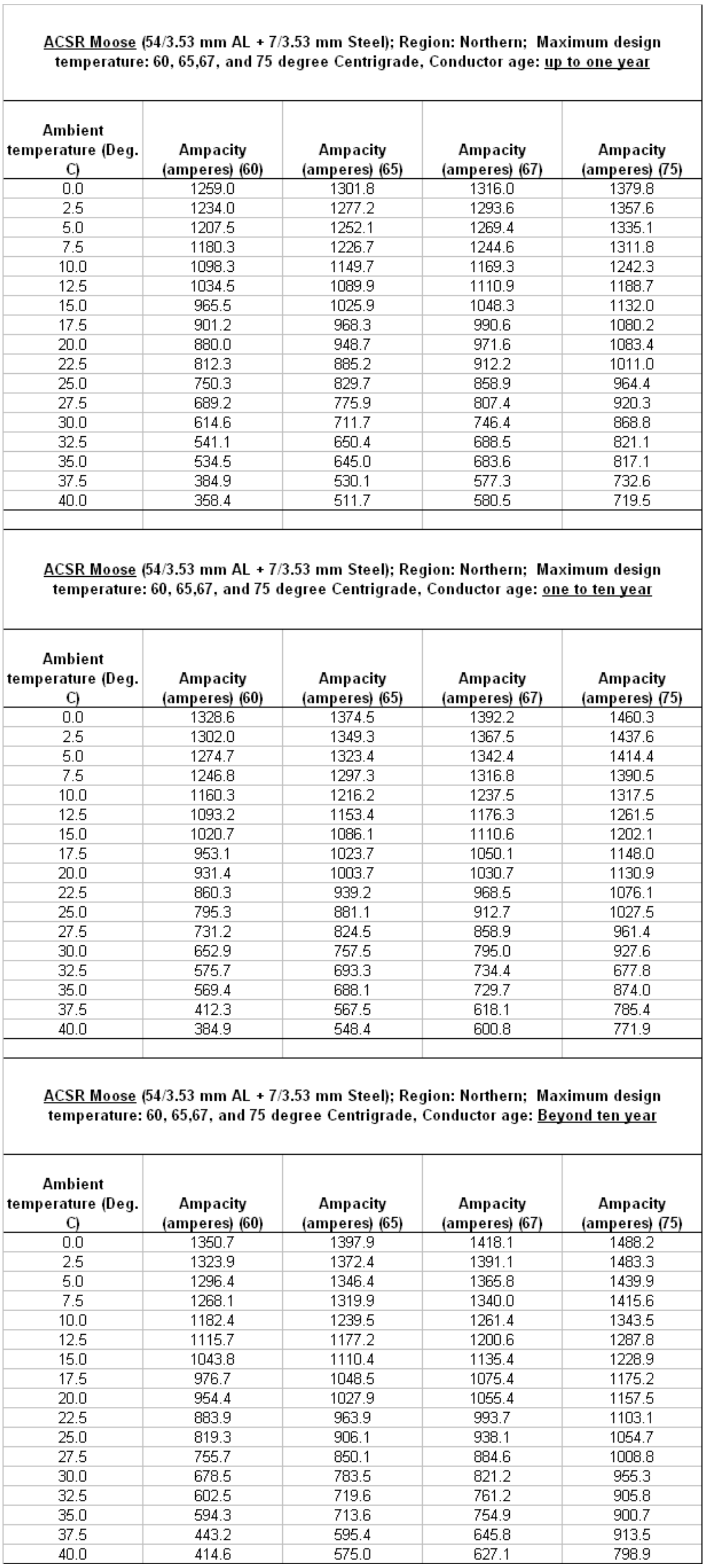
Ambient temperature (Deg. C)	Ampacity (amperes) (60)	Ampacity (amperes) (65)	Ampacity (amperes) (67)	Ampacity (amperes) (75)
0.0	1090.3	1126.5	1140.5	1193.8
2.5	1067.8	1105.2	1119.5	1174.8
5.0	1044.9	1083.4	1098.4	1155.0
7.5	1021.4	1061.4	1076.8	1134.9
10.0	952.0	998.3	1013.1	1078.0
12.5	897.8	945.5	963.6	1030.5
15.0	839.4	891.2	910.5	982.4
17.5	784.9	840.7	861.6	963.1
20.0	766.2	823.4	844.8	947.8
22.5	708.9	771.3	794.4	903.6
25.0	658.3	724.1	749.1	864.1
27.5	604.0	701.2	728.0	826.6
30.0	541.7	647.5	877.2	783.2
32.5	503.8	596.1	628.7	742.6
35.0	495.0	588.9	622.0	737.3
37.5	378.6	495.6	535.1	667.4
40.0	352.2	477.6	518.6	654.3

ACSR Zebra (54/3.18 mm AL + 7/3.18 mm Steel); Region: Northern; Maximum design temperature: 60, 65,67, and 75 degree Centrigrade, Conductor age: one to ten year

Ambient temperature (Deg. C)	Ampacity (amperes) (60)	Ampacity (amperes) (65)	Ampacity (amperes) (67)	Ampacity (amperes) (75)
0.0	1147.8	1187.4	1202.8	1261.2
2.5	1124.8	1165.5	1181.1	1241.5
5.0	1101.2	1143.1	1159.4	1221.4
7.5	1076.9	1120.4	1137.2	1200.7
10.0	1003.8	1051.8	1070.0	1138.9
12.5	948.8	998.5	1018.2	1091.3
15.0	885.4	941.4	962.5	1040.9
17.5	828.1	888.5	911.1	1018.2
20.0	809.0	870.8	894.0	1002.7
22.5	748.7	616.2	841.2	956.4
25.0	693.8	768.7	793.8	915.2
27.5	639.2	740.5	769.0	876.0
30.0	571.1	694.1	716.2	830.5
32.5	530.6	630.1	685.2	788.3
35.0	522.4	623.2	658.8	783.0
37.5	397.2	524.7	567.2	709.5
40.0	371.9	506.2	550.3	696.2

ACSR Zebra (54/3.18 mm AL + 7/3.18 mm Steel); Region: Northern; ; Maximum design temperature: 60, 65,67, and 75 degree Centrigrade; Conductor age: Beyond ten year

Ambient temperature (Deg. C)	Ampacity (amperes) (60)	Ampacity (amperes) (65)	Ampacity (amperes) (67)	Ampacity (amperes) (75)
0.0	1168.3	1207.0	1222.6	1282.8
2.5	1143.1	1184.9	1201.0	1263.0
5.0	1119.3	1162.3	1179.1	1242.8
7.5	1094.8	1139.4	1156.7	1221.9
10.0	1022.3	1071.4	1090.1	1160.6
12.5	965.7	1018.4	1038.5	1113.3
15.0	904.6	961.7	983.2	1063.3
17.5	847.7	909.1	932.2	1040.4
20.0	828.1	891.0	914.6	1024.5
22.5	768.3	836.7	862.2	978.4
25.0	713.5	787.5	814.9	937.3
27.5	659.5	760.9	790.7	898.2
30.0	594.2	704.9	737.3	853.0
32.5	551.9	651.3	686.6	810.8
35.0	542.1	643.2	679.9	804.6
37.5	420.5	546.6	589.0	732.0
40.0	394.3	527.1	571.1	717.9



ACSR Moose (54/3.53 mm AL + 7/3.53 mm Steel); Region: Northern; Maximum design temperature: 60, 65,67, and 75 degree Centrigrade, Conductor age: up to one year

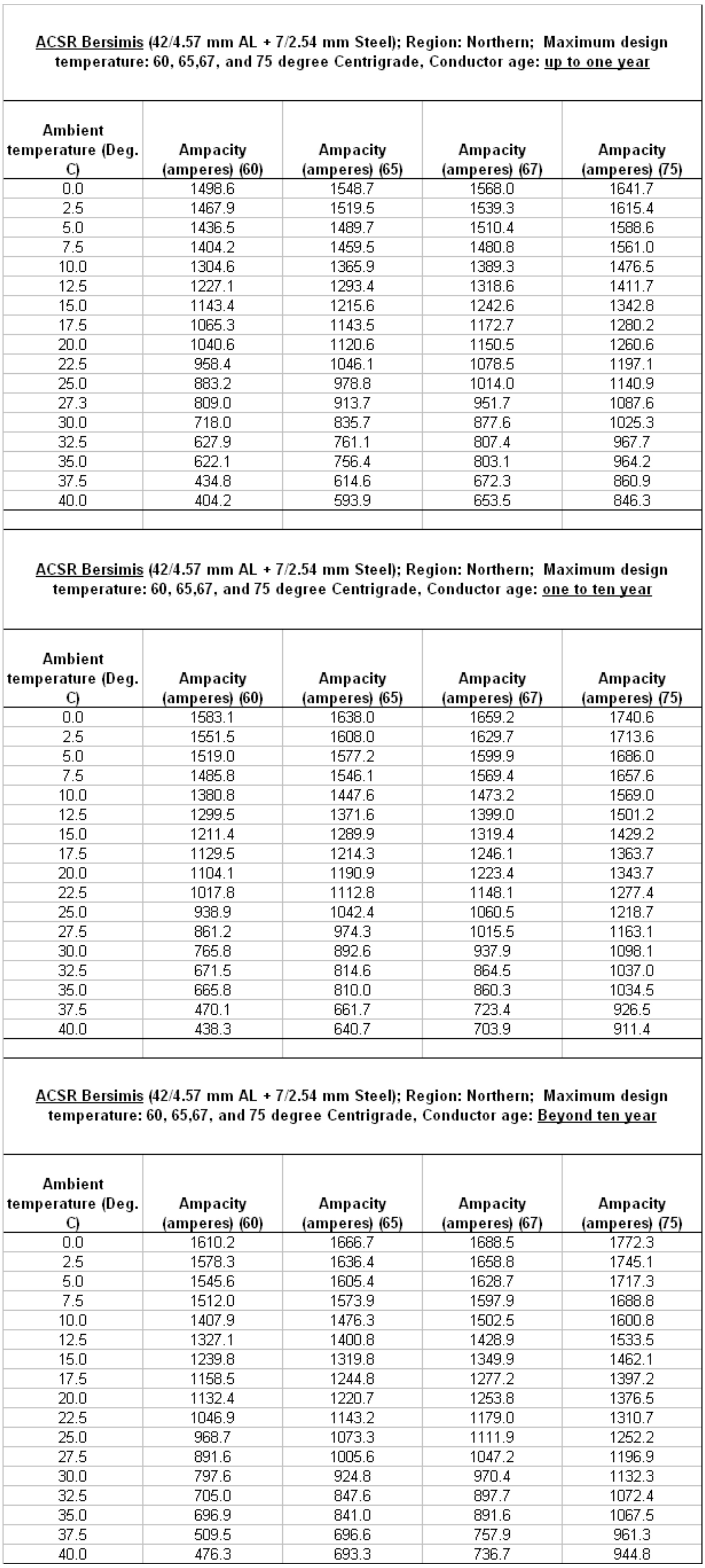
Ambient temperature (Deg. C)	Ampacity (amperes) (60)	Ampacity (amperes) (65)	Ampacity (amperes) (67)	Ampacity (amperes) (75)
0.0	1259.0	1301.8	1316.0	1379.8
2.5	1234.0	1277.2	1293.6	1357.6
5.0	1207.5	1252.1	1269.4	1335.1
7.5	1180.3	1226.7	1244.6	1311.8
10.0	1098.3	1149.7	1169.3	1242.3
12.5	1034.5	1089.9	1110.9	1188.7
15.0	965.5	1025.9	1048.3	1132.0
17.5	901.2	968.3	990.6	1080.2
20.0	880.0	948.7	971.6	1083.4
22.5	812.3	885.2	912.2	1011.0
25.0	750.3	829.7	858.9	964.4
27.5	689.2	775.9	807.4	920.3
30.0	614.6	711.7	746.4	868.8
32.5	541.1	650.4	688.5	821.1
35.0	534.5	645.0	683.6	817.1
37.5	384.9	530.1	577.3	732.6
40.0	358.4	511.7	580.5	719.5

ACSR Moose (54/3.53 mm AL + 7/3.53 mm Steel); Region: Northern; Maximum design temperature: 60, 65,67, and 75 degree Centrigrade, Conductor age: one to ten year

Ambient temperature (Deg. C)	Ampacity (amperes) (60)	Ampacity (amperes) (65)	Ampacity (amperes) (67)	Ampacity (amperes) (75)
0.0	1328.6	1374.5	1392.2	1460.3
2.5	1302.0	1349.3	1367.5	1437.6
5.0	1274.7	1323.4	1342.4	1414.4
7.5	1246.8	1297.3	1316.8	1390.5
10.0	1160.3	1216.2	1237.5	1317.5
12.5	1093.2	1153.4	1176.3	1261.5
15.0	1020.7	1086.1	1110.6	1202.1
17.5	953.1	1023.7	1050.1	1148.0
20.0	931.4	1003.7	1030.7	1130.9
22.5	860.3	939.2	968.5	1076.1
25.0	795.3	881.1	912.7	1027.5
27.5	731.2	824.5	858.9	961.4
30.0	652.9	757.5	795.0	927.6
32.5	575.7	693.3	734.4	677.8
35.0	569.4	688.1	729.7	874.0
37.5	412.3	567.5	618.1	785.4
40.0	384.9	548.4	600.8	771.9

ACSR Moose (54/3.53 mm AL + 7/3.53 mm Steel); Region: Northern; Maximum design temperature: 60, 65,67, and 75 degree Centrigrade, Conductor age: Beyond ten year

Ambient temperature (Deg. C)	Ampacity (amperes) (60)	Ampacity (amperes) (65)	Ampacity (amperes) (67)	Ampacity (amperes) (75)
0.0	1350.7	1397.9	1418.1	1488.2
2.5	1323.9	1372.4	1391.1	1483.3
5.0	1296.4	1346.4	1365.8	1439.9
7.5	1268.1	1319.9	1340.0	1415.6
10.0	1182.4	1239.5	1261.4	1343.5
12.5	1115.7	1177.2	1200.6	1287.8
15.0	1043.8	1110.4	1135.4	1228.9
17.5	976.7	1048.5	1075.4	1175.2
20.0	954.4	1027.9	1055.4	1157.5
22.5	883.9	963.9	993.7	1103.1
25.0	819.3	906.1	938.1	1054.7
27.5	755.7	850.1	884.6	1008.8
30.0	678.5	783.5	821.2	955.3
32.5	602.5	719.6	761.2	905.8
35.0	594.3	713.6	754.9	900.7
37.5	443.2	595.4	645.8	913.5
40.0	414.6	575.0	627.1	798.9



ACSR Bersimis (42/4.57 mm AL + 7/2.54 mm Steel); Region: Northern; Maximum design temperature: 60, 65,67, and 75 degree Centrigrade, Conductor age: up to one year

Ambient temperature (Deg. C)	Ampacity (amperes) (60)	Ampacity (amperes) (65)	Ampacity (amperes) (67)	Ampacity (amperes) (75)
0.0	1498.6	1548.7	1568.0	1641.7
2.5	1467.9	1519.5	1539.3	1615.4
5.0	1436.5	1489.7	1510.4	1588.6
7.5	1404.2	1459.5	1480.8	1561.0
10.0	1304.6	1365.9	1389.3	1476.5
12.5	1227.1	1293.4	1318.6	1411.7
15.0	1143.4	1215.6	1242.6	1342.8
17.5	1065.3	1143.5	1172.7	1280.2
20.0	1040.6	1120.6	1150.5	1260.6
22.5	958.4	1046.1	1078.5	1197.1
25.0	883.2	978.8	1014.0	1140.9
27.3	809.0	913.7	951.7	1087.6
30.0	718.0	835.7	877.6	1025.3
32.5	627.9	761.1	807.4	967.7
35.0	622.1	756.4	803.1	964.2
37.5	434.8	614.6	672.3	860.9
40.0	404.2	593.9	653.5	846.3

ACSR Bersimis (42/4.57 mm AL + 7/2.54 mm Steel); Region: Northern; Maximum design temperature: 60, 65,67, and 75 degree Centrigrade, Conductor age: one to ten year

Ambient temperature (Deg. C)	Ampacity (amperes) (60)	Ampacity (amperes) (65)	Ampacity (amperes) (67)	Ampacity (amperes) (75)
0.0	1583.1	1638.0	1659.2	1740.6
2.5	1551.5	1608.0	1629.7	1713.6
5.0	1519.0	1577.2	1599.9	1686.0
7.5	1485.8	1546.1	1569.4	1657.6
10.0	1380.8	1447.6	1473.2	1569.0
12.5	1299.5	1371.6	1399.0	1501.2
15.0	1211.4	1289.9	1319.4	1429.2
17.5	1129.5	1214.3	1246.1	1363.7
20.0	1104.1	1190.9	1223.4	1343.7
22.5	1017.8	1112.8	1148.1	1277.4
25.0	938.9	1042.4	1060.5	1218.7
27.5	861.2	974.3	1015.5	1163.1
30.0	765.8	892.6	937.9	1098.1
32.5	671.5	814.6	864.5	1037.0
35.0	665.8	810.0	860.3	1034.5
37.5	470.1	661.7	723.4	926.5
40.0	438.3	640.7	703.9	911.4

ACSR Bersimis (42/4.57 mm AL + 7/2.54 mm Steel); Region: Northern; Maximum design temperature: 60, 65,67, and 75 degree Centrigrade, Conductor age: Beyond ten year

Ambient temperature (Deg. C)	Ampacity (amperes) (60)	Ampacity (amperes) (65)	Ampacity (amperes) (67)	Ampacity (amperes) (75)
0.0	1610.2	1666.7	1688.5	1772.3
2.5	1578.3	1636.4	1658.8	1745.1
5.0	1545.6	1605.4	1628.7	1717.3
7.5	1512.0	1573.9	1597.9	1688.8
10.0	1407.9	1476.3	1502.5	1600.8
12.5	1327.1	1400.8	1428.9	1533.5
15.0	1239.8	1319.8	1349.9	1462.1
17.5	1158.5	1244.8	1277.2	1397.2
20.0	1132.4	1220.7	1253.8	1376.5
22.5	1046.9	1143.2	1179.0	1310.7
25.0	968.7	1073.3	1111.9	1252.2
27.5	891.6	1005.6	1047.2	1196.9
30.0	797.6	924.8	970.4	1132.3
32.5	705.0	847.6	897.7	1072.4
35.0	696.9	841.0	891.6	1067.5
37.5	509.5	696.6	757.9	961.3
40.0	476.3	693.3	736.7	944.8

This page has been intentionally left blank.

Index