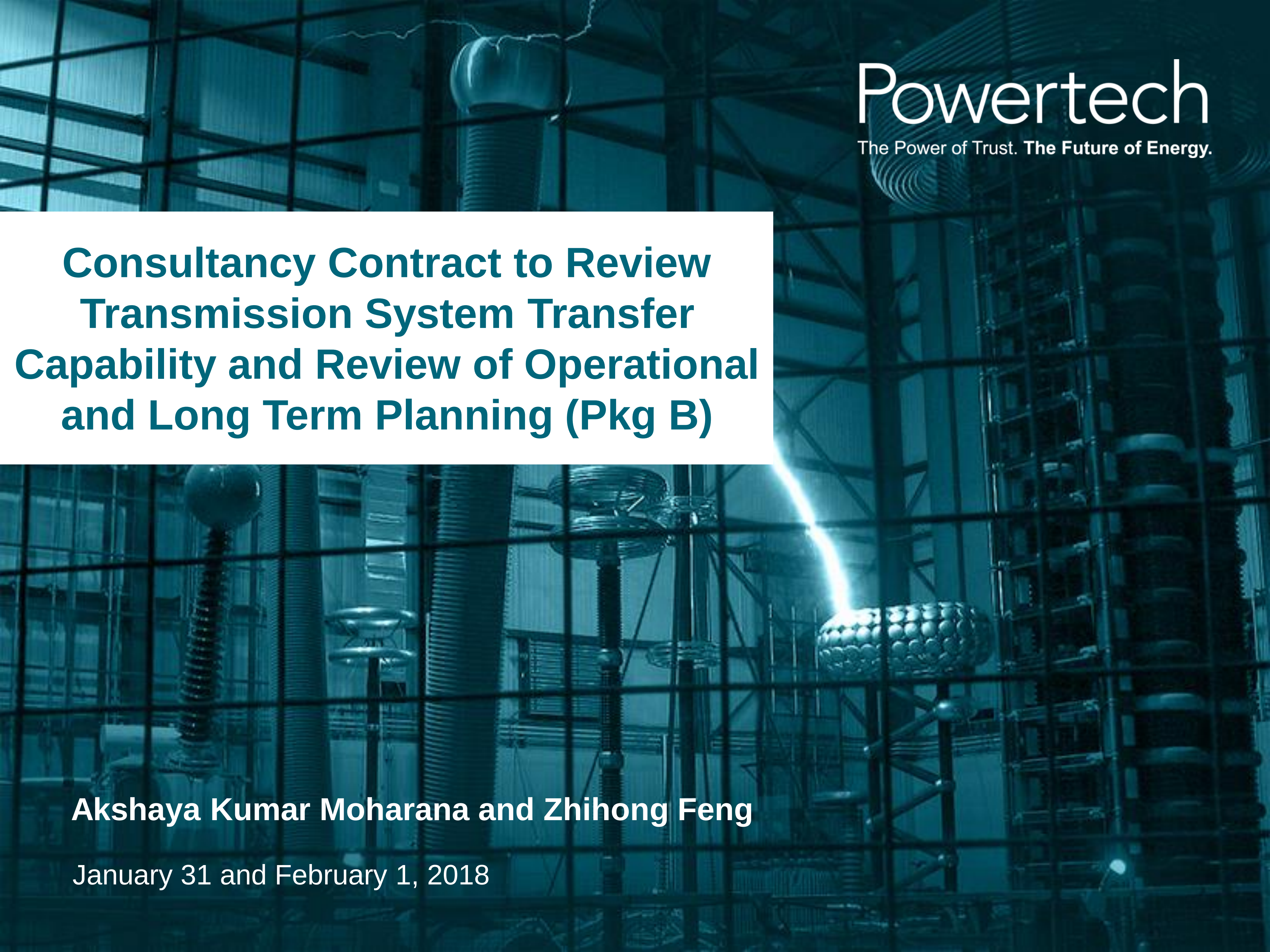


Powertech

The Power of Trust. **The Future of Energy.**

Consultancy Contract to Review Transmission System Transfer Capability and Review of Operational and Long Term Planning (Pkg B)

Akshaya Kumar Moharana and Zhihong Feng

January 31 and February 1, 2018

Introduction: Project Background

- Ministry of Power, Government of India constituted a "Taskforce on Power System Analysis under Contingencies" in Dec. 2012 as a follow up of the recommendations of Enquiry Committee under Chairperson, Central Electricity Authority (CEA) on Grid Disturbances of 2012 in Indian Grid
- The Taskforce broadly made recommendations regarding analysis of the network behavior under normal and contingency scenarios
- In view of necessity to ensure secure and reliable operation of the national grid, and for optimizing the transfer of power through the inter-regional lines/corridors, it was also found necessary to review the criteria related to transfer capability of these lines/corridors
- Thus Powertech Labs, Inc. (PLI) was contracted to perform 6 tasks

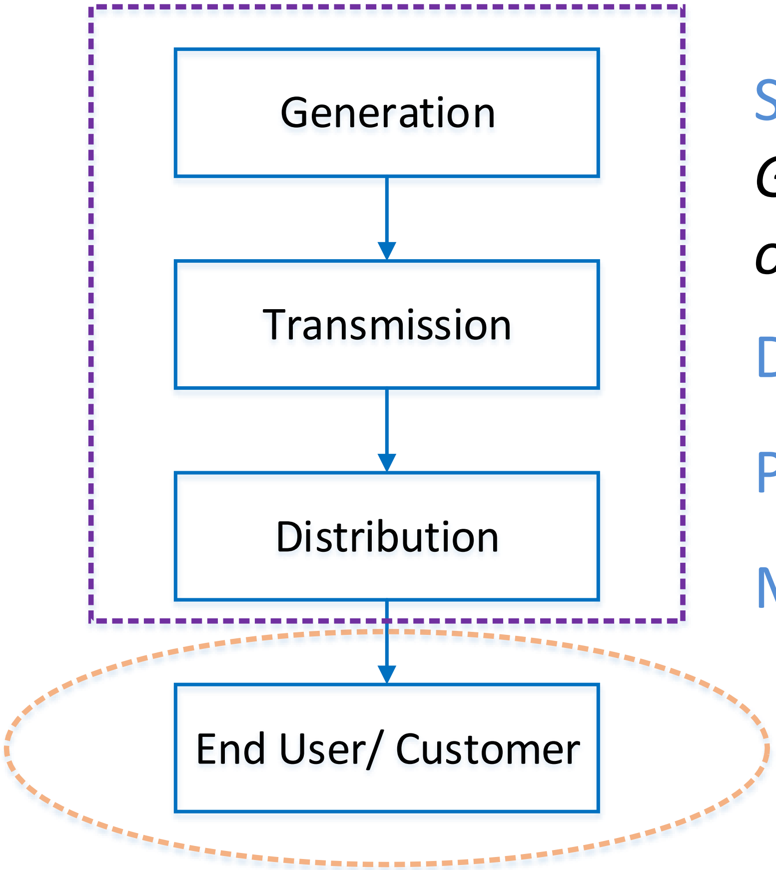
Project Tasks

- **Task I: Examination and recommendation of methodology for optimum calculation of transfer capability in the planning and the operational horizons**
- Task II: Calculation of transfer capability for the entire country
- Task III: Guidelines for developing and implementing system protection schemes and islanding schemes, and review of existing schemes
- Task IV: Operational planning and long term planning for secure and efficient operation of the grid
- Task V: Suitable suggestions in the Regulatory framework to ensure secure and efficient grid operation
- Task VI: Review of the tuning of all power electronic devices and suggesting retuning of setting of these devices, as per "Taskforce Report on Power System Analysis"

Task I Specifics

- **Power System Transfer Capability**
- **Determination of Transfer Capability**
    - *Total Transfer Capability (TTC)*
    - *Transmission Reliability Margin (TRM)*
    - *Capacity Benefit Margin (CBM)*
    - *Available Transfer Capability (ATC*)
- **Transfer Capability Calculation Methodologies used by CTU and POSOCO**
- **Transfer Capability Calculation Methodologies Used by Various TSPs/TOPs/ISOs in the world**
- **Recommendations**

Power Industry Structure



Traditional Power Industry Structure

Supply: *Vertically Integrated Suppliers Generation, Transmission and Distribution owned by Govt. Utilities*

Demand: *Native Load*

Product: *Electric Energy*

Market: *No Competitive Marketplace*

Powertech

Power System Restructure

Why?

- Scarcity of financial resources
- Need for increased technical and commercial efficiency
- Functional separation of generation, transmission, and distribution into different administrative divisions
- Need for nondiscriminatory grid access
- Absence of competition

Benefits:

- ✓ Electricity price may go down
- ✓ Choice for customers
- ✓ Customer-centric service
- ✓ Innovation

Which Segments are Competitive?

- Transmission
- Generation
- Distribution (separate jurisdiction)

Transmission Access Reforms

Objective:

Provide non-discriminatory access to transmission system.

Technical Aspect:

Transfer Capability

- It refers to the amount of electric power that can be delivered reliably through a transmission network from one place to another over all transmission lines (or paths) between those areas under specified system conditions.
- It's an indicator of the relative security of an interconnected power system which is robust and flexible to accommodate inter-area transfers.
- Transfer capability computations are also essential for both the planning and operation of a power system with respect to system security and reliability.

Determination of Transfer Capability

Transfer Capability is calculated through computer simulations of computer model of an interconnected transmission network under a specific set of anticipated operating conditions/scenarios. Typically performed well before the system approaches that operational state.

Use of Transfer Capability:

- It can be used as an indicator of relative system security.
- It is useful for comparing the relative merits of planned transmission improvements.
- It provides an indication of the amount of inexpensive power likely to be available to generation deficient or high-cost regions.
- It facilitate energy markets by providing a quantitative basis for assessing transmission reservations.

Transfer Capability: Key Factors

Key Influencing Factors:

Projected Customer Demand:

- Base case demand levels should be appropriate to the system conditions.
- Demand levels may (ideally should be) be representative of peak, off-peak, shoulder, or light demand conditions.
- It requires details load forecasting / load growth projection study.

[http://www.cea.nic.in/reports/annual/lgbr/lgbr-2016.pdf]

Generation Dispatch:

- Utility and non-utility generators should be realistically dispatched for the system conditions being simulated.
- Merit order dispatch should be considered.

Transfer Capability: Key Factors

System Configuration:

- Base case configuration of the interconnected systems should include any generation and transmission outages that are expected which may modify the system topology.

Base Scheduled Transfers:

- The scheduled electric power transfers that should be modeled are those that are generally considered to be representative of the base system conditions being analyzed and which are agreed upon by the parties involved.
- Since the long-term and medium-term open access contracts are allowed in India, they should be adequately added in the base case transfers.

Transfer Capability: Key Factors

System Contingencies:

- A sufficient number of contingencies should be screened.
- They should be consistent with individual electric system, sub-regional, and regional planning criteria, to ensure that the facility outage most restrictive to the transfer being studied is identified and analyzed.
- In some instances credible multiple contingencies must be studied where deemed to be appropriate.

Importance of Transfer Capability: Security

Power System Security

- Transfer capability computations are useful for evaluating the ability of the interconnected system to remain secure following generation and transmission outages.
- Determining the adequacy of the transmission system in allowing external generation to replace internal generation is a typical application for transfer capability computations
- When a transfer capability for a feasible transfer is determined based on the energy schedules, the transfer capability represents a security margin. The distance between the present state and a state violating a security criteria is the amount of the transfer that initiates a security violation.

Importance of Transfer Capability: Markets

Electricity Markets

For many decades, vertically integrated electric utilities monopolized the way they controlled, sold and distributed electricity to customers in their service territories. In order to end this monopoly and introduce competition, vertically integrated utilities were required to unbundle their retail services into generation, transmission, and distribution.

- Bilateral Markets
- Pooled Markets
- Hybrid Markets

Determination of Transfer Capability

Step 1:

- Establish a secure, solved base case adequately representing the system operational state.

Step 2:

- Specify a transfer including source and sink assumptions.

Step 3:

- Specify the binding security limits/constraints (thermal, voltage magnitude, voltage collapse and any other operating constraint).

Step 4:

- Perform the transfer analysis by increasing source generation and decreasing the sink generation/ increasing the sink load, with contingencies applied.

Determination of Transfer Capability: Steps

- **Step 1, base case:**

Base case is a computer model of existing or projected power system conditions for a specific point in time to which the transfer is applied. The base cases include both **steady state** and **dynamic data**, and contain very large amounts of data necessary to model power system behavior. The base case is assumed to be an operating condition in which all quantities such as line flows and bus voltage magnitudes lie within their **operating limits**.

- **Step 2, specify the transfer:**

It requires to define a bus/area/region as **source** and another bus/area/region as **sink**. For example, a point to point transfer from bus A to bus B is specified by increasing power at bus A and reducing power at bus B. In this case bus A is called a source of power and bus B is called a sink of power.

Determination of Transfer Capability: Steps

- **Step 3, security limits:**

Usually Three types of security limits are used:

- Thermal Stability Limit.
  - ✓ Rating A (Summer), Rating B (Winter) and Rating C (Emergency)
- Voltage Security (Magnitude) Limit.
  - ✓ ± 5% for pre-contingency and ± 10% for post-contingency
- Voltage Stability (Collapse) Limit.
  - ✓ 5% for single contingency and 2.5% for credible multiple contingency

- **Step 4, perform the transfer analysis:**

Increase generation in one area and decrease generation/increase native load in another area. Apply the contingencies.

- Define Merit Order Dispatch.
- Enable/disable controls (transformer tap change) and model Special Protection Scheme (SPS).

Powertech

System Operating Limit (SOL)

SOL is defined as the MW value that **satisfies** the most limiting of the prescribed planning criteria for a specified system configuration to ensure operation within acceptable reliability criteria. SOLs are based upon certain planning criteria. These include, but are not limited to:

- Facility ratings (applicable pre- and post-contingency equipment or facility ratings).
- System voltage limits (applicable pre- and post-contingency state).
- Voltage stability limits.
- Transient stability limits.

SOL: Example

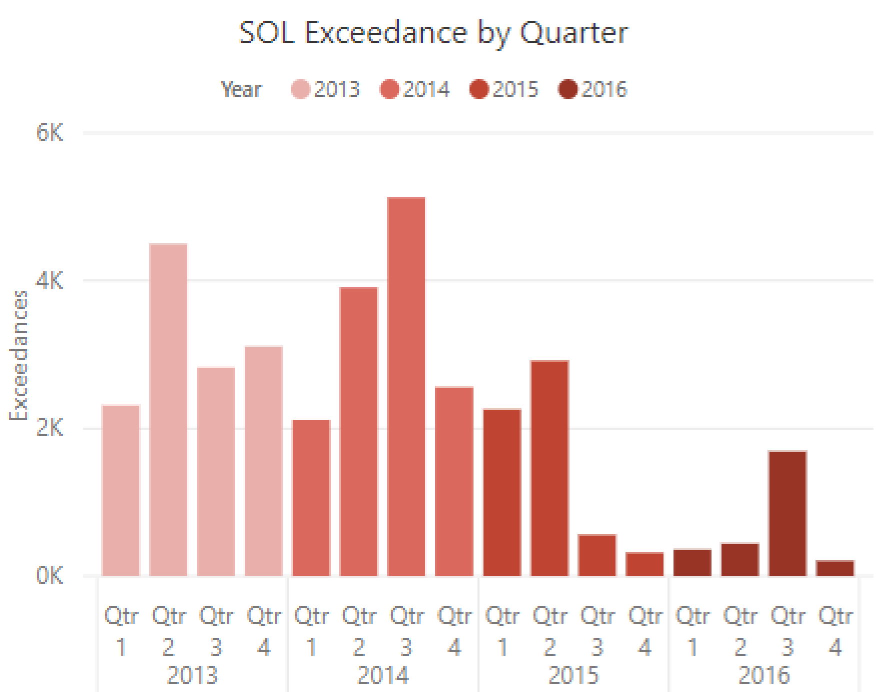
Example:

- If an area of the Bulk Electric System (BES) is at no risk of encroaching upon stability or voltage limitations in the pre- or post-Contingency state, and the most restrictive limitations in that area are pre- or post-Contingency exceedance of Facility Ratings, then the Thermal Facility Ratings in that area are the most limiting SOLs. Conversely, if an area is not at risk of instability and no Facilities are approaching their thermal Facility Ratings, but the area is prone to pre- or post-Contingency low voltage conditions, then the System Voltage Limits in that area are the most limiting SOLs.
- When SOL is associated with one or more paths, that is called path SOL. Sometimes it is also called path rating as used by Western Electricity Coordinating Council (WECC).

SOL: Exceedance Example

SOL Exceedance:

In many cases actual flows on paths exceed the calculated SOL.



SOL Exceedance: WECC Paths

Most exceedances are short in duration and low in magnitude. 83% in 2016 lasted less than one minute and were less than 50 MW above SOL.

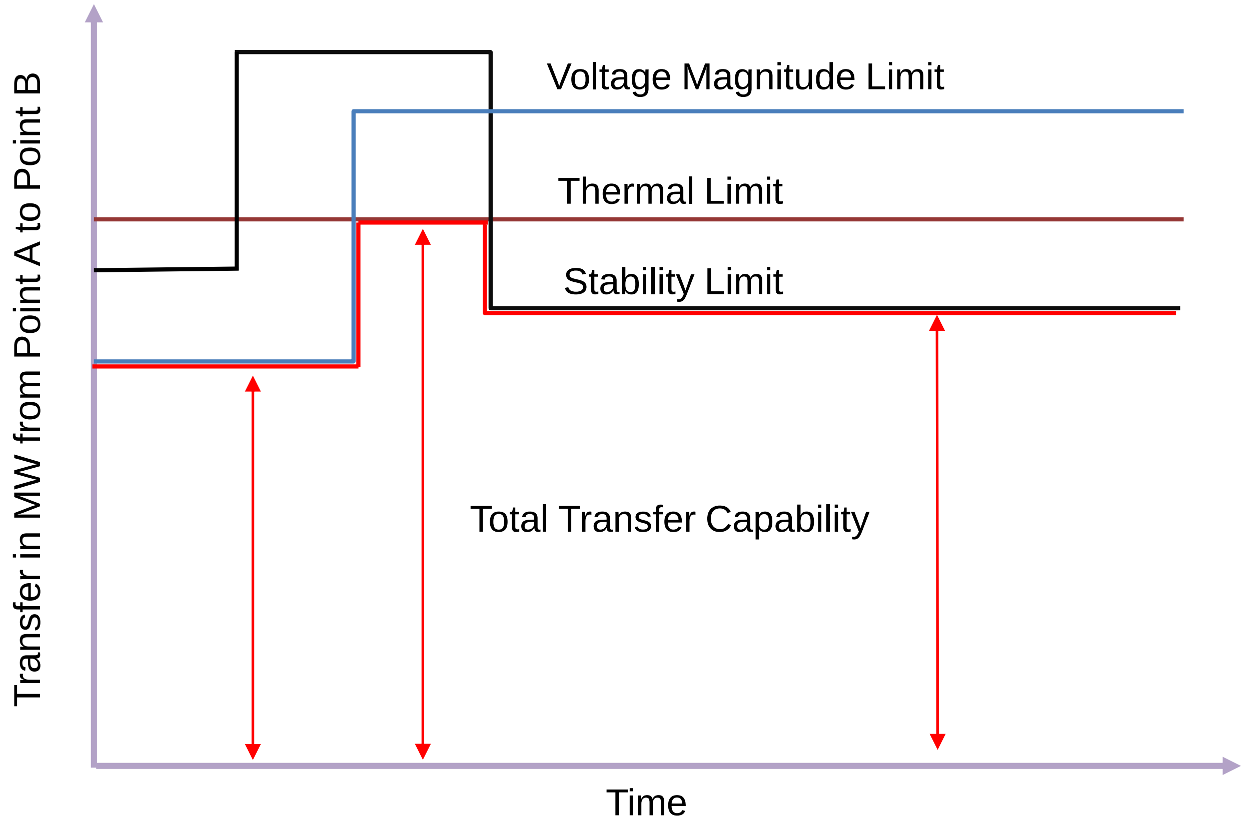
The decrease in exceedances over the last two years has been primarily driven by infrastructure improvements and load composition changes in the Pacific Northwest and Canada.

Total Transfer Capability (TTC)

TTC can be defined as the amount of electric power that can be transferred **reliably** over the inter-control area transmission system under a given set of operating conditions. Determination of TTC depends on

- System conditions.
- Critical contingencies.
- System limits .
- Parallel path flows (nomogram).
- Non-simultaneous and simultaneous transfers.

TTC: Illustration



Powertech

TTC: Required Conditions

Required Conditions:

- All facility loadings are within normal ratings and all voltages are within normal limits.
- System remains stable following a disturbance that results in the loss of any single electric system element, such as a transmission line, transformer, or generating unit.
- In post-contingency period all transmission facility loadings are within emergency ratings and all voltages are within emergency limits, before any post-contingency operator-initiated system adjustments are implemented.
- If credible multiple contingencies cause more restrictive transfer limits then the more restrictive reliability criteria or guides must be observed.

Transmission Reliability Margin (TRM)

- The TRM is defined as the amount of transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure.
- TRM provides a reserve of transfer capability that ensures the reliability of interconnected transmission network.
- All transmission system users benefit from the preservation of TRM by transmission providers.

TRM: Uncertainties

***Aggregate Load Forecast*:**

- The inability to precisely predict a future load level and the subsequent loading experienced on transmission system elements requires a reasonable quantity of transmission capacity to remain "uncommitted."
- This "uncommitted" transmission resource, when actually needed in real time, benefits the entire community to ensure that the reliability of the entire interconnection is maintained.

***Load Distribution*:**

- Maintenance of a reasonable quantity of "uncommitted" transmission capacity will help to ensure that the reliability of the entire interconnection is maintained.

TRM: Uncertainties

Uncertainty in System Topology:

- Most TTC calculations performed are based upon the most critical single contingency and do not account for the base system condition including some level of facility outages.

Impacts of Parallel Path (Loop Flow):

- These parallel path flows are the result of transmission service transactions that are not explicitly scheduled on the transmission system of a particular transmission provider.
- Therefore, maintenance of a reasonable quantity of “uncommitted” transmission capacity will help to ensure that the reliability of the entire interconnection is maintained.
- Proper coordination of basic system data between transmission providers should minimize the magnitude of this component.

TRM: Uncertainties

Interactions of Simultaneous Paths:

- Transmission paths may interact and not be capable of operation at each path's full transfer capability.
- In the context of Indian power system, this is a persistent issue when power flows from WR and ER to NR. Since this can be addressed through a proper allocation of resources and fully considered in TTC calculation, it should be exempted from TRM.

Variations in Generation Dispatch:

- The generation dispatch will vary for reasons such as number of units having load-following capability, generation availability and production costs within a generating plant.
- Maintenance of a margin helps account for the impacts of these variations upon the transmission system.

TRM: Uncertainties

***Short-term Operator Response/Operating Reserves*:**

- Following a contingency, system operators take immediate actions to maintain the reliability of the transmission system.
- Transmission capacity must remain available to allow for operational flexibility immediately following such a contingency.
- In the case of emergency, this TRM component can be used to restore and maintain the grid stability. However, it should not be a permanent arrangement to meet the reliability requirements.

TRM: Uncertainties

***Reserve Sharing Requirements*:**

- Although sufficient generations are always scheduled to meet the demand, unplanned events like sudden, unexpected increase in demand, generation loss, and loss of transmission element that results in a restrictive operating limit which makes supply unavailable.
- In order to address such situation, there should be enough standby resources available in the form of operating reserve.

***Inertial Response and Frequency Bias*:**

- This component is usually used when a system employs AGC. Without AGC the capacity reserved under this category may never be utilized.

TRM: Determination

***TRM Applied by Rating Reduction*:**

- For systems in which the distribution of uncertainty among all of its facilities is relatively uniform, a TRM applied to all the system facilities of a transmission provider may be appropriate.
- The TRM is applied against the facility ratings themselves and is measured as a percentage reduction of facility ratings.
- The rating reduction is typically 2-5% and may increase/decrease over an extended time horizon.

Example:

Calculate at a given rating, $ATC_A = TTC_A$ assuming TRM = 0;

Then create another base case with reduced facility ratings.

Recalculate, $ATC_B = TTC_B$ assuming TRM = 0

$$TRM = ATC_A - ATC_B$$

TRM: Determination

TRM Applied by Interface:

- In systems where uncertain contributions can be associated with specific interfaces or flowgates, a TRM applied to specific critical interfaces or flowgates may be appropriate.
- Systems that apply TRM in this manner typically would be able to quantify the uncertainty associated with TRM components through the use of historical transmission loading analysis.
- The TRM applied in this manner is relatively constant but may change based on the actual system operating experience.

Capacity Benefit Margin (CBM)

CBM is defined as the amount of firm transmission transfer capability preserved for Load Serving Entities (LSEs) on the host transmission system where their load is located, to enable access to generation from interconnected systems to meet generation reliability requirements

- The transmission capacity preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
- The direct beneficiaries of CBM can be identified.
- These beneficiaries are the LSEs that are network customers (including native load) of a host transmission provider.
- CBM may be sold on a non-firm basis.

Available Transfer Capability (ATC)

ATC is a measure of the transfer capability remaining in a physical transmission network for further commercial activity over and above already committed uses.

Mathematically,

$$ATC = TTC - TRM - CBM - ETC$$

ETC: Existing Transmission Commitments

- The ATC between two areas provides an indication of the amount of additional electric power that can be transferred from one area to another for a specific time frame for a specific set of conditions.
- ATC can be a very dynamic quantity because it is a function of variable and interdependent parameters.

Existing Transmission Commitments (ETC)

ETC can be power flows modeled in the base system conditions, discrete values accounted for in the ATC or AFC calculation, or both. The ETC value may be a sum of the actual reservation values, an "expected to be used" value, an "effect the value has on this flowgate or path" value, or a combination thereof

$$ETC = NITS + GF + PTP + ROR + OS$$

- NITS is the capacity set aside for Network Integration Transmission Service
- GF is the capacity set aside for Grandfathered Transmission Service and contracts which were executed prior to the effective date of a TSP's Open Access Transmission Tariff
- PTP is the capacity reserved for confirmed Point-to-Point Transmission Service.
- ROR is the capacity reserved for rollover rights
- OS is the capacity reserved for any other service

TTC Calculation Methodologies

There are three methodologies used by utilities in North America and Europe:

- Area Interchange Methodology
- Rated System Path Methodology
- Flowgate Methodology

TTC: Area Interchange

Area Interchange Methodology

- Determination of TTC in the Area Interchange method is based on predicting the system response to power flowing from one area of the system to the other. This prediction is made by stressing the system with appropriate transfers under critical contingencies to determine the response of the transmission system.
- Adopted by very few utilities in North America, Florida Power and Light (FPL) is one of them.

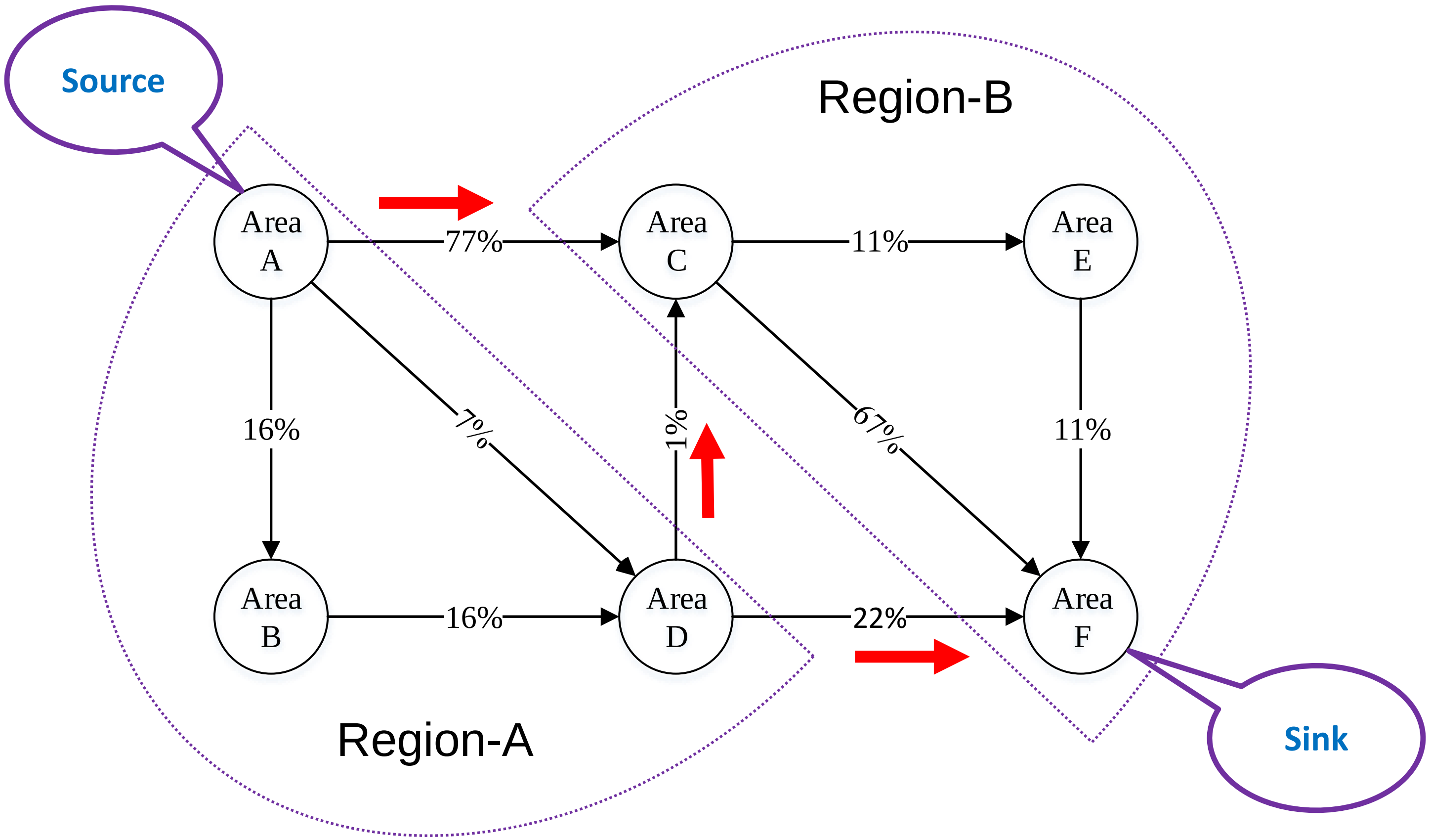
TTC: Area Interchange

- In the Area Interchange Methodology, the transaction is simulated with a specific source and sink. The path flow is increased until a transmission limit is reached which is termed as TTC of that path for the specified source/sink interchange.
- The TTC determined by this method is dependent on a number of variables, such as base case dispatch and system demand, other transactions already in place or assumed, source and sink locations, and the generators that are scheduled for the transaction, etc.

TTC: Area Interchange

- For each isolated pair or a single transaction, the ATC determination using this method is not very complicated. This calculation process becomes complicated when a TSP must determine ATCs for multiple source/sink pairs upon request or as required by regulations or reliability standards to post these ATCs ahead of time.
- Further, ATC reserved under this method is made on a “Contract Path” basis. That is, an intended specific source/sink interchange may reserve ATCs of its choice among any one of the transmission networks for so long as the network(s) chosen forms a contiguous path from source to the sink.

TTC: Area Interchange - Example



Lets Area-A exports 1000 MW to Area-F
A-C Flow = 770 MW
A-B Flow = 160 MW and A-D = 70 MW

Powertech

NERC Standards for Area Interchange Methodology

- MOD-028-1 is for the development and documentation of transfer capability calculations for registered entities using the Area Interchange Methodology.
- ATC = TTC – ETC – CBM – TRM + Postbacks + Counterflows

Postbacks: changes to ATC due to a change in the use of Transmission Service for that period

*Counterflows: ad*justments to ATC as determined by the Transmission Service Provider

TTC: Rated System Path

Rated System Path Methodology

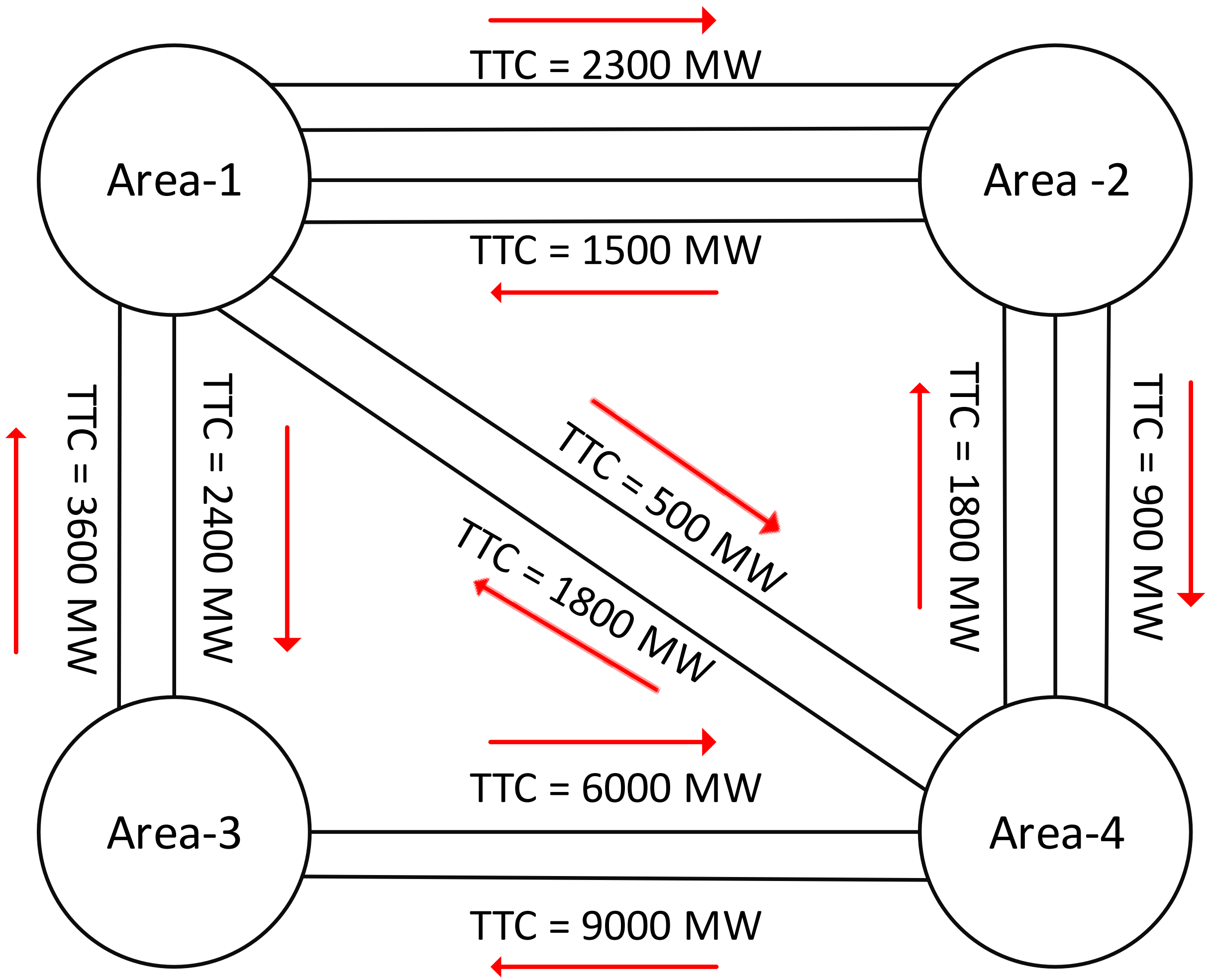
- The RSP method for ATC calculation is typically used for transmission systems that are characterized by sparse networks with customer demand and generation centers distant from one another.
- Generally, in this approach transmission paths between areas of the network are identified and appropriate system constraints determined. ATC is computed for these identified paths and interconnections between TSPs.
- This method has been used widely in the western part of North America. BC Hydro, NYISO, ISO-NE and many other TSOs/TOPs in the eastern part of North America also use this methodology to calculate their TTC and ATC.

TTC: Rated System Path

- In the Rated System Path methodology, TTC is calculated for a specific set of transmission facilities, commonly referred as a path, and then TTC is adjusted to establish the ATC for those paths.
- Reserved transmission services sometimes known as ETC is subtracted from the posted ATC while reservations that will create a counter-flow on the Path are added to the ATC.
- This method is feasible for a system where there exist well-defined interfaces between areas or regions, or there is a good control of the flows on the paths via High Voltage Direct Current (HVDC) links or phase angle regulators to control or mitigate the adverse impact of parallel flows.

Powertech

TTC: Rated System Path - Example



$$TTC_{m \to n} \neq TTC_{n \to m}$$

Powertech

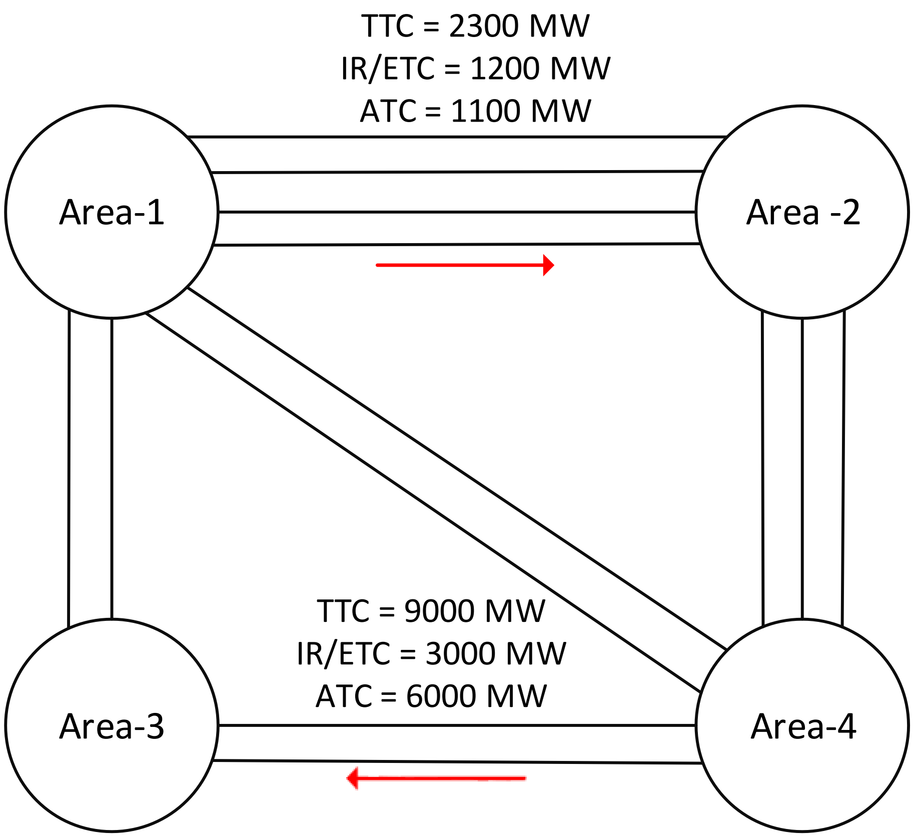
TTC: Rated System Path - Example

Case-1:

It is assumed that TRM = 0 and CBM = 0

ATC=TTC-IR/ETC

Where, IR is Initial Line Reservation



TTC: Rated System Path - Example

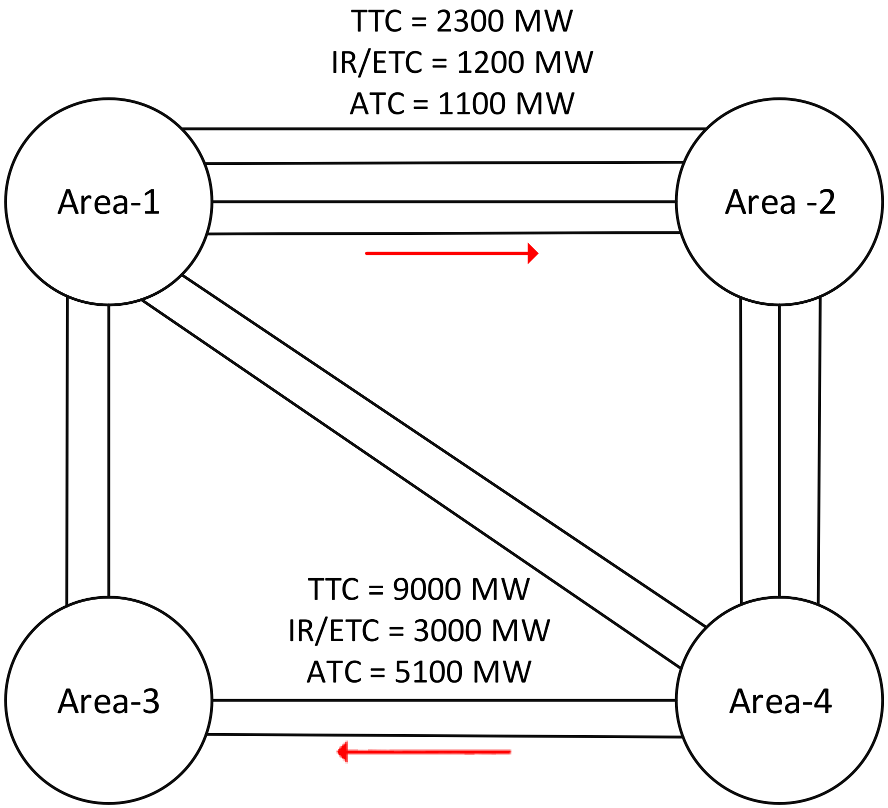
Case-2:

900 MW non-recallable transmission service is acquired from Area-4 to Area-3

It is assumed that TRM = 0 and CBM = 0

ATC=TTC-IR/ETC =9000-3000-900=5100 MW

Where, IR is Initial Line Reservation



Powertech

NERC Standards for Rated System Path Methodology

- MOD-029-1a is for the development and documentation of transfer capability calculations for registered entities using the Rated System Path Methodology.
- ATC = TTC – ETC – CBM – TRM + Postbacks + Counterflows

Postbacks: changes to ATC due to a change in the use of Transmission Service for that period

*Counterflows: ad*justments to ATC as determined by the Transmission Service Provider

TTC: Flowgate

Flowgate Methodology

- The Flowgate Methodology uses a flow-based approach to calculate ATC based on a predetermined set of constraints—a subset of monitored and contingent elements called flowgates.
- AFC is the amount of unused transfer capability on a flowgate after accounting for base case conditions represented by solved base case flows and applying the impacts of non base case commitments and flowgate specific margins.
- PJM, SPP, and TVA are the major ones who employ the flowgate methodology for the calculation of the AFC which is then converted to ATC using the algorithms specified in the MOD-030-2 standard.

TTC: Flowgate

- The “flowgates” are defined as the inter zonal links in the transmission system, with flow limits and capacity rights defined on these Links
- The most important feature is that flowgate rights can be defined independent of the pattern of power flows.
- A flowgate involves a monitored element and a contingent element.
- The flowgate limit is determined when either of the element/s long-time rating is reached, or when the monitored-element’s applicable short-time rating is expected to be reached based on the contingent-element being removed from service.

TTC: Flowgate

- TTCs for equipment-limited flowgates change as a function of pre-contingency flows on the flowgate elements and the ambient conditions. However, TTCs for voltage or stability limited flowgates usually do not change significantly, making the complexity of its TTC determination process somewhere between the Area Interchange and Rated System Path.
- Since the transmission service, or reservation of ATC, is managed on a per flowgate basis, each reservation must be assessed using the intended transaction's Transfer Distribution Factor (TDF) on the flowgate, as well as the impacts on the ATCs on all flowgates. For the flowgate method reservations are required on the identified flowgates.
- This flow-based reservation process addresses the parallel issues, but it also adds computational complexity.

NERC Standards for Flowgate Methodology

- MOD-030-2 is for the development and documentation of transfer capability calculations for registered entities using the Area Interchange Methodology.
- AFC = TFC –EFC –CBM–TRM + Postbacks+ Counterflows
- ATC = Minimum {AFC1 / Transfer Response Factor, …AFCn / Transfer Response Factor}

Where n is the number of limiting flowgates for a specific POD and POR pair.

Postbacks: changes to ATC due to a change in the use of Transmission Service for that period

*Counterflows: ad*justments to ATC as determined by the Transmission Service Provider

Transfer Capability Calculation Methodologies Presently Used by POSOCO and CTU

Organisational Overview: CEA

Central Electricity Authority (CEA)

- Advises the Central Government on the matters relating to the national electricity policy, formulate short-term and perspective plans for development of the electricity system and coordinate the activities of the planning agencies for the optimal utilization of resources to sub serve the interests of the national economy and to provide reliable and affordable electricity to all consumers.
- Specifies the technical standards for construction of electrical plants, transmission lines and connectivity to the grid.
- Specifies the safety requirements for construction, operation and maintenance of electrical plants and electric lines.

Organisational Overview: CEA

Central Electricity Authority (CEA)

- Specifies the Grid Standards for operation and maintenance of transmission lines.
- Specifies the conditions for installation of meters for transmission and supply of electricity.
- Promotes and assist in the timely completion of schemes and projects for improving and augmenting the electricity system.
- Promotes measures for advancing the skill of persons engaged in the electricity industry.

Organisational Overview: CTU

Central Transmission Utility (CTU)

- Provides the infrastructure for the transmission of electricity through Inter State Transmission System (ISTS).
- Executes the planning and co-ordination functions relating to ISTS with State Transmission Utilities (STUs), central government, state governments, generating companies, Regional Power Committees (RPCs), authority, licensees and any other entities notified by the central government in this behalf.
- Ensures the development of an efficient, coordinated and economical system of inter-state transmission lines for smooth flow of electricity from generating stations to load centers.

Organisational Overview: CTU

Central Transmission Utility (CTU)

- Provides non-discriminatory open access to its transmission system for use by any licensee or generating company on payment of the transmission charges; or any consumer as and when such open access is provided by the State Commission, on payment of the transmission charges and a surcharge thereon, as may be specified by the Central Commission.

Organisational Overview: POSOCO

Power System Operation Corporation Limited (POSOCO)

- Supervises and controls all aspects concerning operations and manpower requirements of RLDCs and NLDC. All the employees and executives working with RLDCs and NLDC will be from the cadre of POSOCO.
- Ensures planning and implementation of infrastructure required for smooth operation and development of NLDC and RLDCs.
- Coordinates the functioning of NLDC and all the RLDCs.
- Advises and assists state level Load Dispatch Centers, including specialized training, etc.
- Performs any other function entrusted to it by the Ministry of Power.

TTC/ATC Calculation Methodology: POSOCO

- POSOCO calculates and publishes the TTC/ATC values in 0-3 months ahead.
- There are 5 RLDCs which calculate the TTC/ATC for the paths connecting their regional grid to another region(s).
- NLDC as the central organization collects TTC/ATC information from all RLDCs, verifies and reassesses them.
- Each RLDC completes all calculations by the 26th day of each month for 3 months ahead cases and submits the results to NLDC.
- NLDC verifies and publishes the final values by the 28th day of the same month.

TTC/ATC Calculation Methodology: POSOCO

Base Case Development:

- NLDC suggests RLDC about the inter-regional flows based on long-term and medium-term contracts.
- Each RLDC updates its own region's load generation balance & network topology and sends updated cases to NLDC.
- NLDC then prepares the all-India base case which contains updated load generation balance of all the regions.
- Any mismatch in all-India base case is generally adjusted by scaling load to maintain swing bus generation equal to dispatch specified.

TTC/ATC Calculation Methodology: POSOCO

CEA Guidelines on Base Case Development:

- All generating units greater than 50 MW and connected at 132 kV and above are modeled.
- Transmission network including 132 kV and above is modeled .
- Loads are generally lumped at 220 kV or 132 kV.

Other Guidelines on Base Case Development:

- **Network topology:** This shall be as per network data obtained from CTU and STUs. New transmission elements shall be considered only after the date of commissioning of that asset.
- **Unit availability:** This shall be as per the maintenance schedule finalized by RPC. The new generating units expected to be available during the assessment period shall be considered only after commissioning of the new units.

TTC/ATC Calculation Methodology: POSOCO

Other Guidelines on Base Case Development :

- **Coal-fired thermal despatch:** This shall be as per the anticipated generation of the thermal generating units coming online after deducting their auxiliary consumption as per the norms specified by Central Commission and allowing partial outage based on the experience of system operator of the power plant.
- **Gas/ nuclear despatch:** This shall be as per past trend of Plant Load Factor available with Central Electricity Authority (CEA) or as per past trend available at SLDCs/ RLDCs.
- **Hydro despatch:** This shall be as per the past trend available at RLDCs/ SLDCs. The day corresponding to the median value of daily consumption of the same month last year would be chosen. The current inflow pattern shall also be considered.

TTC/ATC Calculation Methodology: POSOCO

Other Guidelines on Base Case Development:

- **State MW demand:** As per the anticipated load provided by SLDCs or Load Generation Balance Report (LGBR) prepared by CEA or past trend available at RLDCs/ NLDC.
- **State MVAr demand:** As per the anticipated power factor provided by SLDCs. In the absence of data from SLDCs, the load power factor at 220 kV or 132 kV voltage levels shall be taken as 0.95 (lagging) during peak load condition and 0.98 (lagging) during light load condition except areas feeding predominantly agricultural loads as given in the CEA's Manual on Transmission Planning Criteria.

TTC/ATC Calculation Methodology: POSOCO

Credible Contingencies Selection:

- Outage of single transmission element (i.e., N-1 contingency) in the transmission corridor or connected system whose TTC is being determined as defined in Indian Electricity Grid Code (IEGC), including outage of one pole of each bi-polar dc link.
- An outage of the single largest unit in the importing control area station.

TTC/ATC Calculation Methodology: POSOCO

Security Criteria:

- Violation of grid voltage operating range.
- Violation of emergency thermal limit (110% of the normal thermal rating) under N-1 contingency.
- Transient stability under N-1 contingency of a permanent 3-phase fault on a 765 kV, 400 kV, 220 kV, or 132 kV line close to the bus.
- Transient stability under permanent outage of one pole of a bi-polar dc link.
- Transient stability under N-1-1 contingency of a temporary SLG fault on a 765 kV line close to the bus or a permanent SLG fault on a 400 kV line close to the bus.
- Angular difference of 30 degrees between adjacent buses under N-1 contingency.

TTC/ATC Calculation Methodology: POSOCO

TRM Calculation:

In compliance with the existing CEA criteria and CERC regulation NLDC and each RLDC calculate the TRM for their ATC paths. The current regulation suggests that the TRM should be one of the two values as mentioned below:

- Two percent (2%) of the total anticipated peak demand met in MW of the control area/group (to account for forecasting uncertainties).
- The size of the largest generating unit in the control area/ group of control area/ region.

TTC/ATC Calculation Methodology: POSOCO

- Three categories of transmission access available in India:

CTU Approves:

- Long Term Access (LTA): > 7 years
- Medium Term Open Access (MTOA): 3 months-5 years,

POSOCO Approves:

- Short Term Open Access (STOA): up-to 1 month, 3 months in advance.

Margin available for STOA = TTC – TRM – LTA – MTOA

ATC=TTC-TRM

- In some paths, counter flows are considered during the ATC calculation. The assumption used by POSOCO is "Fifty percent (50%) counter flow benefit on account of LTA/MTOA transactions in the reverse direction would be considered for bilateral (advanced & first come first serve) transactions."

TTC/ATC Calculation Methodology: CTU

- CTU as the central planner calculates the TTC/ATC using the long-term planning cases.
- The calculation methodology used by CTU is quite similar to the methodology followed by POSOCO with few changes. However, the development procedure for base cases is quite different in the case of CTU as it deals with long-term planning process.
- The margin available for MTOA is calculated as follows:

$$\text{Margin available for MTOA} = \text{TTC} - \text{TRM} - \text{LTA}$$

$$\text{ATC}=\text{TTC}-\text{TRM}$$

Transfer Capability Calculation Methodologies Used by Various TSPs /TOPs /ISOs in the World

NERC Standards/Guidelines

- MOD-001-1a is the umbrella standard that contains the generic requirements applicable to all methods of determining ATC.

  Each Transmission Service Provider shall prepare and keep current an Available Transfer Capability Implementation Document (ATCID)

- MOD-004-1 provides for the consistent calculation, verification, preservation, and use of Capacity Benefit Margin (CBM).

  The Transmission Service Provider that maintains CBM shall prepare and keep current a "Capacity Benefit Margin Implementation Document" (CBMID)

- MOD-008-1 provides for the consistent calculation, verification, preservation, and use of Transmission Reliability Margin (TRM).

  Each Transmission Operator shall prepare and keep current a TRM Implementation Document (TRMID)

NERC Standards/Guidelines

- MOD-028-1 provides for the development and documentation of transfer capability calculations for registered entities using the Area Interchange Methodology.

- MOD-029-1a provides for the development and documentation of transfer capability calculations for registered entities using the Rated System Path (RSP) Methodology.

- MOD-030-2 provides for the development and documentation of transfer capability calculations for registered entities using the Flowgate Methodology.

BC Hydro, British Columbia, Canada

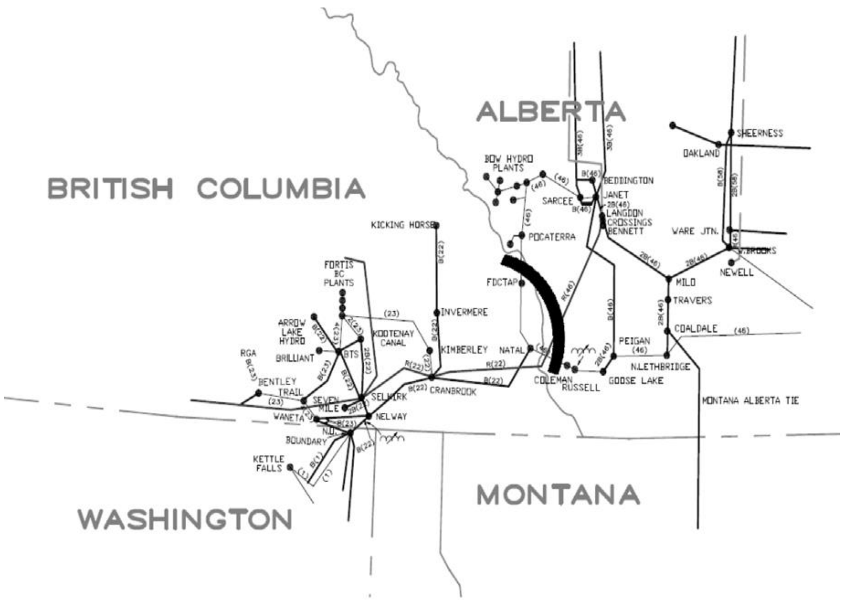
BC Hydro is a provincial Crown Corporation with a mandate to generate, purchase, distribute and sell electricity.

Features:

- There are six ATC paths (3 Forward and 3 Reverse) for which BC Hydro calculates the TTC and ATC which are carried out on hourly, daily, weekly and monthly basis.
- TTC on all ATC paths remain the same for both the planning and operation horizons unless there are changes to the transmission system topology either due to planned or unplanned outages.
- BC Hydro uses Rated System Path methodology as described in the current version of NERC standard MOD-029-1a to calculate TTC and ATC for various ATC paths

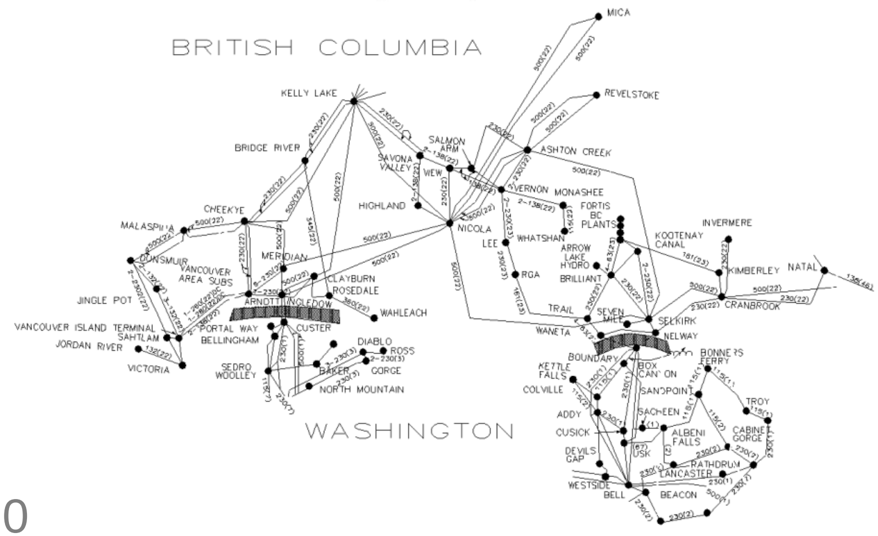
Powertech

BC Hydro WECC Paths



Path-1:

- BCH-AESO: 1200 MW
- AESO-BCH: 1000 MW



Path-3:

- BCH-BPA (N-S): 3150 MW
- BPA-BCH (S-N): 3000 MW

Powertech

BC Hydro: TRM

Uncertainties Considered in TRM:

- Aggregate load forecast.
- Variations in generation dispatch.
- Inertial response and frequency bias.
- Forecast uncertainty in transmission system topology.

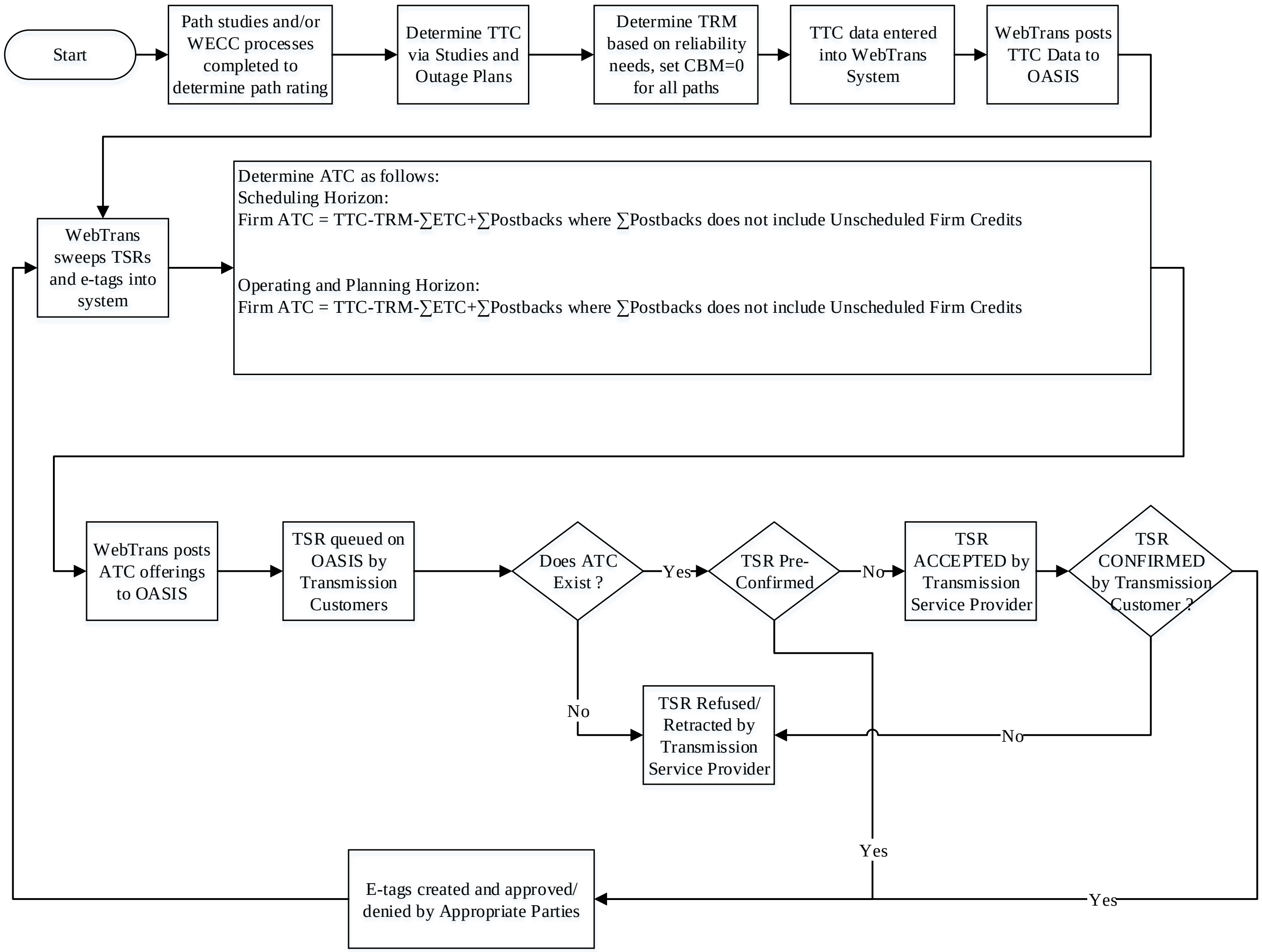
BC Hydro normally uses **50 MW TRM** for the US Intertie (both directions), and **65 MW TRM** for the Alberta Intertie (both directions). BC Hydro no longer makes any allowance for CBM over its interties and always sets **CBM to zero** while calculating the ATC

ATC Calculation:

- $ATC_F = TTC – ETC_F – CBM – TRM + Postbacks_F + Counterflows_F$
- $ATC_{NF} = TTC – ETC_F – ETC_{NF} – CBMs – TRM_U + Postbacks_{NF} + Counterflows_{NF}$

BC Hydro: ATC Process

ATC Calculation Process Flowchart



Powertech

California ISO (CISO), California, USA

- California Independent System Operator (CISO) is one of nine ISOs in North America.
- TTC calculation for all major inter-area paths (mostly 500 kV circuits) is overseen by the California Operating Studies Subcommittee (OSS), which provides detailed criteria and methodology in accordance with the MOD-029-1a.
- CISO, in collaboration with owners of paths, has selected the Rated System Path methodology for the TTC/ATC calculation for various ATC paths.
- CISO uses the following contingency criteria:
  - All pre- and Post-contingency circuit flows shall be at or below their normal ratings and bus voltages shall be within a pre-determined operating range.

CISO: TRM, CBM, and ATC

- CISO calculates TRM at intertie points to account for the following NERC-approved components of uncertainty in compliance with MOD-008-1
  - Forecast uncertainty in transmission system topology, including forced or unplanned outages or maintenance outages.
  - Allowances for parallel path (loop flow) impacts, including unscheduled loop flow.
  - Allowances for simultaneous path interactions.
- CISO does not set any CBM i.e., CBM=0
- ATC = TTC – TRM + Counterflows

Bonneville Power Administration (BPA), Washington, USA

- Bonneville Power Administration (BPA) is a federal nonprofit agency based in the Pacific Northwest.
- BPA’s service territory includes Idaho, Oregon, Washington, western Montana and small portions of eastern Montana, California, Nevada, Utah, and Wyoming.
- There are 16 ATC paths.
- BPA uses Rated System Path Methodology to calculate TTC/ATC.
- BPA does not calculate TRM on most of its paths except northern intertie.
- CBM is always set to zero on all paths.
- For northern intertie ATC path: ATCF = TTC – ETC – TRM
- For rest of the ATC paths: ATC = TTC – ETC

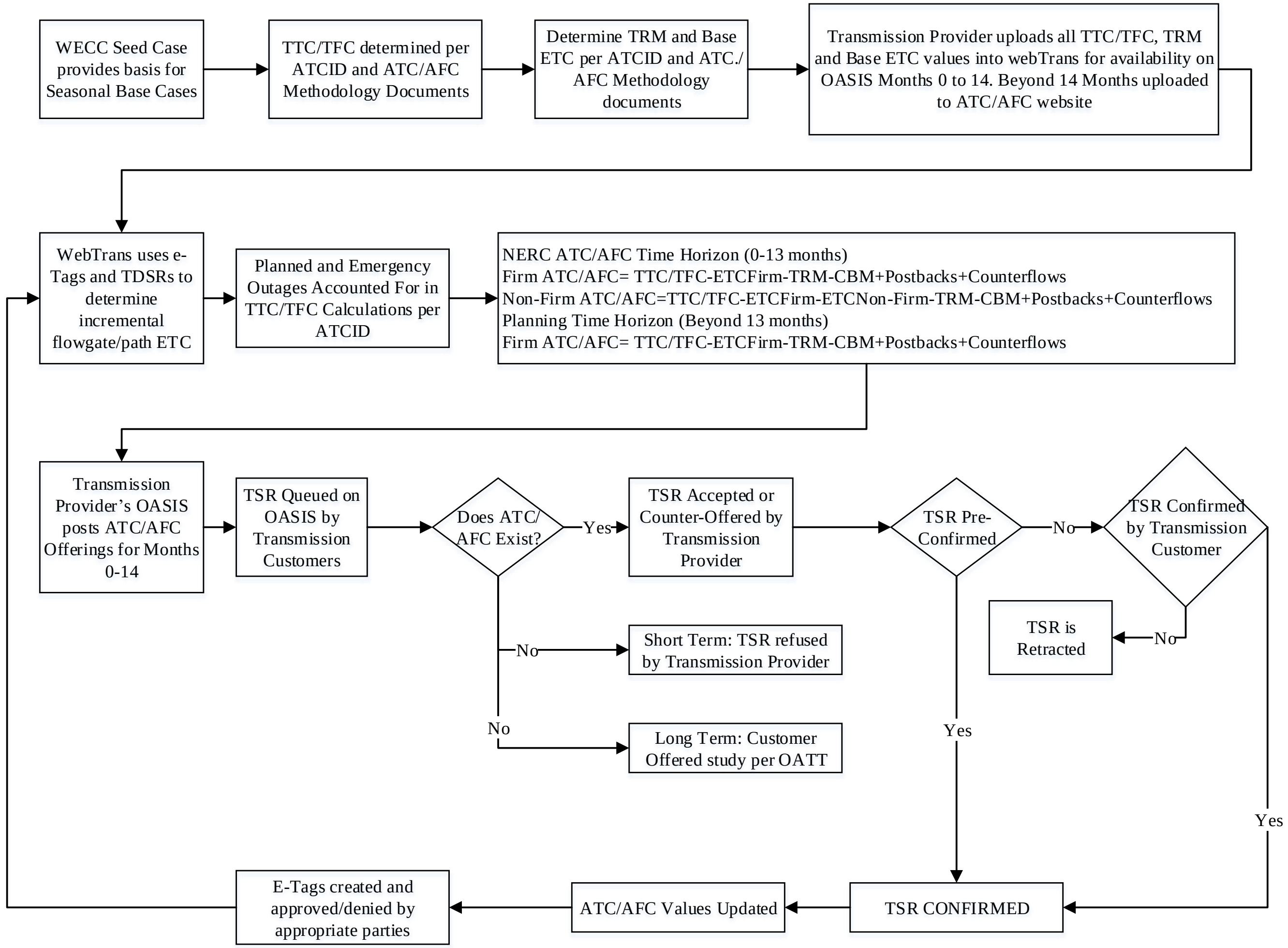
BPA: Base Case

BPA Base Case Development Guidelines:

- All system elements are modeled in their normal operating condition for the assumed initial condition.
- All phase shifting transformer are modeled in non-regulating mode, whereas, all generators above 20 MVA are included in the base case model.
- For each bus, season load forecasts are included in the model.
- Actual dates of energization/de-energization of generation and transmission facility are included in the operating base cases.
- All SPS or RAS that currently exist or are projected for implementation within the studied time horizon are modeled.
- Series compensations for each line are modeled.

BPA: ATC/AFC Process

BPA ATC/AFC Calculation Process Flow Chart



Powertech

Pennsylvania, Jersey, Maryland (PJM) Interconnection, USA

- Pennsylvania, Jersey, Maryland (PJM) interconnection is an RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.
- PJM uses the flowgate methodology for the ATC calculation. In this methodology, available flowgate capabilities are calculated and then translated to available transmission capability using the recommended algorithm.
- Some flowgates are modeled without contingencies known as Power Transfer Distribution Factor (PTDF) flowgates, whereas some are modeled with contingencies known as Outage Transfer Distribution Factor (OTDF) flowgates.

PJM: TRM

TRM Calculation:

- PJM considers three components of uncertainties to calculate the TRM
  - Aggregate load forecasting uncertainty.
  - Allowances for parallel path (loop flow) impacts.
  - Variations in generation dispatch.
- TRM is set to 2% of the flowgate rating for all PJM owned flowgates that are included in the AFC/ATC process for Firm/ Non-Firm ATC calculations.
- If TRM values for non-PJM flowgates are not provided by the coordination entities, then PJM applies a TRM of 2%.
- In some cases, TRM is also set to 5% of the flowgate rating.

PJM: AFC/ATC

AFC/ATC Calculation:

- The algorithms used for the AFC calculation are as follows:

  $AFC_F = TFC - ETC_{Fi} - CBM_i - TRM_i + Postbacks_{Fi} + Counterflows_{Fi}$

  $AFC_{NF} = TFC - ETC_{Fi} - ETC_{NFi} - CBMs_i - TRM_{Ui} + Postbacks_{NFi} + Counterflows_{NFi}$

- PJM uses the following algorithm for converting flowgate AFCs to ATCs for ATC paths:

  ATCp = Min (P)

  P = {PATC1, PATC2,…PATCn}

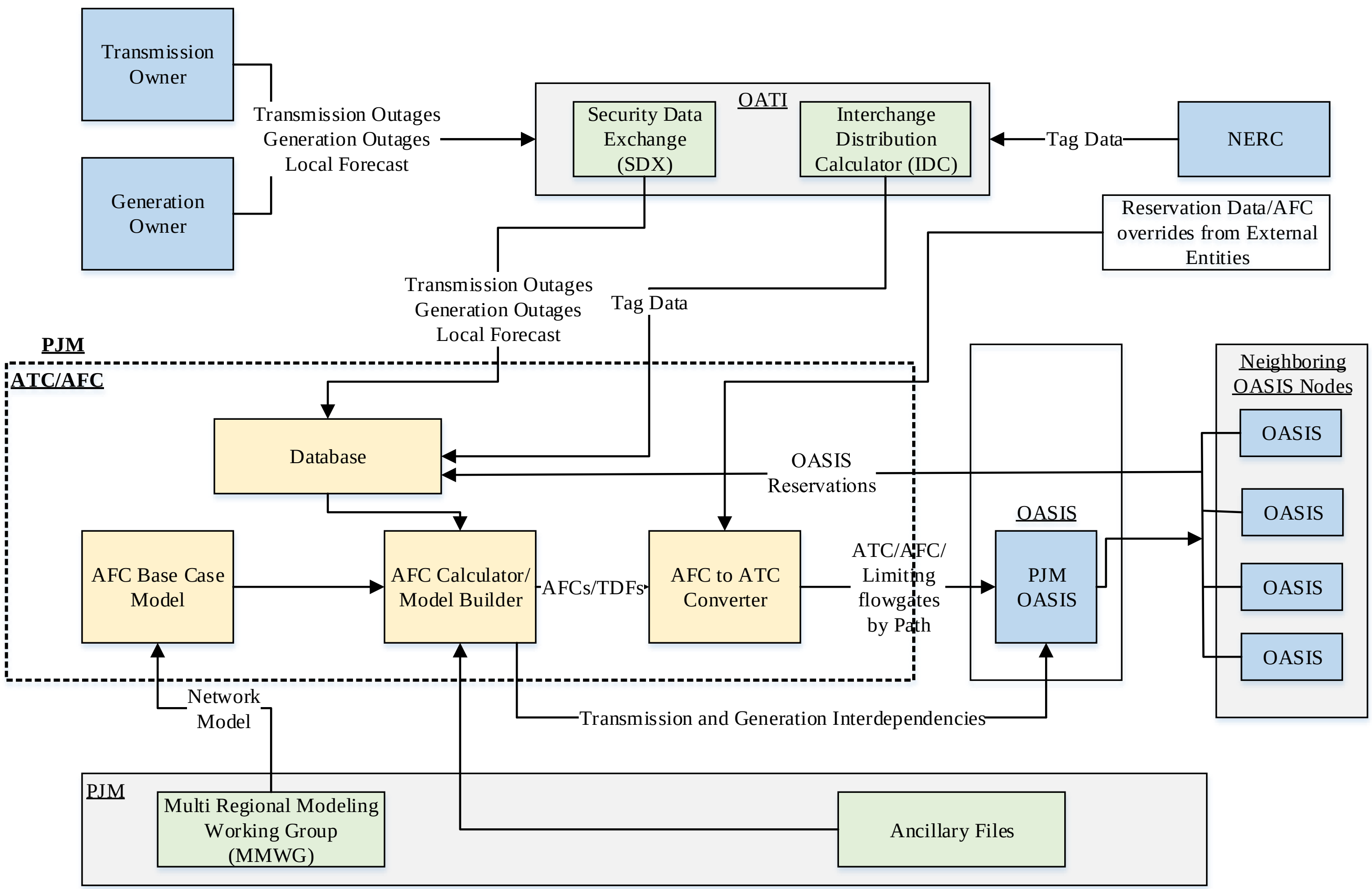
  PTCn = AFCn / DFnp

The subscript "p" refers to a particular path.

Powertech

PJM: AFC/ATC Process

PJM AFC/ATC Calculation Process Flow Chart



Powertech

Florida Power and Light (FPL), USA

- Florida Power & Light Company (FPL) is a Juno Beach Florida-based power utility serving roughly 4.7 million customers and 9 million people in Florida.
- FPL has elected to use the Area Interchange methodology to calculate ATC for all paths.
- FPL uses the base models derived from the current Florida Reliability Coordinating Council (FRCC) Transmission Working Group (TWG) seasonal models and represents the network topology for the entire FRCC region as well as the sub-region of the South East Reliability Council (SERC) region immediately adjacent to the FRCC. The remainder of the SERC is an equivalent representation in the models.

FPL: TRM, CBM, and ATC

TRM Calculation:

- FPL calculates the TRM considering two components of uncertainty: variations in generation dispatch (critical unit offline) and variation in generation pattern in the southern region.

CBM Calculation:

- FPL does not currently maintain any CBM. Therefore, CBM for Firm and Non-Firm ATC are set to zero.

ATC Calculation:

- FPL limits its TTC to the lower of the two limitations, the sum of its tie facility ratings with the other entity participating in the transfer or any contractual limitations including allocated share.
- ATC=TTC-TRM-ETC

Nordic TSO, Europe

- Nordic Power Market is a free electricity market that consists of five countries: Sweden, Denmark, Norway, Finland and Estonia.
- There is no specific methodology defined to calculate the TTC/NTC in Nordic Power System. However, calculation methods rely on ENTSO-E NTC procedure.
- In Europe TTC is known as the total transfer capacity which is defined as the maximum transmission of active power in accordance with the system security criteria which is permitted in transmission cross-sections between the subsystems/areas or individual installations.
- TTC is calculated considering the N-1 contingency criteria which is an expression of a level of system security entailing that a power system can handle the loss of any single component (production unit, line, transformer, bus bar, consumption etc.)

Nordic TSO: TRM and CBM

TRM calculation:

- Uncertainties considered during the TRM calculation are as follows
  - Unintended deviations of physical flows during operations due to physical functioning of load-frequency regulation.
  - Emergency exchanges between TSOs to cope with unexpected unbalanced situations in real time.
  - Inaccuracies, e.g., in data collection and measurements.

CBM Calculation:

- CBM is not considered by Nordic TSOs though it is explicitly used in North America. Therefore, it is always set to zero while calculating the NTC in Europe.

Nordic TSO: ATC

ATC calculation:

- Instead of ATC, in Nordic system it is termed as Net Transfer Capacity (NTC).
- It is defined as the maximum exchange program between two areas compatible with security standards applicable in both areas and taking into account the technical uncertainties on future network conditions.

$$NTC = TTC - TRM$$

TTC/ATC Calculation Methodology Comparison

Utility	Methodology	TRM	CBM
BC Hydro, Canada	Rated System Path	Yes	No
IESO, Canada	Rated System Path	Yes	No
CISO, USA	Rated System Path	Yes	No
PacifiCorp, USA	Rated System Path	Yes	No
BPA, USA	Rated System Path	Yes	No
PJM, USA	Flowgate	Yes	Yes
SPP, USA	Flowgate	Yes	No
TVA, USA	Flowgate	Yes	Yes
FPL, USA	Area Interchange	Yes	No
Nordic TSO, Europe	Own Procedure	Yes	No
Tennet TSO GmbH, Europe	Own Procedure	Yes	No
CTU/POSOCO	RSP + Area Interchange	Yes	No

Recommendations

Recommendations: Methodology

- Review of SOL and TTC calculation practices in North America and Europe and comparing their power system characteristics to that of India, it is recommended that the combination of Rated System Path methodology and Area Interchange methodology which is being used currently appears to be the most suitable method to be used for transfer capability calculations.
- It is highly recommended that :
  - CTU as a transmission planner may calculate the SOL in the planning horizon.
  - POSOCO (NLDC along with RLDCs) should continue calculating the TTC in the operation horizon.

Recommendations: Methodology

- SOL is a reliability based calculation and widely used by many BAs in North America. Although TTC is a commercial term in North America, it is a reliability based calculation in India. SOL should be calculated firmly based on the facility rating, voltage limit, voltage and transient stability limits. TTC, however, respects the SOL in all horizons. In addition, TTC also respects various commercial issues, contracts, and allocations.
- Depending on the system topology, TTC and SOL can be set to be the same in the operation horizon as it is in the case of Indian power system where no contract transmission capacity is considered during the development of a base case.

Recommendations: Methodology

- As per Indian Electricity Act 2003, CTU, NLDC and RLDCs shall not engage in the business of trading in electricity.
- Therefore, they should only discharge their duties relating to calculation of TTC/ATC in operation horizon and no private entity/stakeholder should be allowed to participate in that calculation process.
- Similarly, as a system planner and open access provider CTU should only calculate the SOL and no private entity/stakeholder should be allowed to participate in SOL calculation process.
- However, POSOCO and CTU both entities may share the supporting documents showing all the assumptions and consideration used in their SOL and TTC/ATC calculations.

Guidelines: SOL Calculation

Observations:

- Planning horizon usually consists of two types: near-term planning (1-5 years) and long-term planning (1-10 years).
- The current TTC calculation is a reliability-based calculation, which does not include any commercial contracts.

Guidelines for SOL in Planning Horizon:

- The SOL could be, among other things, a limit of power flowing on a line or path, a total generation limit in an area, or a limit on the total export of power from or to an area.

Guidelines for SOL in Operation Horizon:

- TTC derived by POSOCO is same as SOL in operation horizon in the context of Indian power system. Therefore, there is no need of SOL calculation in operation horizon.

Guidelines: SOL Calculation

Study Model and Assumptions:

- Study models used in the determination of SOLs by CTU should use the base cases developed by CTU which include the entire national, inter-state and regional transmission system.
- Study models must reflect the most accurate representation of transmission system configuration and ratings, generation and load in the study area for the time period of the study.
- Study assumptions including load levels, generation dispatch, and transfer flows should reflect expected system operating conditions and should be appropriate for the study.
- All relevant facilities should be within their normal thermal ratings and voltage limits.

Guidelines: SOL Calculation

Power Flow Analysis:

- Power flow analysis is used to evaluate system performance under normal and applicable single and multiple contingency conditions to identify facilities whose thermal or voltage (including voltage stability) limits may be violated.
- Power flow analysis can also be used to further evaluate the risk and impact of cascading associated with excessive thermal overloading.
- It is understood that currently CTU mainly employ thermal overload criteria for the calculation of transfer capability.
- Gradually when model deficiencies are corrected, voltage collapse criteria should be adopted for the transfer capability calculations.

Guidelines: SOL Calculation

Selection of Applicable Credible Contingencies:

- All single and multiple contingencies associated with or that could limit the operation of the facility or facilities under study, including those outside the CEA planning criteria, should be studied.
- Applicable contingencies may be selected based on previous studies, established knowledge of the system in the study area and contingency screening studies.
- A description of the contingencies studied along with the rationale for selecting the contingencies should be documented that would be useful for future studies.

Powertech

Guidelines: SOL Calculation

Selection of Applicable Monitored Facilities:

- All facilities in the study area that could be impacted by the SOL of the facility or facilities under study, including those that are outside the CEA planning criteria, should be monitored.
- These remedial measures may include generation and load dropping and automatic series and shunt capacitor switching.

Powertech

Guidelines: SOL Calculation

Post-transient Analysis (Transfer Studies):

- The post-transient analysis is employed to further evaluate a limited number of critical contingencies where the results may represent a more accurate system response.
- For contingencies that cause simulations to diverge - which signals voltage instability post-transient voltage stability analysis may be performed using the PV method to determine the SOL.
- Although CTU currently does not employ voltage stability based transfer capability calculation it may consider this in future to align with international practices.

Guidelines: SOL Calculation

Transient Stability Analysis:

- All credible single and multiple contingencies must be run.
- Simulation should run at least for 10 s to capture the post-contingency performance of the system.
- Post-contingency system damping should be within 5% for a stable system.
- Transient voltage should recover to an acceptable level with specified time interval after the fault is cleared.

Guidelines: TTC Calculation

- POSOCO shall follow the similar guidelines as made for SOL calculation.
- The power flow cases should be periodically checked and compared against the measured quantities and actual responses of the power system whenever possible.
- Transmission system, generators and loads must be modeled appropriately as recommended. Once the base case is developed the following should be checked:
  - Accurate system topology.
  - Reasonable load and generation levels for the time period of the study.
  - Acceptable voltage profiles across the system.
  - Correct facility ratings for the study case.

Guidelines: TTC Calculation

- The transmission facility outage is one of the most important but being limited to a few days per year.
- POSOCO may consider an annual outage plan approved by RPCs, which will provide sufficient information about the planned transmission outages in the TTC/ATC calculation horizon.
- A concrete outage management and coordination policy regulatory framework should be in place to provide adequate technical requirements and criteria for transmission operations, maintenance, and construction staffs.
- POSOCO needs to define urgent, emergency and planned outages for all transmission elements for the calculation of TTC which can impact the system and/or reduce system capacity for paths, in order to meet reliability and safety standards, compliance requirements and availability requirements.

Guidelines: TRM Calculation

- Currently CTU and POSOCO mainly apply thermal limit for TTC calculation.
- It is recommended that until voltage stability criteria are adopted for the SOL and TTC calculation, facility rating reduction methods may be adopted for the establishment of TRM.
- In order to avoid an overly conservative TRM value, sensitivity study is recommended.
- Various components of uncertainties must be considered and documented for future reference.
- Uncertainties such as allowances for simultaneous path interactions, short-term system operator response, reserve sharing requirements, inertia response and frequency bias in AGC may be considered in future.

Guidelines: CBM Calculation

- Currently POSOCO does not allocate any CBM.
- Based on the extensive investigation, it is not recommended to use CBM in the calculation of ATC.
- POSOCO may set CBM to zero when calculating ATC for each of its ATC paths.

Guidelines: ATC Calculation Frequency

- POSOCO currently calculates monthly ATC for next three months; it is highly recommended to continue calculating the monthly values for at least next 12 months. This will substantially reduce the existing modeling differences between CTU and POSOCO base case models.
- In future, POSOCO may consider calculating ATC daily for at least next 31 days. This, however, largely depends on the future commercial activities and related regulations, as well as availability of resources.
- All five regions (RLDCs) under NLDC should follow similar ATC calculation periods and calculate their ATC for each of their ATC paths.

Guidelines: ATC Documentation/Publication

- POSOCO shall prepare a document describing how the methodology has been implemented, in such detail that results of ATC calculation can be validated.
- When calculating the ATC, NLDC and RLDCs shall use assumptions no more than those used in the planning of operations for the corresponding time period studied, providing such planning of operation has been performed for that time period. These study assumptions should be shared among all stakeholders and made public.
- NLDC and RLDCs should recalculate the ATC only if at least one of the calculated values identified in the ATC equation has been changed.

Recommendations: Data Requirements

- Power flow and stability studies requires most accurate computer models of the power system.
- The accuracy of these models is a key factor in preserving system reliability and it also affects significant economic decisions regarding system expansion and operation.
- System representation should be sufficiently accurate to ensure that system parameters measured in simulating a disturbance are close to those that would be measured on the actual power system under the same conditions.

Recommendations: Data Requirements

- Study results either overly optimistic or too pessimistic could lead to uninformed decisions regarding the design or operation of the power system and potentially negatively affect reliable operation.
- Dynamic data resulting from equipment testing should be provided if it is available. If test data is not available then design data should be provided. If design data is not available then generic dynamic data should be provided.
- As a common practice in North America, in-service equipment are supported by test data while long-term planned equipment only have generic dynamic data available.
- A similar approach should adopted by Indian Power System planners and operators.

Recommendations: Data Requirements

What kind of data?

Data format and content requirements required for the development of base cases for all types of studies is broken into three data types:

- **Steady state data:** used for power flow and transfer analysis.
- **Dynamics data:** used for transient studies and small-signal studies.
- **Short circuit data:** used to evaluate the adequacy of circuit breakers and other protective devices in the system.

Recommendations: Steady-State Data – Buses

Buses:

- Buses usually represent all of the equipment in a substation that is at the same voltage level and is connected together. If desired, multiple bus sections can be represented by separate buses connected by AC transmission line models that can be opened or closed as needed.
- Location of the bus will be identified by the combination of Area, Zone, and/or Owner fields.

The current method of bus numbering adopted by CTU and POSOCO is sufficient. However, both use different number for same node. It is preferable that both have identical area codes, zones, bus numbers, etc., to facilitate easy data exchange.

Recommendations: Steady-State Data – Generators

Generators:

- Although all generators above 50MVA are modeled, it is desired to model all generators/plants including IPPs above 20 MVA.
- Synchronous condensers shall be modeled individually using a generator model.
- Generator step-up transformers shall be modeled explicitly and they shall not be embedded in generator models so that unit actual P and Q limits (directly based on unit capability curves) can be accurately observed particularly for voltage stability constrained transfer analysis.
- Generator maximum real power PMAX in power flow must be consistent with the turbine capabilities provided in the dynamic data.

Recommendations: Steady-State Data – Renewables

Renewable Sources:

- Wind and photovoltaic plants shall be represented through an equivalent generator(s), equivalent low-voltage to intermediate-voltage transformer, equivalent collector system, and substation transformer between the collector system and the transmission bus.

Recommendations: Steady-State Data – Loads

Loads:

- Real and reactive power for each load should be provided as well as load characteristic if available (preferably represented at delivery points rather than lumped on EHV buses).
- Induction motors should be modeled as a load with the intent of using an induction motor model. Currently CEA criteria manual does not have any provision on how to model induction motor loads except motor loads of pumped storage plants.
- Station service load (auxiliary load) shall be modeled explicitly.
- Industrial loads and embedded generation shall be modeled on the low side of the transformer.

Recommendations: Steady-State Data – Transmission Lines

AC Transmission Lines:

- Each transmission owner should provide accurate nominal voltage, impedance, line charging, normal and emergency rating of all the AC transmission lines it owns. The existing CEA manual suggests an emergency thermal limit be 110% of the normal thermal limit in planning studies.
- Series connected reactive devices modeled in AC transmission lines shall be explicitly modeled.

HVDC Links:

- DC Transmission facility owner should supply the line parameters, normal and emergency ratings, control parameters, rectifier data, and inverter data.
- MW set-point of converter data shall be equal to or less than the DC transmission line rating

Recommendations: Steady-State Data – Shunts

Fixed Shunt Reactive Elements:

- Fixed shunt elements that are directly connected to a bus should be modeled explicitly.
- Fixed shunt elements that directly connect to a transmission line should be represented as line shunts so that they can be switched in and out with the transmission line.
- Fixed shunt reactive devices inside wind and solar power plants should be modeled explicitly in power flow model as well.

Recommendations: Steady-State Data – Shunts

Controlled Shunt Reactive Devices:

- Controlled shunt reactive device models should be used to represent the following devices explicitly in power flow model:
  - Mechanically switched shunt capacitors and reactors.
  - Static VAr Compensators (SVCs) including thyristor switched shunt capacitors and reactors.
  - Static Synchronous Compensators (STATCOMs).
- SVCs/STATCOMs inside wind and solar power plants should be modeled explicitly in power flow model, if feasible.
- A number of fixed shunts and SVCs/STATCOMs are modeled in the CTU and POSOCO base cases; however, there are no switchable shunts modeled explicitly in the base cases.

Recommendations: Dynamic Data

- Dynamic simulations are typically performed only for selected credible contingencies to assess any potential constraints due to transient stability. Dynamic data is therefore required to carry out the transient stability studies.
- Currently, there is no consistent data format or collection mechanism practiced in India. Therefore, it is highly recommended that CEA, CTU, POSOCO, and all STUs should make necessary arrangements to address this issue.
- It is suggested that some institutional arrangement may be established for existing and planned power system data collection and validation. There should be common data base which could be utilized by CEA, CTU, POSOCO, and all STUs.

Recommendations: Dynamic Data

The dynamic data requirements may include the following:

- Dynamic data for generators, synchronous condensers, excitation systems, voltage regulators, turbine governor systems, power system stabilizers, and other associated generation equipment shall be submitted by the facility owners.
- Power System Stabilizer (PSS) dynamic data shall be submitted for all generators that have active PSS.
- Whenever possible voltage and frequency characteristics of each individual load should be modeled.
- All HVDC controls, HVDC lines, STATCOM and SVC systems should be modeled to the maximum extent possible in order to accurately reflect actual system performance.

Recommendations: Training and Development

- To calculate SOL and TTC/ATC for the entire country suitable software and staff with deep subject knowledge are required.
- To improve the expertise of engineers and choose correct tools, Government of India needs to arrange training and workshops for planning and operation engineers in regular intervals.
- Several technical committees and working groups may be setup by Government of India to look after various technical challenges involved in SOL and TTC/ATC calculations.
- Verify existing criteria/procedures/standards periodically.
- The new standard may be created by introducing guidelines for developing base cases/preparing list of credible contingencies and updating the list periodically/developing scheduled outage documents.

Recommendations: Training and Development

- Planning and operation engineers should be aware of ratings and limitations of all those elements that may affect the path operating limit and/or transfer capability.
- It is the responsibility of the facility owner to specify their equipment operational limits and report any change in ratings or status to the transmission operator.
- Transmission operator then needs to provide this information to planner if the change in rating/status is permanent or may affect long-term planning process.
- A document/database may be created to list those critical elements, their settings, and operating guidelines, which should be accessible to study engineers to ensure that these elements are properly modeled in the planning and operation cases.

Recommendations: Trainings for Engineers

- SOL and TTC/ATC calculations involve the use of sophisticated software, proper training would be essential for engineers to learn and use those tools.
- Training courses on voltage stability, power system control and operation, and real-time power system stability analysis should be arranged to enhance the subject knowledge of engineers.
- These training sessions may be arranged periodically on an "as needed" basis.
- Develop a process to determine specific training needs for the engineers.
- Clarify the goals of each training session.

Recommendations: Workshop for Engineers

- Government of India (Ministry of Power) may conduct workshops at the national level and/or regional levels to train the engineers. Key features of these workshops are as follows:
  - Should be small, usually from 5 to 15 participants, allowing everyone some personal attention and the chance to be heard.
  - Should be designed for people who are working together, or working in the same field.
  - Should be conducted by people who have experience in the subject under discussion.
- Use of new software and simulation techniques using practical cases must be included in these workshops.
- Active collaboration with educational institutes and power system analysis software developer may help in arranging these workshops.

Recommendations: Conferences

- Conferences always provide an excellent platform for academician and industry people to exchange their ideas.
- Govt. of India may consider arranging conferences on power system security and reliability which will provide an opportunity to invite internationally renowned professors and subject experts from different states/countries.
- Engineers should also be encouraged to carry out research work, attend various conferences and present their works.

Recommendations: Committees

- There is a need to develop standards for reliability criteria for power system planning and operation.
- CEA may setup mechanism to develop these standards for reliability criteria.
- Existing security criteria should be reviewed and modified periodically.
- Further, a mechanism for enforcing and compliance of the same should also be established within the legal framework.
- It is suggested that some institutional arrangement may be established for existing and planned power system data collection and validation.
- It is strongly recommended that no committee member should have any controlling interest in any market player.

Thank You

The Power of Trust. **The Future of Energy.**

Consultancy Contract to Review Transmission System Transfer Capability and Review of Operational and Long Term Planning (Pkg B)

Saeed Arabi and Zhihong Feng

February 15, 2018

Project Tasks

- Task I: Examination and recommendation of methodology for optimum calculation of transfer capability in the planning and the operational horizons
- **Task II: Calculation of transfer capability for the entire country**
- Task III: Guidelines for developing and implementing system protection schemes and islanding schemes, and review of existing schemes
- Task IV: Operational planning and long term planning for secure and efficient operation of the grid
- Task V: Suitable suggestions in the Regulatory framework to ensure secure and efficient grid operation
- Task VI: Review of the tuning of all power electronic devices and suggesting retuning of setting of these devices, as per "Taskforce Report on Power System Analysis"

Task II Specifics

- **Calculate transfer capabilities** at State level, regional level, and national level for existing system and up to 2016-17 time frame as per planned/under implementation transmission system, including optimization of set points of various HVDC stations
- **Estimate required transfer capabilities** at State level, regional level and national level for existing system and up to 2016-17 time frame as per planned/under implementation transmission system
- **Provide suggestions for addressing the gap** between required transfer capabilities and calculated transfer capabilities for existing system and up to 2016-17 time frame as per planned/under implementation transmission system

Methodology: Terminologies

- **Rated System Path (RSP):** used widely for well-defined paths
- **Area Interchange (AI):** used for contract paths
- **Flowgate:** used for constraints on subsets of transmission paths
- POSOCO and CTU presently use a combination of RSP and AI
- Main differences among the three methodologies:
  - The way network topologies are interpreted
  - The way models are prepared
  - The way transfer (stressing) patterns are defined
- From computational point of view to predict system response, all three methods are essentially the same
- Computations oriented toward System Operating Limit (SOL) determination – a reliability-based terminology
- Commercial terminologies: TTC (essentially SOL for single contingency), TRM, and ATC

Methodology: Computations

- **Stressing the system** with transfers (i.e., source-sink pairs) under credible contingencies, while appropriate criteria are applied
- TTC terminology is used even if it is SOL – TRM/ATC for operation
- Feb16 peak and off-peak cases (POSOCO)
  - Data issues led to **Feb16 peak+**
- Mar17 peak and off-peak cases (CTU)
  - Data issues led to **Mar17 peak+**
- Voltage stability margin is applied through **PV** (voltage versus active power) analysis using VSAT
  - PV is not bus dependent – unlike QV method which is bus dependent
  - PV is oriented toward realistic way of stressing the system – unlike fictitious way in QV
  - PV also provides for finding thermal limits along the way

Methodology: Major PV Analysis Users

- BC Hydro
- Alberta Electric System Operator (AESO)
- Manitoba Hydro
- Independent Electricity System Operator (IESO)
- San Diego Gas & Electric (SDG&E)
- Electric Reliability Council Of Texas (ERCOT)
- Midcontinent Independent System Operator (MISO)
- ISO New England (ISO-NE)
- International Transmission Company (ITC)
- American Transmission Company (ATC)
- FirstEnergy Corporation
- Electric Power Transmission Operator in Ireland (EirGrid)
- Australia Energy Market Operator (AEMO)
- Transpower New Zealand Limited (TPNZ)
- Korea Power Exchange (KPX)

Methodology: Simulation Tools

- PLI's DSA*Tools*™ software:
  - Power-flow and Short-circuit Analysis Tool (PSAT)
  - Voltage Security Assessment Tool (VSAT)
  - Small-signal Stability Analysis Tool (SSAT)
  - Transient Security Assessment Tool (TSAT)
- Convert power flow and dynamic data from PSS/E format
- Special models may be set up as User-Defined Models (UDMs)
- Sanity checking of data:
  - Power flow data checking by PSAT and VSAT
  - SMIB scan of every generator/controls by SSAT
  - Dynamic data checking by TSAT
  - Various data tabulations of all programs for visual checks and inventories

Methodology: Generator & Load Models Constraints

- Generating units are modelled at the HT side, mostly with implicit step-up transformers (GSU), generally using typical parameters
  - Q_{MAX}/Q_{MIN} and P_{MAX}/P_{MIN} need to be corrected for transformer MVAr/MW losses (which change with loading) and station loads
  - In North America the tendency is toward explicit modelling, which gives more flexibility and less possibility for oversight and approximation
- Loads are lumped at HT (not delivery) buses, implicitly containing their power factor correction capacitors, and without explicitly representing their Under-Load Tap Changing (ULTC) transformers
  - Include the effect of transmission lines and transformers of the path
    - Constant power representation is wrong for these contributions
    - Scaling the load would also result in (wrongly) scaling these contributions
  - Shunt capacitor characteristic is different (constant impedance)
  - ULTCs are needed for proper adjustments after each outage (locking them for contingency solution can be done through simulation setups)

Methodology: Other Model Constraints

- Shunt reactors/capacitors are modelled as fixed shunts, which do not provide the flexibility for automatic adjustments
  - Switched shunts may be locked for contingency solution if their actual switching is manual
  - Fixed line-end reactors to be modelled as part of the line shunt admittance
- The model inflexibilities prevent automatic adjustments in preparation for contingencies, e.g., N-1-1, etc.
- A number of bus voltage and branch loading violations at voltage levels below 400 kV (STU)
  - Loads of up to 60 buses were softened by changing their representation from constant power to constant impedance to avoid numerical problems
- Some of the deficiencies were rectified in the peak+ cases, but inflexibilities remained

Methodology: Power Flow Inventories – Peak+ Cases

- Inconsistencies between POSOCO and CTU cases should be avoided as much as possible

In-service Elements	Feb16 Peak+	Mar17 Peak+
AC Buses	7162	5466
Generators	1282	1375
Loads	4183	3164
Fixed Shunts	1006	767
Continuous Switched Shunt (SVC)	1	4
Zero-impedance Lines ($Z \leq 0.0001$)	112	196
Non-zero-impedance AC Lines	10300	8567
Series Compensation Circuits	36	39
Two-winding Transformers	2977	2329
Two-terminal HVDC Systems	10	10

Methodology: Power Flows – Earlier Cases

- Inconsistencies between POSOCO and CTU cases should be avoided as much as possible

In-service Elements	Feb16 Peak	Feb16 Off-Peak	Mar17 Peak	Mar17 Off-Peak
AC Buses	6497	6496	5459	5453
Generators	1093	936	1372	1022
Loads	3761	3765	3162	3162
Fixed Shunts	844	918	767	931
Continuous Switched Shunt (SVC)	1	1	1	1
Zero-impedance Lines ($Z \leq 0.0001$)	105	105	196	194
Non-zero-impedance AC Lines	9224	9217	8559	8548
Series Compensation Circuits	29	27	39	37
Two-winding Transformers	2795	2797	2324	2322
Two-terminal HVDC Systems	10	10	10	10

Methodology: Dynamic Data – Earlier Cases

- Almost all data is typical (and at times wrong typical values)
  - Try to avoid GENCLS – we added self damping to avoid oscillations
- POSOCO and CTU models/data are not consistent?

Device	Model	Feb16 Peak	Feb16 Off-Peak	Mar17 Peak	Mar17 Off-Peak
Generator	GENROU	691	608	777	599
	GENSAL	389	317	467	327
	GENCLS	7	5	128	96
Exciter	ESST1A	18	18	-	-
	EXAC1	-	-	60	49
	EXAC2	7	6	-	-
	EXPIC1	-	-	84	77
	EXST1	-	-	26	15
	EXST2	-	-	7	7
	IEEET1	882	752	359	307
	IEEET2	4	4	123	89
	IEEEX1	4	3	116	46
	SCRS	2	2	270	185
	SEXS	-	-	183	138
Governor	GAST	-	-	2	-
	HYGOV	235	205	144	110
	IEEEG1	1	1	218	166
	TGOV1	354	313	99	87
Power System Stabilizer (PSS)	IEEEST	-	-	319	248
	PSS2A	34	32	-	-
	PSS2B	3	7	-	-
SVC	CHSVCT	1	1	1	1
HVDC Pole	CMDWAST	18	18	-	-
	CDC4T	-	-	19	19

Powertech

Methodology: Voltage Security Criteria – Peak+ Cases

- **Branch Overload:** For both pre- and post-contingency situations 100% of rating of lines (Rate B) and transformers (Rate A), applied to branches connected to ≥ 400 kV Inter-State Transmission System (ISTS) buses, including 400/220 ICTs
  - **Hard limits:** If they are part of the interfaces along the analyzed transfers
  - **Soft limits:** Otherwise (registered but not included in TTC)
  - POSOCO and CTU asked for changing certain ratings in base power flows:
    - Each Agra-Gwalior 765 kV circuit: 2750 MVA in Feb16
    - Each Sholapur-Raichur 756 kV circuit: 2500 MVA in Feb16
    - Each Gwalior-Bina 765 kV circuit: 3000 MVA in Mar17
    - Each Sholapur-Parli 400 kV circuit: 1100 MVA in Mar17
- **Voltage Stability Margin:** 5% for single contingencies (common everywhere), i.e., MW value at the first encountered voltage collapse point is divided by 1.05 to arrive at TTC
  - For double/multiple contingencies the suggested margin is 2.5%

Methodology: Additional Criteria for Earlier Cases

- **Voltage Magnitude Min/Max:** 0.94/1.06 pu at 765 kV buses and 0.92/1.08 pu at 400 kV after single contingencies (soft limits)
  - Chosen to avoid observing pre-contingency violations in base cases
  - They are somewhat wider than CEA criteria (i.e., 728/800 at 765 kV buses and 380/420 at 400 kV buses)
  - In North America post-contingency voltage criteria are typically 0.9-1.1 pu: Much wider than those of CEA
    - 0.95-1.05 pu typical for pre-contingency (same as CEA)
- **Line Maximum Angle Difference:** Not to exceed 30 degrees, applied to lines of ≥ 400 kV level, just as a screening measure and not a limiting criterion (a rule of thumb – soft limit)
- **Transient Stability:** Synchronism for single contingencies
- **Small-Signal Stability:** Suggest minimum damping ratio of 3%

Methodology: Applied Contingencies

- Scanned for single contingencies of ISTS using VSAT:
  - All ac lines and transformers connected to $\geq$ 400 kV ISTS buses
    - For earlier cases non-ISTS buses were also included (~ twice branch contingencies)
  - Largest generating unit of each region
    - For earlier cases large generators of all regions (around 50 contingencies)
  - One pole of every HVDC link

Case	Single Branch 400 & 765 kV with Step-down Transformers	Single Generator Largest Unit of Each Region	Single Pole All HVDC Links
Feb16 Peak+	1009	5	10
Mar17 Peak+	1283	5	10

Methodology: Inter-Regional Transfers – Peak+ Cases

- Generation increase is implemented by scaling up the output of every in-service unit of the corresponding regions in proportion of its MW reserve
- For generation decrease:
  - Available **merit order** of the Inter-State Generation Stations (ISGS) is applied first
    - Minimum limit of the units is not respected to avoid a large step change (common practice)
  - Once merit order is exhausted, the in-service units of certain States are scaled down in proportion of the current output of each unit

Transfer ID	Transfer Type (Source-Sink)	Simultaneous Source Regions	Sink Region
NR-Import	Generation Increase-Generation Decrease	WR & ER (70% & 30%, to be in line with the natural flow capabilities of the two parallel paths)	NR
SR-Import	Generation Increase-Generation Decrease	WR & ER (80% & 20%)	SR

Methodology: NR-Import Transfer – Peak+ Cases

- Transfer steps of 50 MW are used, while at each step all single contingencies are applied using nonlinear power flow solutions

Feb16 Peak+ Generation Decrease			Mar17 Peak+ Generation Decrease		
Bus #	**Bus Name**	**Unit ID**	**Bus #**	**Bus Name**	**Unit ID**
154056	SINGRL4 400.	1			
154056	SINGRL4 400.	2			
154056	SINGRL4 400.	3			
154057	RIHAND-G 400.	4			
154057	RIHAND-G 400.	5			
154057	RIHAND-G 400.	6	182236	ANTA-GPS 220.	G3
134029	ANTA2 220.	G1	182236	ANTA-GPS 220.	S1
134029	ANTA2 220.	S1	182238	DADRI-GPS 220.	G3
152103	DADRI_G2 220.	G1	182238	DADRI-GPS 220.	G4
152103	DADRI_G2 220.	S1	182238	DADRI-GPS 220.	S1
152103	DADRI_G2 220.	G2	182238	DADRI-GPS 220.	S2
152103	DADRI_G2 220.	S2	182267	UNCHAHAR 220.	4
154058	UNCHAHR2 220.	4	182267	UNCHAHAR 220.	5
154058	UNCHAHR2 220.	5	184424	DADR-II-STPS400.	6
154061	DADR-NCR 400.	5	182907	DADRI-I-STPS220	3
152104	DADRI_TH 220.	3	182907	DADRI-I-STPS220	4
152104	DADRI_TH 220.	4	182907	DADRI-I-STPS220	SW
152104	DADRI_TH 220.	SW	184400	JHAJJHAR 400.	2
124023	JHAJJAR4 400.	2	184400	JHAJJHAR 400.	3
124023	JHAJJAR4 400.	3	182234	AURAIYA-GPS 220.	G2
154060	AURYA2 220.	G2	182234	AURAIYA-GPS 220.	G3
154060	AURYA2 220.	G3	182234	AURAIYA-GPS 220.	G4
154060	AURYA2 220.	G4	182234	AURAIYA-GPS 220.	S1
154060	AURYA2 220.	S2	182234	AURAIYA-GPS 220.	S2
States			**States**		
Punjab, Haryana, Rajasthan, Delhi, Uttar Pradesh, Uttrakhand, Himachal Pradesh, J&K, Chandigarh			Haryana, Delhi, Rajasthan, Uttar Pradesh, Uttrakhand		

Methodology: SR-Import Transfer – Peak+ Cases

- Transfer steps of 50 MW are used, while at each step all single contingencies are applied using nonlinear power flow solutions

Feb16 Peak+ Generation Decrease			Mar17 Peak+ Generation Decrease		
Bus #	Bus Name	Unit ID	Bus #	Bus Name	Unit ID
			544088	VTPS 400.	2
444019	NTECL-VALLUR400.	2	544088	VTPS 400.	3
444019	NTECL-VALLUR400.	3	514001	RSTP 400.	2
424002	RSTPS NTPC 400.	1	514001	RSTP 400.	3
424002	RSTPS NTPC 400.	2	514001	RSTP 400.	6
424002	RSTPS NTPC 400.	3	514001	RSTP 400.	7
424002	RSTPS NTPC 400.	7	542071	TUTI TPS 230.	3
444021	TUTICORINJV 400.	2	542071	TUTI TPS 230.	4
414012	SIMHADRI-I 400.	2	542071	TUTI TPS 230.	5
441097	NLCTS11 110.	1	514015	SIMHD-II 400.	2
441097	NLCTS11 110.	2	544001	NYVL 400.	4
441097	NLCTS11 110.	3	542001	NEYVELTS2 230.	2
442053	NLC22 230.	3	542001	NEYVELTS2 230.	3
442052	NLCTS12 230.	9	542046	NEYVELITS12 230.	9
States			States		
Telangana, Andhra Pradesh, Karnataka, Tamil Nadu, Kerala, Puducherry			Andhra Pradesh, Telangana, Karnataka, Kerala, Tamil Nadu		

Methodology: Inter-Regional Transfers – Earlier Cases

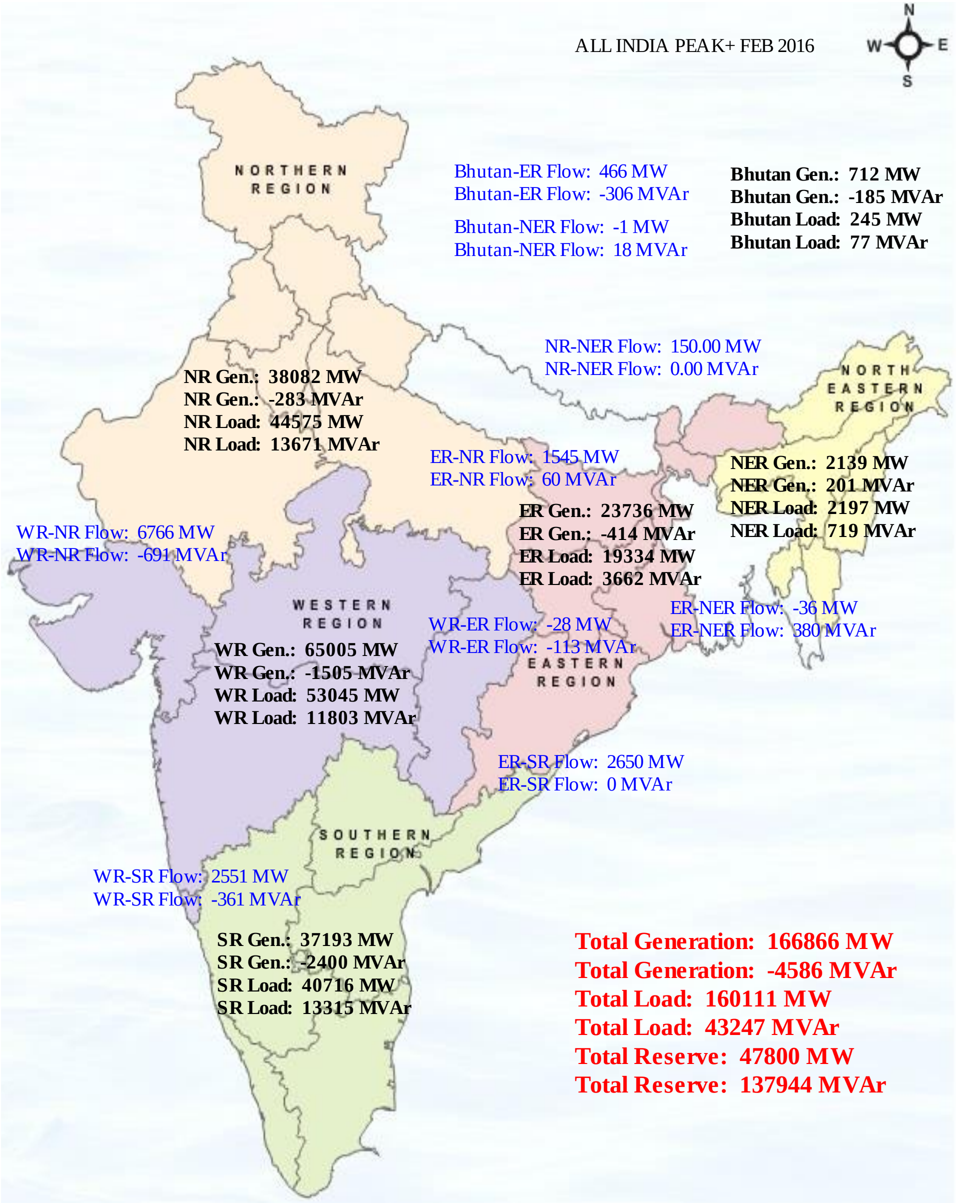
- No merit order was available at the time
- Load scale-up was used to avoid generation scale-down leaving units online similar to synchronous condensers (unrealistic)
- Load decrease-generation decrease philosophy was applied to establish some initial flow in the reverse direction (unreliable)

Transfer ID	Transfer Type (Source-Sink)	Source Regions	Sink Regions
NR-WR	Load Decrease-Generation Decrease Generation Increase-Load Increase	NR	WR
WR-NR	Generation Increase-Load Increase	WR	NR
NR-ER	Load Decrease-Generation Decrease Generation Increase-Load Increase	NR	ER
ER-NR	Generation Increase-Load Increase	ER	NR
WR-SR	Generation Increase-Load Increase	WR	SR
ER-SR	Generation Increase-Load Increase	ER	SR
ER-NER	Generation Increase-Load Increase	ER	NER
NER-ER	Load Decrease-Generation Decrease Generation Increase-Load Increase	NER	ER
NR-Import	Generation Increase-Load Increase	WR & ER (50% & 50%)	NR
SR-Import	Generation Increase-Load Increase	WR & ER (80% & 20%)	SR
NR-Export	Load Decrease-Generation Decrease Generation Increase-Load Increase	NR	WR & ER (50% & 50%)

Methodology: State-wise Transfers – Earlier Cases

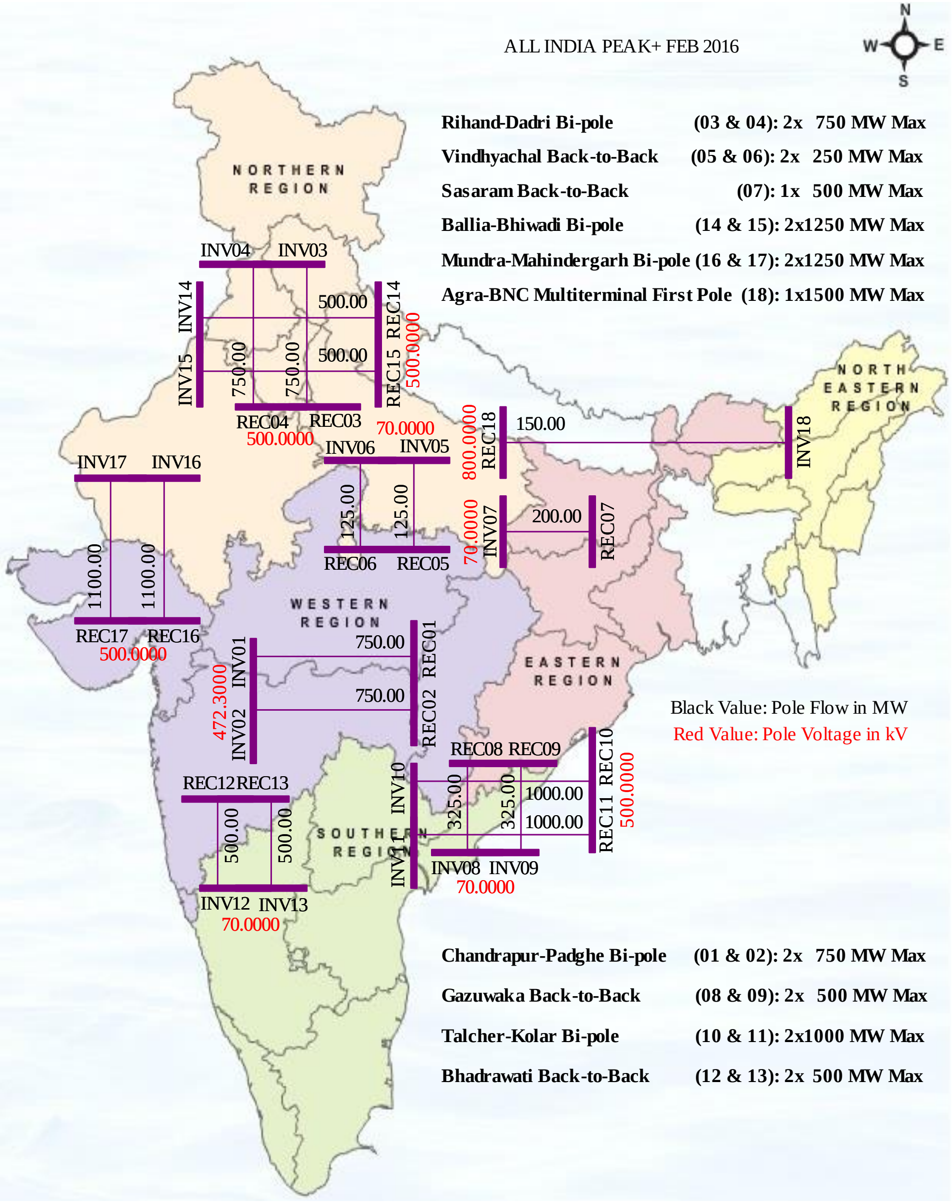
- Absorption by each State from the rest of the region
  - 9 NR States as sink
  - 7 WR States as sink
  - 6 ER States as sink
  - 5 SR States as sink
  - 7 NER States as sink
- Injection by each State to the rest of the region
  - 9 NR States as source
  - 7 WR States as source
  - 6 ER States as source
  - 5 SR States as source
  - 7 NER States as source
- Generation increase-load increase philosophy was used

Feb16 Peak+ TTCs: Initial Loadings & Flows



Powertech

Feb16 Peak+ TTCs: HVDC Schematics



Powertech

Feb16 Peak+ TTCs: HVDC Optimization

- Mundra-Mahindergarh bi-pole flow is maximized to 2x1250 MW along NR-Import transfer
- Vindhyachal back-to-back flow is maximized to 2x250 MW along NR-Import transfer
- Sasaram back-to-back flow is maximized to 1x500 MW along NR-Import transfer
- Gazuwaka back-to-back flow is kept at its initial value along SR-Import due to a potential voltage collapse at its rectifier side
- Talcher-Kolar bi-pole flow is already at 2x1000 MW maximum
- Bhadrawati back-to-back flow is already at 2x500 MW maximum
- Agra-BNC multi-terminal not fully commissioned for this case
- Other links are intra-regional and not directly affecting inter-regional TTCs

Feb16 Peak+ TTCs: Violations

- Each violation is registered at its first occurrence

NR-Import MW Limit	Cause	Worst Contingency	Worst Violated Branch/State
9646	O/L	157007 AGRA-PG 765. 154034 AGRA 400. 1/2	157007 AGRA-PG 765. 154034 AGRA 400. 2/1
9697	O/L	157007 AGRA-PG 765. 327003 GWALIOR 765. 1/2	157007 AGRA-PG 765. 327003 GWALIOR 765. 2/1
10600	O/L	264008 FARAKKA 400. 264010 MALDA 4 400. 1/2	264008 FARAKKA 400. 264010 MALDA 4 400. 2/1
14252	O/L	154000 AGRAUP4 400. 154034 AGRA 400. 1/2	154000 AGRAUP4 400. 154034 AGRA 400. 2/1
15690	O/L	157007 AGRA-PG 765. 327003 GWALIOR 765. 2,1	324007 GWALIOR 400. 322009 GWALIOR 220. 1,2,3
17775	V/C	157004 BALI7-PG 765. 217001 GAYA_765 765. Q1	Bihar (ER)

SR-Import MW Limit	Cause	Worst Contingency	Worst Violated Branch/State
6409	O/L	337004 SHOLAPUR 765. 437001 RAICHUR-PG 765. 1/2	337004 SHOLAPUR 765. 437001 RAICHUR-PG 765. 2/1
7128	O/L	414003 NELLORE-PG 400. 414023 NELLORE-PS 400. 1/2	414003 NELLORE-PG 400. 414023 NELLORE-PS 400. 2/1
7804	O/L	314005 UKAI 400. 314020 NAVSARI 400. 1	314008 VAPI 400. 314010 SUGEN 400. 1
9238	O/L	337004 SHOLAPUR 765. 337005 AURANGABD-PG765. 1/2	337004 SHOLAPUR 765. 337005 AURANGABD-PG765. 2/1
9292	V/C	1 Pole Talcher-Kolar HVDC	Maharashtra (WR)

Feb16 Peak+ TTCs: Voltage Stability Limits

- Voltage stability limits with 5% margin from collapse points
- Worst contingency and State
- TTCs calculated by NLDC are dominated by overloads
  - At first, they are based on dc power flow solutions and linear extrapolation of their corresponding distribution factors in the network (approximation)
  - Then, verified using repeated power flows with full ac solutions for the known worst contingencies

Path	Feb16 Peak+ Initial Transfer (MW)			Feb16 Peak+ VS Limit (MW)			NLDC TTC (MW)
	From WR	From ER	Total	From WR	From ER	Total	Total
NR-Import	6766	1545	8311	12403	4526	16929	9950
SR-Import	2551	2650	5201	6200	2650	8850	6650

Path	Diverged Contingency in Feb16 Peak+	Worst State
NR-Import	157004 BALI7-PG 765. 217001 GAYA_765 765. Q1	Bihar (ER)
SR-Import	1 Pole Talcher-Kolar HVDC	Maharashtra (WR)

Feb16 Peak+ TTCs: Thermal Limits

- Overloads of the ac circuits of inter-regional interfaces
  - Occur when one circuit of the indicated Double-Circuit (D/C) line is disconnected causing overloading of the remaining circuit
- TTCs need to be reduced to these values if the corresponding Rate B values are actually the short-term (not continuous) ratings
  - No danger of voltage collapse
  - Intra-regional overloads are to be handled by operators (hence soft limits):
    - Re-connecting relevant out-of-service branches
    - Disconnecting the overloaded branches
    - Re-scheduling HVDC links
    - Re-scheduling generator outputs, etc.

Path	Contingency/Overloaded Interface Circuit	Feb16 Peak+ O/L Limit (MW)		
		From WR	From ER	Total
NR-Import	157007 AGRA-PG 765. 327003 GWALIOR 765. 1/2	7834	1863	9697
SR-Import	337004 SHOLAPUR 765. 437001 RAICHUR-PG 765. 1/2	3759	2650	6409

Feb16 Peak+ TTCs: NR Required Vs. Calculated

- Initial transfers are snapshots of the required inter-regional capabilities of the existing system
  - TTCs imply meeting these requirements with large margins
- Capabilities may reduce depending on:
  - Long Term Access (LTA)
  - Medium Term Open Access (MTOA)
  - Margin available for Short Term Open Access (STOA)

NR Generation Capacity Status	NR Generation Capacity (MW)	NR Peak Load (MW)	NR-Import Limit (MW)	Margin (MW)	Improvement Required
Initial	46505	44575	9697	11627	No
5% Reduction	44180	44575	9697	9302	No
10% Reduction	41855	44575	9697	6977	No
15% Reduction	39529	44575	9697	4651	No
20% Reduction	37204	44575	9697	2326	No
25% Reduction	34878	44575	9697	0	Yes

Feb16 Peak+ TTCs: SR Required Vs. Calculated

SR Generation Capacity Status	SR Generation Capacity (MW)	SR Peak Load (MW)	SR-Import Limit (MW)	Margin (MW)	Improvement Required
Initial	51561	40716	6409	17254	No
5% Reduction	48983	40716	6409	14676	No
10% Reduction	46405	40716	6409	12098	No
15% Reduction	43827	40716	6409	9520	No
20% Reduction	41249	40716	6409	6942	No
25% Reduction	38671	40716	6409	4364	No
30% Reduction	36093	40716	6409	1786	No
33.5% Reduction	34307	40716	6409	0	Yes

- After respectively 25% & 33.5% of base case generation dispatch reductions in NR and SR, system improvements are needed
- Since the limits are due to line overloads, increasing the thermal capacity of the involved circuits may be considered through increasing their clearances to the ground or re-conductoring
- Ultimate solution is addition of new transmission lines
  - Also effective for increasing voltage stability limits (& reactive resources)

Feb16 Peak+ TTCs: D/C Contingency Sensitivities

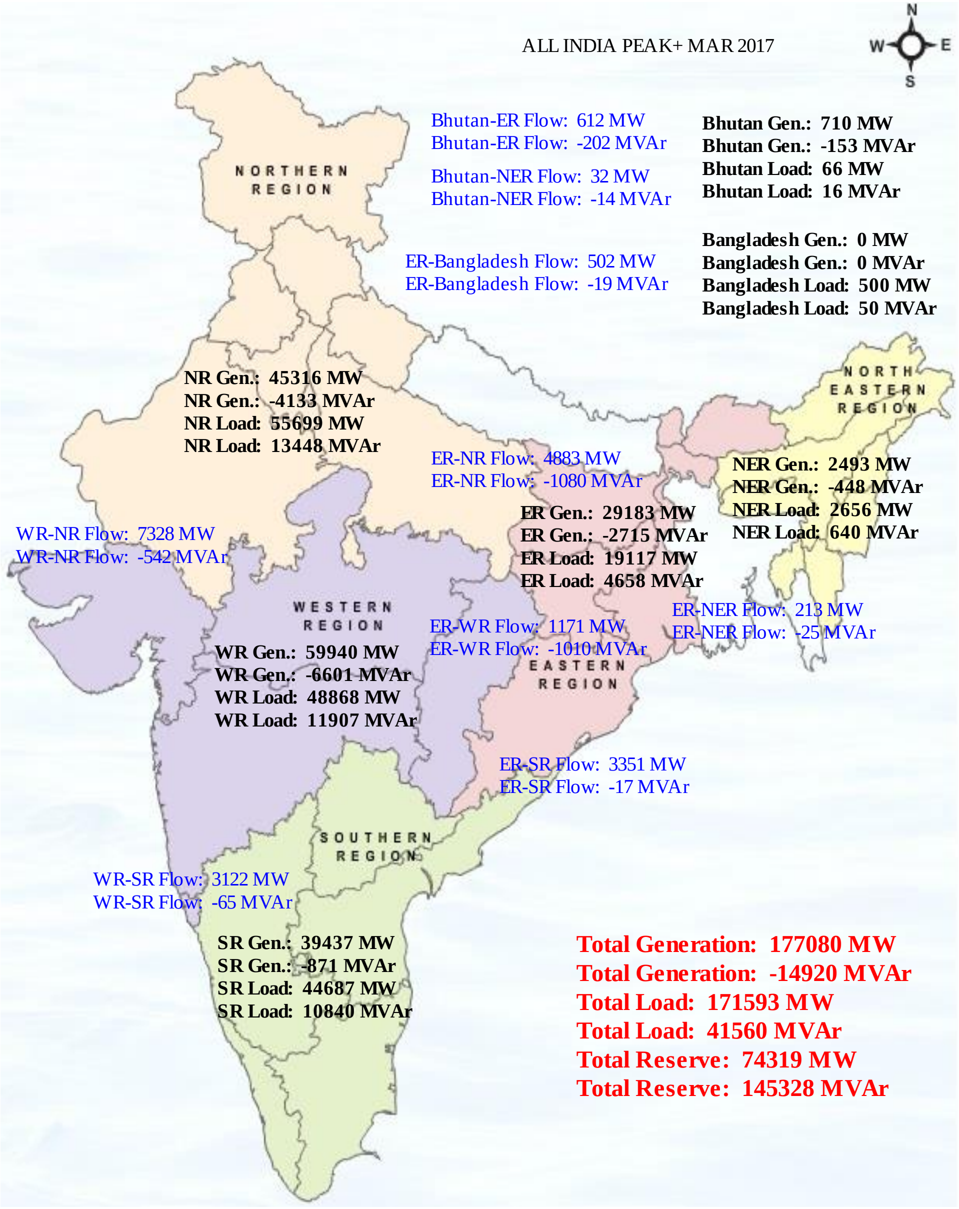
- Pre-outage of one circuit of 765 kV D/Cs for which the outage of one circuit causes overloading of the other circuit in SR-Import

SR-Import MW Limit	Cause	D/C Contingency	Violated Branch/State
5706	O/L	337004 SHOLAPUR 765. 337005 AURANGABD-PG765. 1&2	314008 VAPI 400. 314010 SUGEN 400. 1
6153	O/L	337004 SHOLAPUR 765. 337005 AURANGABD-PG765. 1&2	334015 AURANGABAD 400. 334055 PUNE_GIS 400. 1,2
6255	O/L	337004 SHOLAPUR 765. 337005 AURANGABD-PG765. 1&2	334040 SHOLAPUR-PG 400. 334041 PARLI-PG 400. 1,2
6921	V/C	337004 SHOLAPUR 765. 337005 AURANGABD-PG765. 1&2	Maharashtra (WR)

SR-Import MW Limit	Cause	D/C Contingency	Violated Branch/State
5051	O/L	337004 SHOLAPUR 765. 437001 RAICHUR-PG 765. 1&2	432119 NARENDRA-PG 220. 434017 NARENDRA 400. 1,2
5355	V/C	337004 SHOLAPUR 765. 437001 RAICHUR-PG 765. 1&2	Karnataka (SR)

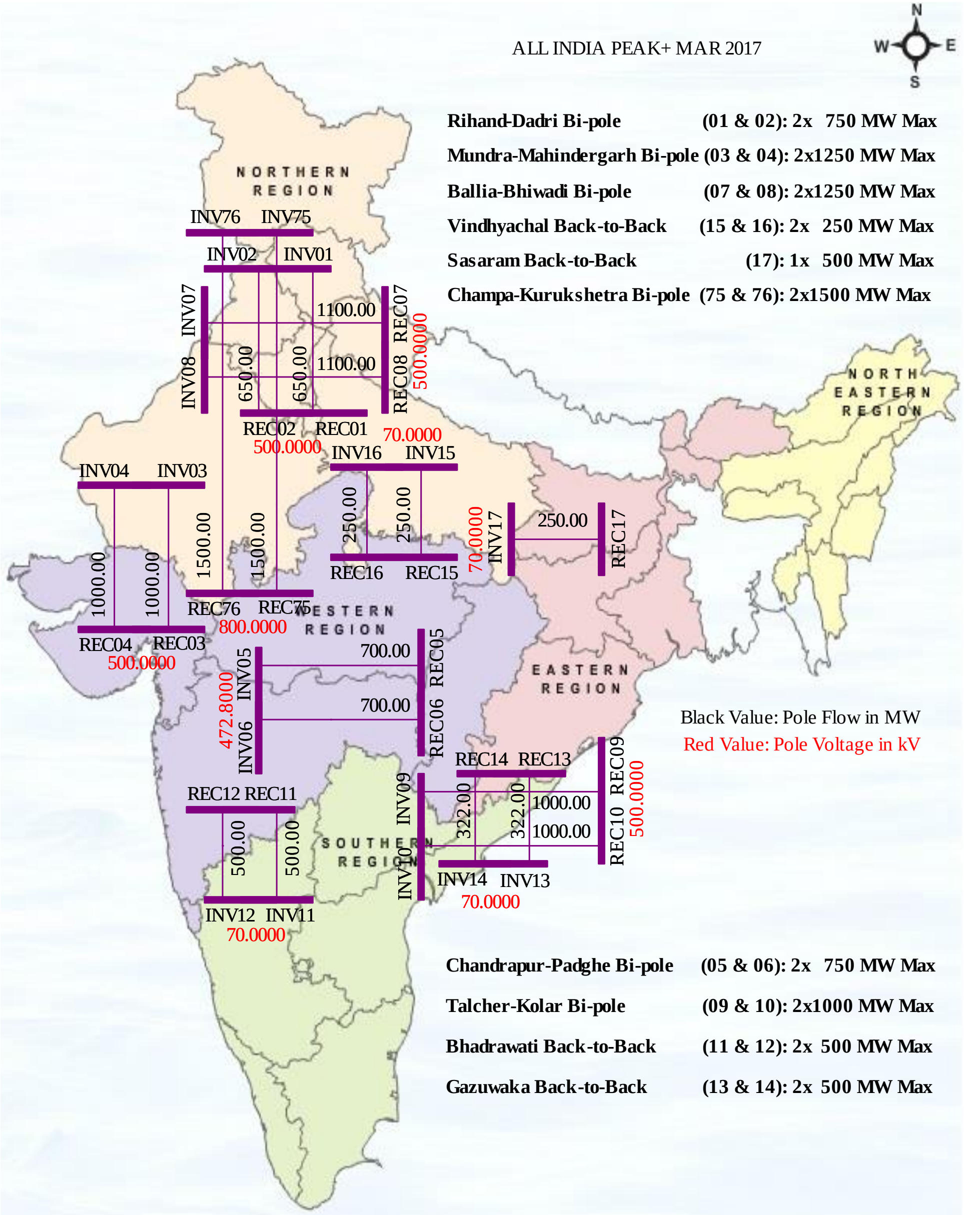
D/C Contingency	SR-Import Voltage Stability Limit (MW) with 2.5% Margin
337004 SHOLAPUR 765. 337005 AURANGABD-PG765. 1&2	6752
337004 SHOLAPUR 765. 437001 RAICHUR-PG 765. 1&2	5224

Mar17 Peak+ TTCs: Initial Loadings & Flows



Powertech

Mar17 Peak+ TTCs: HVDC Schematics



Powertech

Mar17 Peak+ TTCs: HVDC Optimization

- Mundra-Mahindergarh bi-pole flow is maximized to 2x1250 MW along NR-Import transfer
- Vindhyachal back-to-back flow is already at 2x250 MW maximum
- Sasaram back-to-back flow is maximized to 1x500 MW along NR-Import transfer
- Champa-Kurukshetra bi-pole flow is already at 2x1500 MW maximum
- Gazuwaka back-to-back flow is maximized to 2x500 MW along SR-Import transfer
- Talcher-Kolar bi-pole flow is already at 2x1000 MW maximum
- Bhadrawati back-to-back flow is already at 2x500 MW maximum
- Other links are intra-regional and not directly affecting inter-regional TTCs

Mar17 Peak+ TTCs: Violations

- Each violation is registered at its first occurrence

NR-Import MW Limit	Cause	Worst Contingency	Worst Violated Branch/Bus/State
18750	O/L	187706 AGRA-PG 765. 368007 GWALIOR 765. 1/2	187706 AGRA-PG 765. 368007 GWALIOR 765. 2/1
22415	O/L	187706 AGRA-PG 765. 184922 AGRA 400. 1/2	187706 AGRA-PG 765. 184922 AGRA 400. 2/1
22517	O/L	184700 GNOIDA765 765. 187706 AGRA-PG 765. 1	174400 AGRAUP4 400. 184922 AGRA 400. 2
23599	O/L	184462 MAINPURI-PG 400. 184465 FATEHPUR-PG 400. 1	184465 FATEHPUR-PG 400. 184914 MAINPUR_FSC2400. 1
23599	O/L	184465 FATEHPUR-PG 400. 184462 MAINPURI-PG 400. 1	184415 MAINPUR_FSC1400. 184465 FATEHPUR-PG 400. 1
25000	O/L	184462 MAINPURI-PG 400. 184465 FATEHPUR-PG 400. 1	184462 MAINPURI-PG 400. 184914 MAINPUR_FSC2400. 1
25419	O/L	368007 GWALIOR 765. 368012 SATNA 765. 1/2	368007 GWALIOR 765. 368012 SATNA 765. 2/1
27425	O/L	167773 JAIPURR 765. 368007 GWALIOR 765. 1/2	167773 JAIPURR 765. 368007 GWALIOR 765. 2/1
27639	O/L	418008 GAYA 765. 414008 GAYA-PG 400. 1	418008 GAYA 765. 414008 GAYA-PG 400. 2,3
28340	V/C	1 Pole Champa-Kurukshetra HVDC	Madhya Pradesh (WR)

SR-Import MW Limit	Cause	Worst Contingency	Worst Violated Branch/Bus/State
7961	O/L	514005 VIJW 400. 514092 VEMAG-II 400. 1	514006 GAZW 400. 514092 VEMAG-II 400. 1
8261	O/L	378040 SHOLAPUR 765. 528003 RAIC800 765. 1/2	378040 SHOLAPUR 765. 528003 RAIC800 765. 2/1
8412	O/L	514092 VEMAG-II 400. 518092 VEM-II80 765. 1/2	514092 VEMAG-II 400. 518092 VEM-II80 765. 2/1
8463	O/L	378040 SHOLAPUR 765. 378043 AURANGABD-PG765. 1/2	378040 SHOLAPUR 765. 378043 AURANGABD-PG765. 2/1
8920	O/L	534301 MADKTHRA4A 400. 534950 TRICHUR4A 400. @1	534955 KOZIKODE4 400. 532955 KOZHIKOD2 220. 1,2
8972	O/L	374013 KOLHAPUR 400. 374050 KOLHAPURPG 400. 1/2	374013 KOLHAPUR 400. 374050 KOLHAPURPG 400. 2/1
10674	O/L	518028 KURL800 765. 528003 RAIC800 765. 1	518028 KURL800 765. 528003 RAIC800 765. 2
11158	O/L	544002 MADR 400. 544090 SVCHTRM 400. 1	544002 MADR 400. 542002 SPBUDR2 230. 1,2,3
11810	O/L	528003 RAIC800 765. 524013 RAIC-NEW 400. 1/2	528003 RAIC800 765. 524013 RAIC-NEW 400. 2/1
11919	O/L	518028 KURL800 765. 528003 RAIC800 765. 2	518028 KURL800 765. 528003 RAIC800 765. 1
11974	O/L	524007 NELMANG4 400. 524044 HIRY4 400. 1	524044 HIRY4 400. 522044 HIRY 220. 1,2
12250	O/L	374003 LONIKHAND 400. 374042 PUNE-PG-AIS 400. 1	374029 CHAKAN 400. 374042 PUNE-PG-AIS 400. 1
12860	O/L	544013 PUGALUR4 400. 544086 MALEKTT 400. 1	544073 PONDY4 400. 544090 SVCHTRM 400. 1
12973	V/C	378040 SHOLAPUR 765. 528003 RAIC800 765. 1,2	Karnataka (SR)

Mar17 Peak+ TTCs: Voltage Stability Limits

- Voltage stability limits with 5% margin from collapse points
- Worst contingency and State
- TTCs calculated by CTU are dominated by overloads
  - At first, they are based on dc power flow solutions and linear extrapolation of their corresponding distribution factors in the network (approximation)
  - Then, verified using repeated power flows with full ac solutions for the known worst contingencies

Path	Mar17 Peak+ Initial Transfer (MW)			Mar17 Peak+ VS Limit (MW)			CTU TTC (MW)
	From WR	From ER	Total	From WR	From ER	Total	Total
NR-Import	7328	4883	12211	16386	10604	26990	17100
SR-Import	3122	3351	6473	7504	4851	12355	7275

Path	Diverged Contingency in Mar17 Peak+	Worst State
NR-Import	1 Pole Champa-Kurukshetra HVDC	Madhya Pradesh (WR)
SR-Import	378040 SHOLAPUR 765. 528003 RAIC800 765. 1,2	Karnataka (SR)

Mar17 Peak+ TTCs: Thermal Limits

- Overloads of the ac circuits of inter-regional interfaces
  - Occur when one circuit of the indicated Double-Circuit (D/C) line is disconnected causing overloading of the remaining circuit
- TTCs need to be reduced to these values if the corresponding Rate B values are actually the short-term (not continuous) ratings
  - No danger of voltage collapse
  - Intra-regional overloads are to be handled by operators (hence soft limits):
    - Re-connecting relevant out-of-service branches
    - Disconnecting the overloaded branches
    - Re-scheduling HVDC links
    - Re-scheduling generator outputs, etc.

Path	Contingency/Overloaded Interface Circuit	Mar17 Peak+ O/L Limit (MW)		
		From WR	From ER	Total
NR-Import	187706 AGRA-PG 765. 368007 GWALIOR 765. 1/2	11483	7267	18750
SR-Import	378040 SHOLAPUR 765. 528003 RAIC800 765. 1/2	4272	3989	8261

Powertech

Mar17 Peak+ TTCs: NR Required Vs. Calculated

- Initial transfers are snapshots of the required inter-regional capabilities of the existing system
  - TTCs imply meeting these requirements with large margins
- Capabilities may reduce depending on:
  - Long Term Access (LTA)
  - Medium Term Open Access (MTOA)
  - Margin available for Short Term Open Access (STOA)

NR Generation Capacity Status	NR Generation Capacity (MW)	NR Peak Load (MW)	NR-Import Limit (MW)	Margin (MW)	Improvement Required
Initial	54642	55699	18750	17693	No
5% Reduction	51910	55699	18750	14961	No
10% Reduction	49178	55699	18750	12229	No
15% Reduction	46446	55699	18750	9497	No
20% Reduction	43714	55699	18750	6765	No
25% Reduction	40982	55699	18750	4033	No
30% Reduction	38249	55699	18750	1300	No
32.4% Reduction	36949	55699	18750	0	Yes

Mar17 Peak+ TTCs: SR Required Vs. Calculated

SR Generation Capacity Status	SR Generation Capacity (MW)	SR Peak Load (MW)	SR-Import Limit (MW)	Margin (MW)	Improvement Required
Initial	52800	44687	8261	16374	No
5% Reduction	50160	44687	8261	13734	No
10% Reduction	47520	44687	8261	11094	No
15% Reduction	44880	44687	8261	8454	No
20% Reduction	42240	44687	8261	5814	No
25% Reduction	39600	44687	8261	3174	No
30% Reduction	36960	44687	8261	534	No
31% Reduction	36426	44687	8261	0	Yes

- After respectively 32.4% and 31% generation capacity reductions in NR and SR, system improvements are needed
- Since the limits are due to line overloads, increasing the thermal capacity of the involved circuits may be considered through increasing their clearances to the ground or re-conductoring
- Ultimate solution is addition of new transmission lines
  - Also effective for increasing voltage stability limits (& reactive resources)

Powertech

Feb16 Peak & Off-Peak TTCs: Voltage Stability Limits

- Voltage stability limits with 5% margin from collapse points
  - Voltage min/max violations are to be handled by operators (soft limits)
- Based on 2500 MVA Sholapur-Raichur 765 kV circuits rating (4200 MVA in base case) overload limits of WR-SR and SR-Import in the off-peak case are **3980** MW and **6616** MW
  - No danger of voltage collapse
  - Intra-regional overloads are to be handled by operators (soft limits)
- TTCs calculated by NLDC are dominated by overloads

Path	Initial Transfer (MW)		TTC (MW)		
	Feb16 Peak	Feb16 Off-Peak	Feb16 Peak	Feb16 Off-Peak	Feb16 NLDC
NR-WR	1990	2594	2468	5914	2500
WR-NR	5504	4919	7332	7404	7450
NR-ER	4060	2677	4025	4152	2000
ER-NR	830	1115	2192	2767	4800
WR-SR	1908	2034	3097	**5422**	3000
ER-SR	2700	2650	2714	2571	2650
ER-NER	-91	-139	728	679	1390
NER-ER	1590	1190	1608	1472	1220
NR-Import	6334	6034	8650	9114	9950
SR-Import	4608	4684	5664	**7957**	5650
NR-Export	2440	2703	3532	7236	3800

Feb16 Peak & Off-Peak TTCs: Worst Contingencies

Path	Diverged Contingency in Feb16 Peak	Worst State for Voltage Collapse
NR-WR	314008 VAPI 400. 314010 SUGEN 400. 1	Gujarat (WR)
WR-NR	Pre-Contingency	Rajasthan (NR)
NR-ER	214003 MUZZAFARPUR4400. 212012 MUZZAFARPUR2220. 1	Bihar (ER)
ER-NR	Pre-Contingency	Uttar Pradesh (NR)
WR-SR	444004 MYWADI 400. 454005 PALAKD 400. 1	Andhra Pradesh (SR)
ER-SR	254010 JEYPORE4 400. 254025 JP_GZW_HVDC 400. 1	Orissa (ER)
ER-NER	574001 PALATANA4 400. 571001 PALATANA1 132. 1	Tripura (NER)
NER-ER	None	None
NR-Import	Pre-Contingency	Rajasthan (NR)
SR-Import	444004 MYWADI 400. 454005 PALAKD 400. 1	Andhra Pradesh (SR)
NR-Export	314008 VAPI 400. 314010 SUGEN 400. 1	Gujarat (WR)

Path	Diverged Contingency in Feb16 Off-Peak	Worst State for Voltage Collapse
NR-WR	334058 KOLHAPUR-PG 400. 344001 MAPUSA 400. 1	Maharashtra (WR)
WR-NR	154000 AGRAUP4 400. 152004 AGRAN2 220. 1 (and Pre-Contingency Right Afterwards)	Rajasthan (NR)
NR-ER	252023 MENDHASAL2 220. 254005 MENDHASAL 400. 1	Orissa (ER)
ER-NR	154000 AGRAUP4 400. 152004 AGRAN2 220. 1 (and Pre-Contingency Right Afterwards)	Rajasthan (NR)
WR-SR	444020 METR-III 400. 1	Andhra Pradesh (SR)
ER-SR	254010 JEYPORE4 400. 254020 BOLANGIR 400. 1	Orissa (ER)
ER-NER	524009 SILCHAR4 400. 574001 PALATANA4 400. 1	Tripura (NER)
NER-ER	254014 ANGUL4 400. 254020 BOLANGIR 400. 1	Orissa (ER)
NR-Import	154000 AGRAUP4 400. 152004 AGRAN2 220. 1 (and Pre-Contingency Right Afterwards)	Rajasthan (NR)
SR-Import	444020 METR-III 400. 1	Andhra Pradesh (SR)
NR-Export	214000 BIHARSHARIF 400. 214002 PURNEA4 400. A	Bihar (ER)

Powertech

Feb16 Peak & Off-Peak TTCs: Parallel Path Flows

- For WR-NR transfers, the change occurring in WR-ER flow cannot be avoided unless there is some source sharing by ER
- For ER-NR transfers, the change occurring in WR-ER flow cannot be avoided unless there is some source sharing by WR
- For ER-NER peak/off-peak transfers, up to about 200/230 MW flow increase from ER to WR (coming back from NR to ER) is possible
  - To avoid this parallel path flow, the source of transfer should include about 25% WR sharing
- For NR-Import the change occurring in WR-ER flow cannot be avoided unless the source sharing by ER is reduced

Feb16 Peak & Off-Peak TTCs: State-wise Transfers

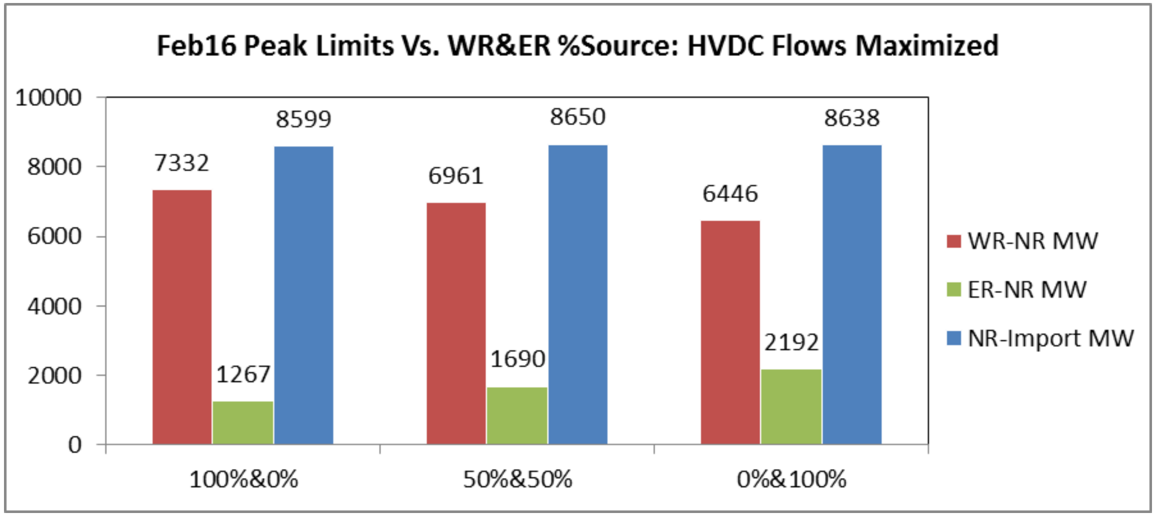
Region	State	Absorption TTC (MW)		Injection TTC (MW)	
		Feb16 Peak	Feb16 Off-Peak	Feb16 Peak	Feb16 Off-Peak
NR	Punjab	10172	10730	5136	3478
	Haryana	10617	9760	6105	6105
	Rajasthan	10150	10110	8691	11424
	Delhi	5414	5725	2747	2747
	Uttar Pradesh	13881	13777	7314	7889
	Uttarkhand	2290	2539	3119	3119
	Himachal Pradesh	2271	2489	8112	8930
	Jammu & Kashmir	2432	2198	2441	2535
	Chandigarh	608	684	0	0
WR	Gujarat	13950	13779	14684	14431
	Madhya Pradesh	9377	9911	13825	14213
	Maharasthra	18985	16969	17124	13662
	Goa	732	329	0	0
	Chhattisgarh	3552	3637	11967	14875
	Daman & Diu	558	726	0	0
	Dadra & Nagar Haveli	1039	1283	0	0
ER	Bihar	2961	2620	1748	1962
	Jharkhand	1395	1478	2267	1376
	Damodar Valley Corp.	3018	3065	4005	2843
	Orissa	3288	2282	3381	3272
	West Bengal	6786	6682	5187	3503
	Sikkim	342	272	0	0
SR	Telangana	7131	7172	6380	8399
	Andhra Pradesh	8853	8870	5476	7301
	Karnataka	8826	8736	7285	8573
	Tamil Nadu	12591	12735	14162	15556
	Kerala	3638	3099	2696	2696
NER	Arunachal Pradesh	269	278	0	0
	Assam	955	866	596	449
	Manipur	315	300	33	33
	Meghalaya	449	520	145	87
	Mizoram	135	119	0	0
	Nagaland	277	267	39	15
	Tripura	321	235	922	922

Green limits are due to maximum generation availability (may be exceeded)

Powertech

Feb16 Peak & Off-Peak TTCs: Import to NR Trend

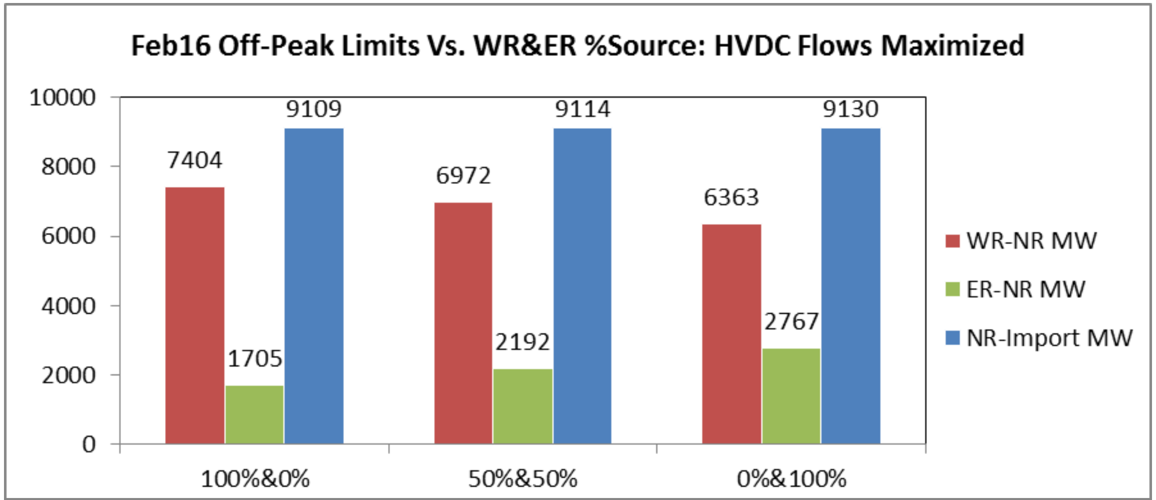
- NR import is virtually independent of source sharing
  - WR-NR reduction is picked up by ER-NR and vice versa
- Peak/off-peak limit levels remain the same, as long as:
  - Transfer pattern remains the same,
  - The critical contingency remains the same,
  - And inter-regional HVDC flows are maximized
- No need for two-dimensional transfer analysis (nomograms)

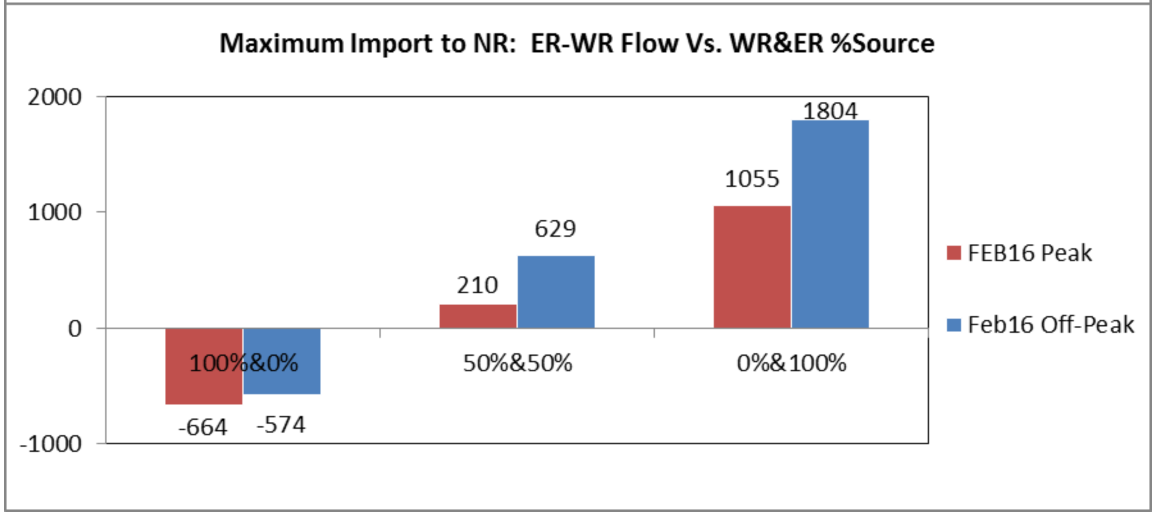


Powertech

Feb16 Peak & Off-Peak TTCs: Import to NR Trend

- Different ER-WR flow in the base cases means different level of NR import limit, while the same trend remains

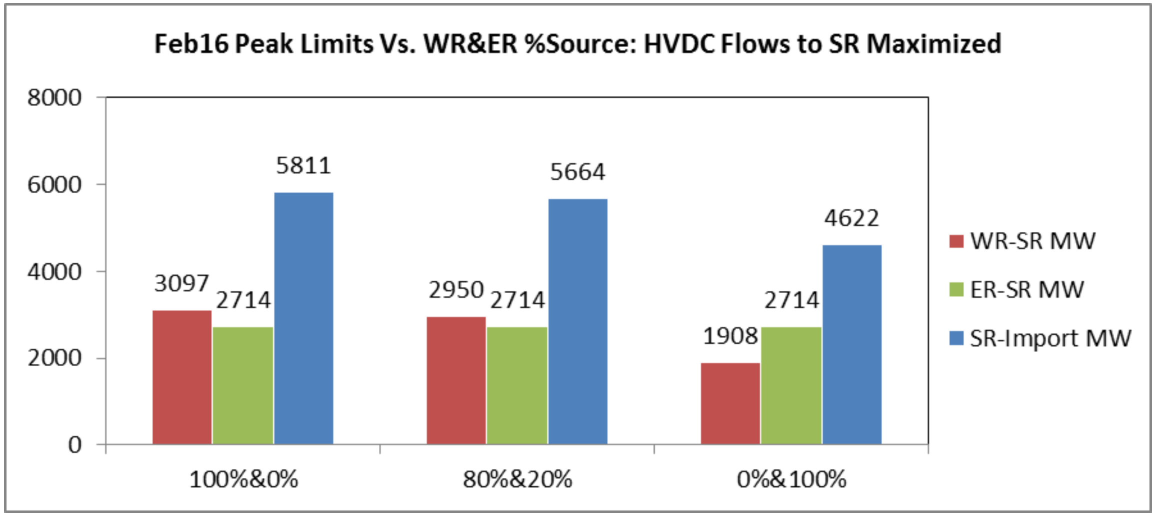




Powertech

Feb16 Peak & Off-Peak TTCs: Import to SR Trend

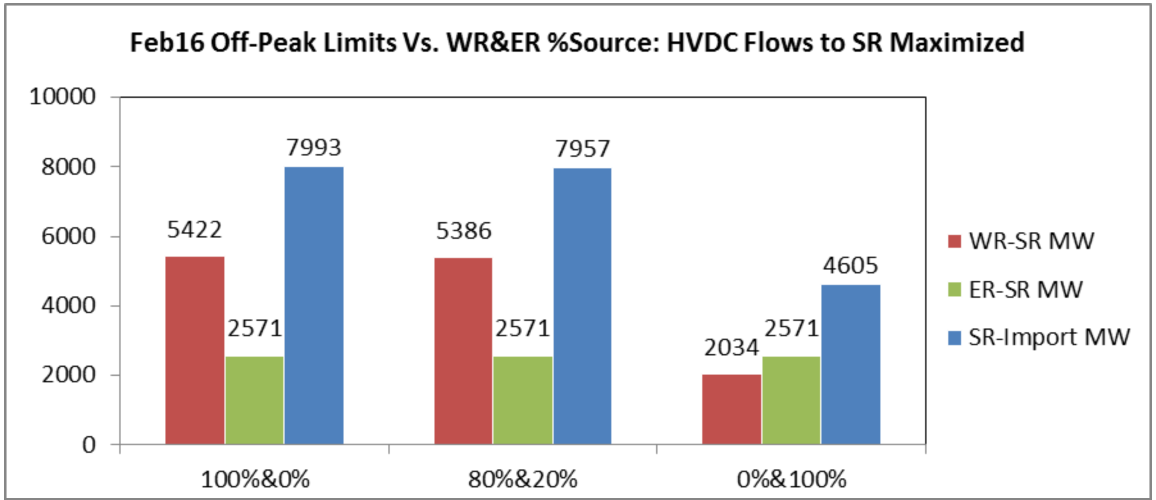
- SR import relationship to source sharing is almost linear
  - ER-SR limit is constant (HVDC only): Avoid extreme ER source sharing
- Peak/off-peak limit equations remain the same, as long as:
  - Transfer pattern remains the same,
  - The critical contingency remains the same,
  - And inter-regional HVDC flows are maximized
- No need for two-dimensional transfer analysis (nomograms)

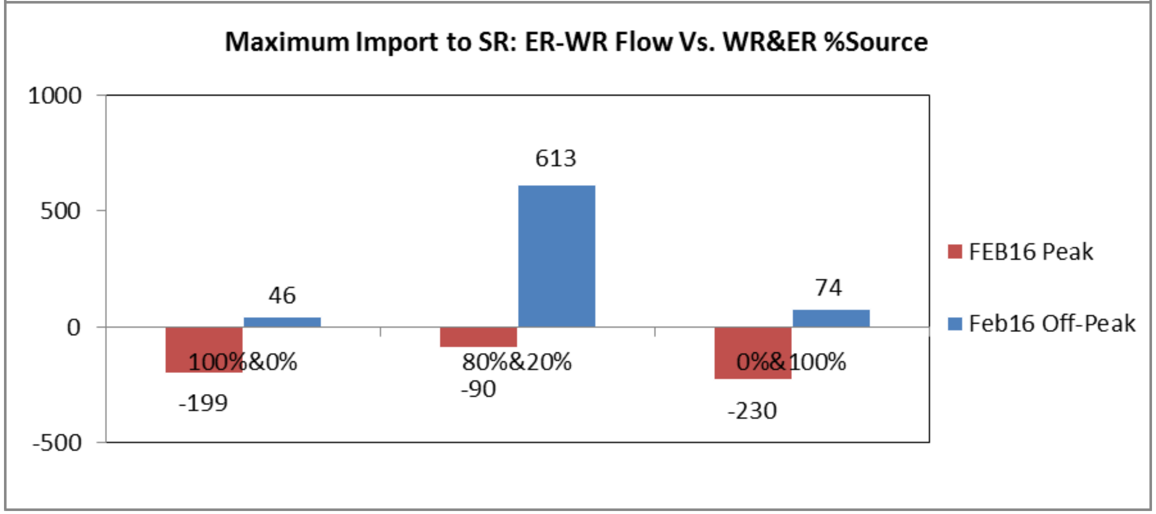


Powertech

Feb16 Peak & Off-Peak TTCs: Import to SR Trend

- Different ER-WR flow in the base cases means different equations for SR import limit, while the same trend remains





Powertech

Feb16 Peak & Off-Peak TTCs: Dynamic Studies

- Small-signal stability is analyzed using SSAT
  - Three inter-area modes found with < 10% damping ratio
  - Damping ratios do not reduce much after single contingencies
- For transient situations, TSAT is used to simulate all single contingencies at base cases & at VS limits of forward transfers
  - 5-cycle 3-phase faults of ≥ 400 kV including ICTs
  - Disconnection of large generators and HVDC poles
  - Maximum peak-peak rotor angle varied from 78.1° to 92.2° (<< 120°)
  - Prony Analysis results indicated no critical damping issue

Mode # (SSAT)	Frequency (Hz)		Damping (%)		Most Dominant Unit	Feb16 Peak Mode Description
	Peak	Off-Peak	Peak	Off-Peak		
1	0.65	0.67	9.6	9.9	314035 CGPL 400. 2	Inter-area mode from WR on one side to NER, SR, and NR on the other
2	0.72	0.74	7.9	8.6	444017 KKNPP 400. 1	Inter-area mode from SR on one side to ER on the other (through WR)
3	0.91	0.90	7.7	8.5	154057 RIHAND-G400. 2	Inter-area mode from NER on one side to NR on the other (through ER)

Mar17 Peak & Off-Peak TTCs: Voltage Stability Limits

- Voltage stability limits with 5% margin from collapse point
  - Voltage min/max violations are to be handled by operators (soft limits)
- TTCs calculated by CTU are dominated by overloads

Path	Initial Transfer (MW)		TTC (MW)		
	Mar17 Peak	Mar17 Off-Peak	Mar17 Peak	Mar17 Off-Peak	Mar17 CTU
NR-WR	4432	4979	8940	12330	-
WR-NR	7559	8046	11886	13421	12279
NR-ER	2178	2839	3973	6410	-
ER-NR	4955	5148	8583	8690	4217
WR-SR	3131	3145	7539	8170	3699
ER-SR	3341	3235	4743	4713	3419
ER-NER	213	-357	1761	1515	1976
NER-ER	2368	2146	2821	2506	-
NR-Import	12514	13194	18512	20660	16496
SR-Import	6472	6380	12072	12643	7118
NR-Export	554	1439	7152	12222	-

Powertech

Mar17 Peak & Off-Peak TTCs: Worst Contingencies

Path	Diverged Contingency in Mar17 Peak	Worst State for Voltage Collapse
NR-WR	1 Pole Chandrapur-Padghe HVDC	Maharashtra (WR)
WR-NR	1 Pole Champa-Kurukshetra HVDC	Rajasthan (NR)
NR-ER	434016 BIDHAN NAGAR400. 444030 ARAMBG 400. 1	West Bengal (ER)
ER-NR	1 Pole Champa-Kurukshetra HVDC	Rajasthan (NR)
WR-SR	378040 SHOLAPUR 765. 528003 RAIC800 765. 1	Karnataka (SR)
ER-SR	1 Pole Talcher-Kolar HVDC	Maharashtra (WR)
ER-NER	214321 AZARA 400. 234020 BYRNIHAT 400. 1	Meghalaya (NER)
NER-ER	None	None
NR-Import	1 Pole Champa-Kurukshetra HVDC	Rajasthan (NR)
SR-Import	378040 SHOLAPUR 765. 528003 RAIC800 765. 1	Karnataka (SR)
NR-Export	434016 BIDHAN NAGAR400. 444030 ARAMBG 400. 1	West Bengal (ER)

Path	Diverged Contingency in Mar17 Off-Peak	Worst State for Voltage Collapse
NR-WR	None	None
WR-NR	1 Pole Champa-Kurukshetra HVDC	Rajasthan (NR)
NR-ER	434016 BIDHAN NAGAR400. 444030 ARAMBG 400. 1	West Bengal (ER)
ER-NR	None	None
WR-SR	378040 SHOLAPUR 765. 528003 RAIC800 765. 1	Karnataka (SR)
ER-SR	None	None
ER-NER	214030 BALIPARA-PG 400. 214170 BONGAIGAON 400. 1	Assam (NER)
NER-ER	None	None
NR-Import	1 Pole Champa-Kurukshetra HVDC	Rajasthan (NR)
SR-Import	378040 SHOLAPUR 765. 528003 RAIC800 765. 1	Maharashtra (WR)
NR-Export	None	None

Mar17 Peak & Off-Peak TTCs: Thermal Limits

- Overloads of inter-regional interface ac circuits
- TTCs need to be reduced to these values if the corresponding Rate B values are actually the short-term (not continuous) ratings
  - No danger of voltage collapse
  - Intra-regional overloads are to be handled by operators (soft limits)

Path	Contingency/Overloaded Interface Circuit	Mar17 Limit (MW)	
		Peak	Off-Peak
WR-NR	187706 AGRA-PG 765. 368007 GWALIOR 765. 1/2	10751	12030
WR-SR	378040 SHOLAPUR 765. 528003 RAIC800 765. 1/2	4317	4403
ER-SR	378040 SHOLAPUR 765. 528003 RAIC800 765. 1/2	4015	3914
NR-Import	187706 AGRA-PG 765. 368007 GWALIOR 765. 1/2	18429	20415
SR-Import	378040 SHOLAPUR 765. 528003 RAIC800 765. 1/2	7392	8210

Mar17 Peak & Off-Peak TTCs: Parallel Path Flows

- For WR-NR transfer, up to ~190 MW flow increase from WR to SR is possible
  - This is insignificant and may be ignored
  - The change occurring in ER-WR flow cannot be avoided without some source sharing by ER
- For ER-NR transfer, up to ~170 MW flow increase from ER to SR is possible
  - This is insignificant and may be ignored
  - The change occurring in ER-WR flow cannot be avoided without some source sharing by WR
- For WR-SR transfer, up to ~160 MW flow increase from WR to NR is possible
  - This is insignificant and may be ignored
- For ER-SR transfer, up to ~1460 MW flow increase from ER to NR is possible
  - This is quite significant and may be avoided by about 90% source sharing of WR (similar to SR-Import transfer indicated below)
- For ER-NER transfer, up to ~300 MW flow increase from ER to WR is possible
  - To avoid this parallel path flow, the source of transfer should include WR up to the indicated flow amount (i.e., about 15% WR sharing)
- For NR-Import transfer, there is no change in the flows to SR
  - This indicates that the 50%&50% sharing of WR&ER sources is about optimum in this respect
  - The change occurring in ER-WR flow cannot be avoided unless source sharing by ER is reduced
- For SR-Import transfer, up to ~150 MW flow increase from ER to NR is possible
  - This indicates that the optimum source sharing by ER is even less than the suggested 20%; it is rather around 10% (0% sharing causes 160 MW loop flow in the opposite direction)
  - Without phase shifter you are left with HVDC control for loop flow control, other than source sharing

Mar17 Peak & Off-Peak TTCs: State-wise Transfers

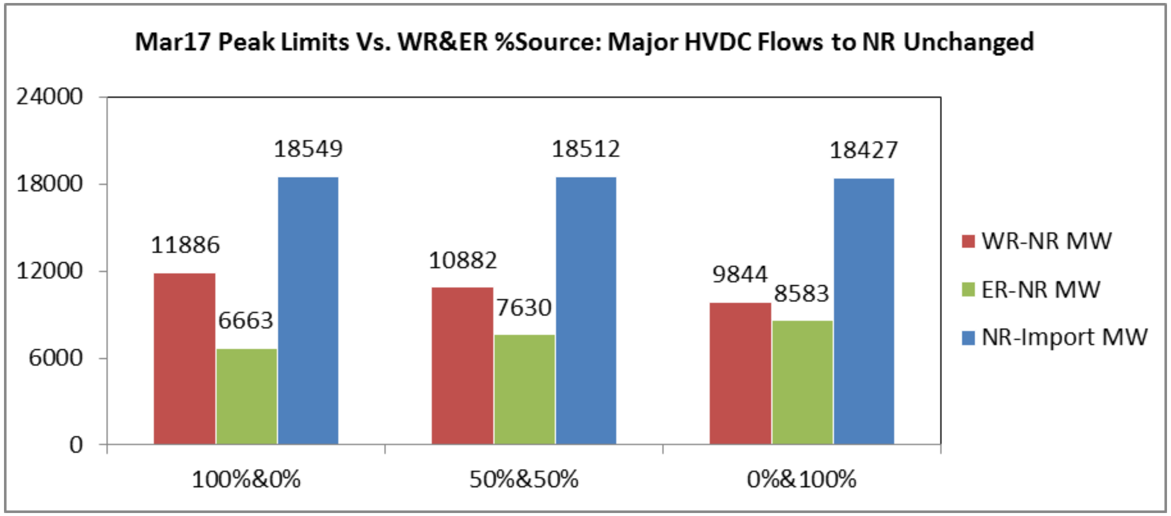
Region	State	Absorption TTC (MW)		Injection TTC (MW)	
		Mar17 Peak	Mar17 Off-Peak	Mar17 Peak	Mar17 Off-Peak
NR	Punjab	13691	11583	8216	8216
	Haryana	12708	11998	6255	6255
	Rajasthan	12217	11133	11510	11320
	Delhi	8573	8082	2811	2811
	Uttar Pradesh	18876	10252	21854	20957
	Uttarkhand	3258	3013	3244	3244
	Himachal Pradesh	2929	2693	9389	8870
	Jammu & Kashmir	3450	2650	2663	2496
	Chandigarh	742	783	0	0
WR	Gujarat	17279	14895	18996	21027
	Madhya Pradesh	11664	10842	19997	19939
	Maharasthra	23689	20403	25840	25392
	Goa	1562	1578	0	0
	Chhattisgarh	3832	3816	23853	24694
	Daman & Diu	584	555	0	0
	Dadra & Nagar Haveli	1666	1513	12	12
ER	Bihar	6444	6423	6874	7571
	Jharkhand	2324	2349	2559	2559
	Damodar Valley Corp.	4651	4682	8933	8933
	Orissa	5587	5528	10517	11174
	West Bengal	9050	8010	10061	10061
	Sikkim	907	890	2085	2089
SR	Telangana	12018	9037	8183	8183
	Andhra Pradesh	15203	12064	14511	14511
	Karnataka	14753	13066	10638	10638
	Tamil Nadu	17796	15871	18757	19311
	Kerala	4770	4431	2710	2707
NER	Arunachal Pradesh	117	125	386	386
	Assam	1876	1258	1596	1596
	Manipur	519	480	100	100
	Meghalaya	717	655	348	348
	Mizoram	850	639	0	0
	Nagaland	338	307	94	94
	Tripura	871	699	1017	1017

Green limits are due to maximum generation availability (may be exceeded)

Powertech

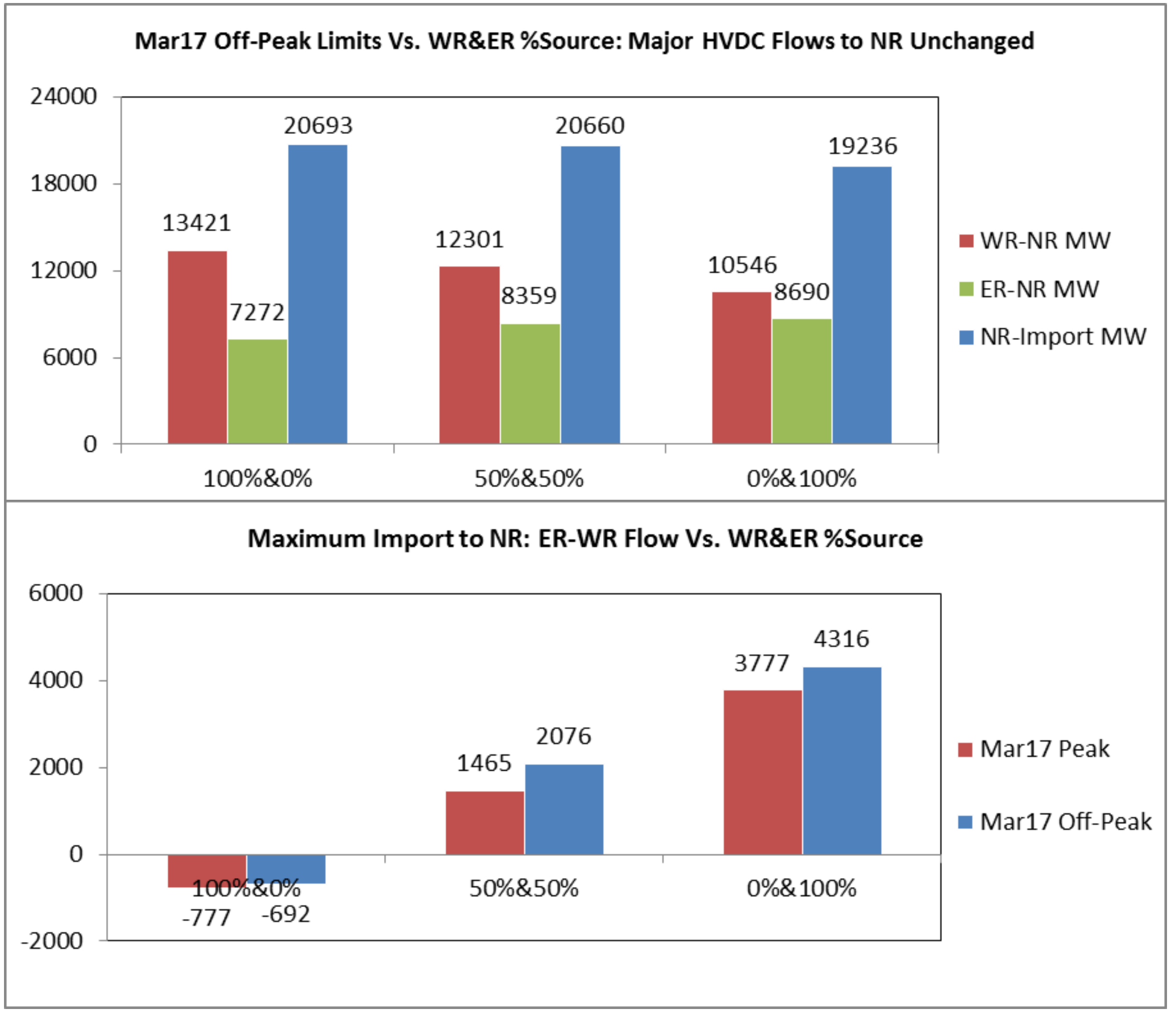
Mar17 Peak & Off-Peak TTCs: Import to NR Trend

- NR import slightly decreases as WR source share decreases
  - May be conservatively approximated by a linear equation
- Peak/off-peak limit equations remain the same, as long as:
  - Transfer pattern remains the same,
  - The critical contingency remains the same,
  - And inter-regional HVDC flows are the same (close to maximum)
- No need for two-dimensional transfer analysis (nomograms)



Mar17 Peak & Off-Peak TTCs: Import to NR Trend

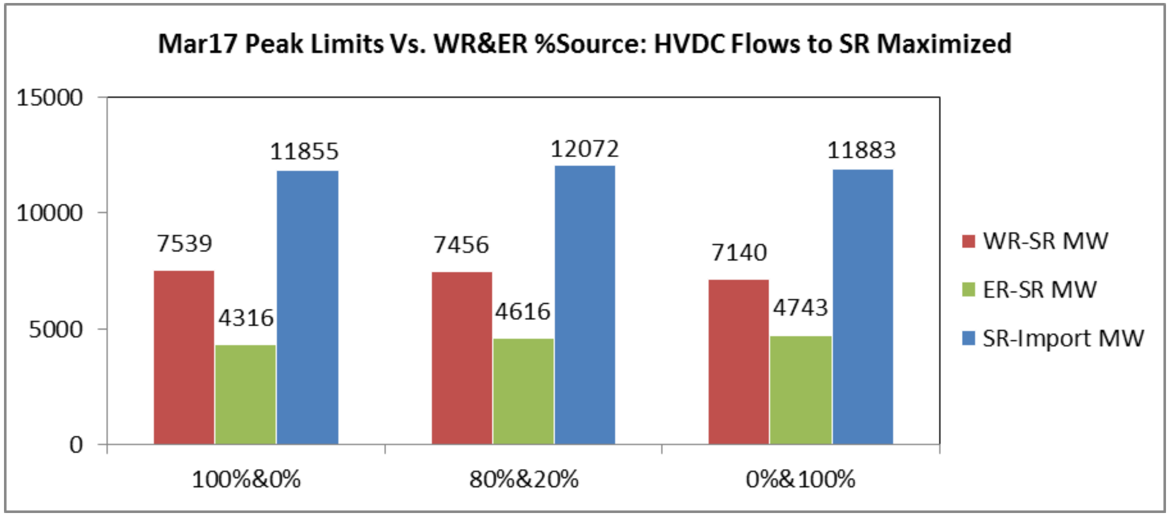
- Different ER-WR flow in the base cases means different equations for NR import limit, while the same trend remains



Powertech

Mar17 Peak & Off-Peak TTCs: Import to SR Trend

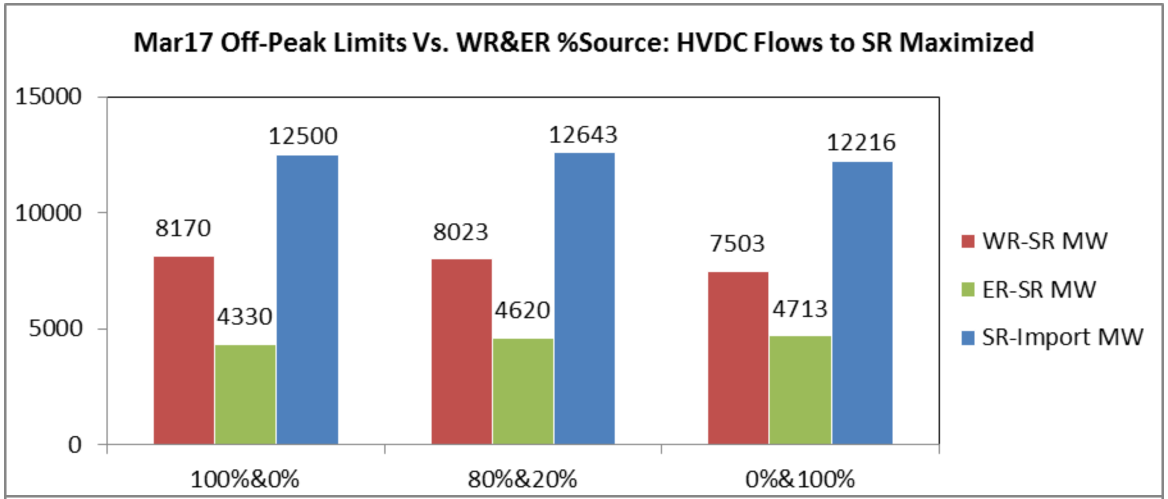
- SR import relationship to source sharing is almost linear
  - ER-SR ac interface is limited: Avoid extreme ER source sharing
- Peak/off-peak limit equations remain the same, as long as:
  - Transfer pattern remains the same,
  - The critical contingency remains the same,
  - And inter-regional HVDC flows are maximized
- No need for two-dimensional transfer analysis (nomograms)

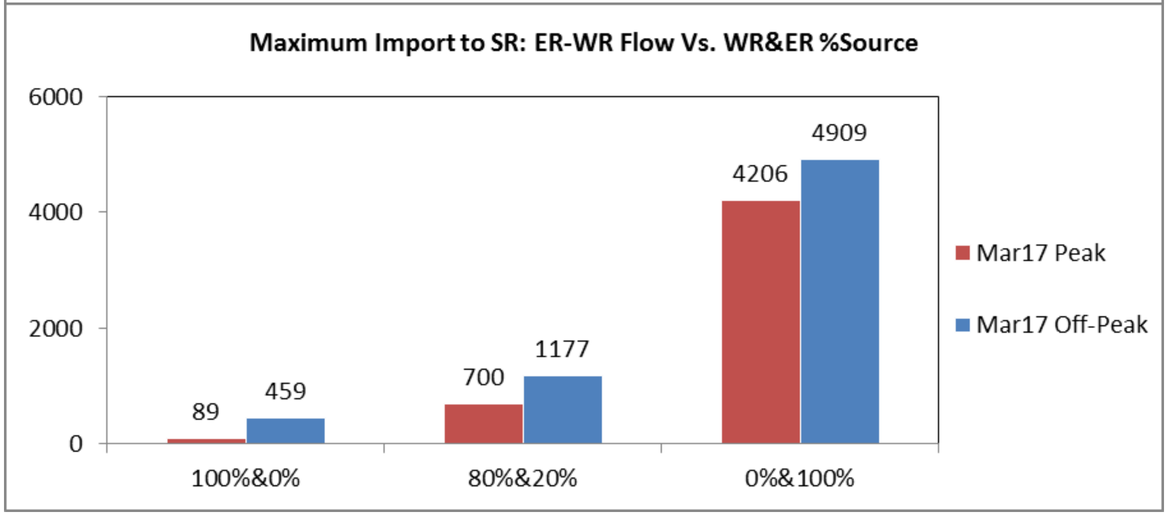


Powertech

Mar17 Peak & Off-Peak TTCs: Import to SR Trend

- Different ER-WR flow in the base cases means different equations for SR import limit, while the same trend remains





Powertech

Mar17 Peak & Off-Peak TTCs: Dynamic Studies

- Small-signal stability is analyzed using SSAT
  - Two inter-area modes found with < 10% damping ratio
  - Damping ratios do not reduce much after single contingencies
- For transient situations, TSAT is used to simulate all single contingencies at base cases & at VS limits of forward transfers
  - 5-cycle 3-phase faults of $\geq$ 400 kV including ICTs
  - Disconnection of large generators and HVDC poles
  - Maximum peak-peak rotor angle varied from 80.5° to 98.6° (<< 120°)
  - Prony Analysis results indicated no critical damping issue

Mode #	Frequency (Hz)		Damping (%)		Most Dominant Unit	Mar17 Peak Mode Description
	Peak	Off-Peak	Peak	Off-Peak		
1	0.86	0.87	7.7	8.9	422002 BALIMELA220. 8 or 422002 BALIMELA220. 7	Inter-area mode from ER and NR on one side to WR on the other
2	0.91	0.90	8.7	8.7	522012 KAIG 220. 2 or 512050 LISLRU 220. 4	Inter-area mode from SR on one side to WR on the other

Powertech

Conclusions: Computational Methodology

- Voltage stability margin was applied through PV analysis (VSAT)
- Stressed the system with transfers under credible contingencies, while appropriate criteria were applied
  - Single contingencies consisted of appropriate generators, HVDC poles, ac lines/transformers connected to ≥ 400 kV buses focusing on ISTS
  - Merit order of ISGS was applied as much as available
  - Focused on interface overloads and voltage collapses
- Feb16 peak and off-peak (POSOCO)
  - Data issues led to Feb16 peak+
- Mar17 peak and off-peak (CTU)
  - Data issues led to Mar17 peak+
- Maximized inter-regional HVDC flows as much as possible

Transfer ID	Transfer Type (Source-Sink)	Simultaneous Source Regions	Sink Region
NR-Import	Generation Increase-Generation Decrease	WR & ER (70% & 30%)	NR
SR-Import	Generation Increase-Generation Decrease	WR & ER (80% & 20%)	SR

Powertech

Conclusions: Overall Limits

- Voltage stability limits with 5% margin & interface overload limits
  - Intra-regional overloads registered for information (soft limits)
- More detailed analyses of all inter-regional & State-wise transfers were performed for the earlier cases along with sensitivity studies
  - Dynamic situation was also analyzed from transient and small-signal stability points of view
    - All calculated limits were beyond their corresponding voltage security limits

Case	Path	Initial Transfer (MW)			Voltage Stability Limit (MW)		
		From WR	From ER	Total	From WR	From ER	Total
Feb16 Peak+	NR-Import	6766	1545	8311	12403	4526	16929
	SR-Import	2551	2650	5201	6200	2650	8850
Mar17 peak+	NR-Import	7328	4883	12211	16386	10604	26990
	SR-Import	3122	3351	6473	7504	4851	12355

Case	Path	Contingency/Overloaded Interface Circuit	Total O/L Limit (MW)
Feb16 Peak+	NR-Import	157007 AGRA-PG 765. 327003 GWALIOR 765. 1/2	9697
	SR-Import	337004 SHOLAPUR 765. 437001 RAICHUR-PG 765. 1/2	6409
Mar17 peak+	NR-Import	187706 AGRA-PG 765. 368007 GWALIOR 765. 1/2	18750
	SR-Import	378040 SHOLAPUR 765. 528003 RAIC800 765. 1/2	8261

Conclusions: Model Improvements

- Basic recommendations for model improvements were provided in this task as practiced in most North American utilities
  - More detailed suggestions in the Final Reports of Tasks I and V
- Forming suitable study committees involving all related entities
  - Collecting data
  - Reviewing the collected data
  - Validating the existing and future models
  - Unification of modelling practices for POSOCO and CTU:
    - Facilitates creation of suitable base cases
    - Facilitates creation of a common data base
    - Facilitates study results comparisons
- Once the models are sufficiently improved, a gradual shift to full voltage security analysis is recommended
  - In the meantime, POSOCO and CTU may continue on their current method which is more oriented toward paths thermal limitations at $\geq$ 400 kV

Conclusions: Consolidated Recommendations

- PV analysis with merit orders and suitable margins
- Transient stability simulations combined with small-signal analysis
- Generators with explicit GSU and station load models
- Loads at delivery points with ULTCs, explicit capacitors & dynamics
- Shunts modelled as switchable (manual, slow, and fast)
- Identical numbering/naming in CTU & POSOCO cases (& STUs)
- Dynamic data submissions by facility owners, including sufficient details for HVDC & FACTS to reflect actual system performance
- Data & model validations (down to 20 MVA units)
- A common database & automatically generated base cases
- Committees consisting of all players (CEA, CTU, POSOCO, STUs) for discussions on data requirements, model updates, criteria, etc.

Powertech

The Power of Trust. **The Future of Energy.**

Consultancy Contract to Review Transmission System Transfer Capability and Review of Operational and Long Term Planning (Pkg B)

Zhihong Feng and Saeed Arabi

February 16, 2018

Project Tasks

- Task I: Examination and recommendation of methodology for optimum calculation of transfer capability in the planning and the operational horizons
- Task II: Calculation of transfer capability for the entire country
- **Task III: Guidelines for developing and implementing System Protection Schemes (SPSs) and islanding schemes, and review of existing schemes**
- Task IV: Operational planning and long term planning for secure and efficient operation of the grid
- Task V: Suitable suggestions in the Regulatory framework to ensure secure and efficient grid operation
- Task VI: Review of the tuning of all power electronic devices and suggesting retuning of setting of these devices, as per "Taskforce Report on Power System Analysis"

Task III Specifics

- **Guidelines to formulate proposals** for SPSs and islanding schemes
- **Pre-requisites for successful operation** of islanding schemes and necessary actions for ensuring effective restoration
- **Review of existing** SPSs and islanding schemes
- **Review of interoperability** of existing SPSs in the same area and providing related recommendations
- **Identification of system separation locations** and additionally required schemes

Powertech

Study Modelling

- Study focus is on the existing system
  - Feb16 peak and off-peak cases (POSOCO) of Task II
- Near-term planning system is used for comparison
  - Mar17 peak and off-peak cases (CTU) of Task II
- Main type of study is transient stability simulations
  - Load shedding relay models are developed and added to Task II dynamic data
  - Under-frequency and over-frequency tripping of generators are typically below 47.5 Hz and above 51.5 Hz
  - Typical settings of the over-voltage relays are 110% with 5 seconds delay and 140% instantaneous

Powertech

Study Modelling: Load Shedding Relays

- Four blocks of Under-Frequency Load-Shedding (UFLS) relays modelled using LDS3XX:
  - 49.2, 49.0, 48.8, and 48.6 Hz triggering thresholds in all 5 regions
- Three blocks of rate of change of frequency (df/dt) relays modelled using DLSHXX:
  - 49.9 Hz & 0.1 Hz/s, 49.9 Hz & 0.2 Hz/s, and 49.9 Hz & 0.3 Hz/s in NR & WR
  - 49.5 Hz & 0.2 Hz/s, 49.3 Hz & 0.2 Hz/s, and 49.3 Hz & 0.3 Hz/s in SR
  - None in ER and NER
- Area-wise for Feb16 and Zone-wise for Mar17 (XX=AR and ZN)
  - Distributed uniformly throughout each Area/Zone
  - Feb16 peak loading used as base for setting the fractions
  - 0.1 s (5 cycles) typical relay pickup time
  - 0.1 s (5 cycles) typical breaker delay time

Guidelines: Formulate Proposals – Information Sheet

- Coordination with other protection and control systems
- Reporting any change prior to placing the scheme into service

Item	Information Explanation
Reporting Party	Transmission Owner/System Operator; if not, Generator Owner; if not, Distribution Provider.
Scheme's Name	The name by which the Reporting Party references the scheme.
Classification	i) SPS related to tripping of critical line/corridor. ii) SPS related to safe evacuation of generation. iii) SPS related to overloading of transformers. iv) SPS related to N-E-W and SR grid synchronisation. v) Under-frequency, over-frequency, df/dt, under-voltage, over-voltage, and disturbance-based (or any combination) islanding.
Reference No.	A number for short reference.
Operating Procedure	The identifying procedure number or title (None or N/A as default).
Design Objectives	Data required for describing Design Objectives (contingencies and system conditions for which the scheme was designed).
Operation	Data required for describing Operation (actions taken by the scheme in response to disturbance conditions).
Modelling	Data required for adequate Modelling (information on detection logic or relay settings that control operation of the scheme).
Original In-Service Year	The year that the scheme originally went into service (not subsequent changes).
Recent Assessment Group	The group that performed the most recent assessment of the scheme operation, coordination, and effectiveness.
Recent Assessment Date	The date of the above assessment (mm/yyyy).

Guidelines: Formulate Proposals – Assessment

- Power-flow studies
- Short-circuit and protection coordination studies
- Stability studies
- Island requirements and planning (including load and generator issues)
- Main system requirements and planning (grounding scheme, voltage and frequency regulations, etc.)

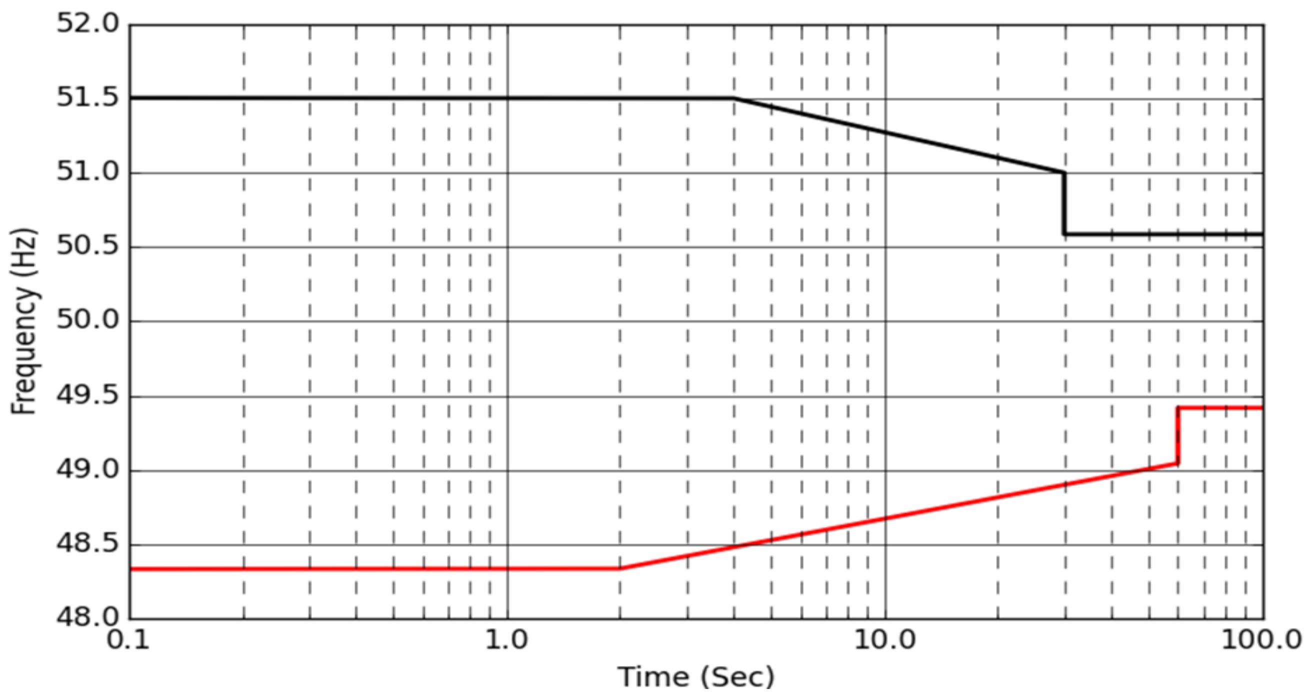
Item (Assessment Summary)	Information Explanation
Reporting Party	The same as that of Information Sheet.
Scheme's Name	The same as that of Information Sheet.
Group Conducting this Scheme Assessment	
Assessment Date	
Review of the Purpose and Impact of the Scheme	Its proper classification, necessity, serving the intended purposes, and meeting performance requirements.
This Scheme Assessment Included the Following:	
• Study Years	
• System Conditions	
• Analyzed Contingencies	Select N-1, N-1-1, N-2, and/or Extreme.
Date of the Technical Studies Completion	
Compliance of the Scheme with Transmission Planning Criteria	Yes or No.
Discussion of Any Coordination Problems Found Between This Scheme and Other Protection and Control Systems During This Assessment	
Proposed Corrective Action Plan If This Scheme Was Found to Be Non-Compliant or Had Coordination Problems During This Assessment	Not Applicable (N/A) if this is the initial assessment.

Guidelines: Island Operation Concerns

- Risk of out-of-phase reconnection at connection points
- Possible equipment damage due to voltage/frequency aberrations
- Adequate and reliable generation
- Reduced system reliability due to increased system complexity
- Safety for general public, emergency personnel, & operators
- Possible reduction in power quality
- Significant changes in fault duty between normal & island modes
- System protection coordination
- Coordination with load-shedding schemes
- Voltage & frequency regulation
- Load (phase) imbalance
- Load and generation matching

Guidelines: Islanding Frequency Regulation

- Essential pre-requisite is capability to balance load & generation
  - Load shedding for resource-deficient islands (typically ≤ 25% imbalance)
  - Generation tripping for islands with surplus of resource
- Adapting NERC criteria to Indian system as below (60 Hz → 50 Hz)
  - Avoid generator under-frequency/over-frequency protections activations



Powertech

Guidelines: Review of Proposals

- Major occasions for review of SPSs and islanding schemes:
  - Prior to initial installation and commissioning
  - Before significant modifications or extensions with possible impact to reliability or the intent of the scheme
  - In the event of failure of a scheme for which significant modifications will be necessary
  - Removal of a scheme from service
  - Due for a periodic review (every 5 years is recommended)
- Relevant checklist was developed
  - Utilized to review all existing schemes to the extent possible
  - No information was available on redundancy level
    - A fully redundant protection system can be realized using separate and independent sensing devices, trip modules, protective relays, and batteries
  - No information was available on whether the adverse interaction with other schemes had been properly evaluated (and how)

Review of Existing Schemes: Checklist

- Does the scheme describe the intended purposes, conditions, and actions?
- Do the modelling and its intended actions appear to achieve the desired system performance objectives?
- Are the actions permissible in accordance with Transmission Planning Criteria?
- Do the actions satisfy Transmission Planning (or any other applicable) Criteria?
- Has the scheme been assessed within the last 5 years?
- Are the set thresholds of actions appropriate to meet system performance objectives?
- Is the logic event-based only (as opposed to partly/fully parameter-based) which does not pose high potential for interaction with other schemes in the same region?
- Is the effect of inadvertent activation or failure to operate likely to be local (as opposed to widespread, using ~ 300/1000 MW load/generation loss threshold)?
- Are the near-term system plans unlikely to have a significant effect on the scheme which would warrant its re-assessment (including its continued need, serving the intended purposes, & meeting current performance requirements)?

Review of Existing Schemes: Recommendations

- None: 9 out of total of 110 schemes (78 SPSs and 32 islands)
- Provide map/single-line diagram in the scheme (80)
- Re-assess the scheme (47)
- Review after completion (22)
- Provide all information (15)
- Complete/modify information (13)
- Coordinate with other schemes (11)
- Resolve discrepancies (7)
- Clarify information (5)
- Combine with another scheme (3 pairs)
- Use the information sheets as the minimum requirement for creation and maintenance of a database

Review of Interoperability of SPSs in the Same Area

- Interoperability is the ability of systems and devices to work together easily and effectively by design and without significant user intervention:
  - ***Technical Interoperability:*** Covers the physical and communications connections between and among devices or systems
  - ***Informational Interoperability:*** Covers the content, semantics, and format for data or instructions flows
  - ***Application Interoperability:*** Covers Supervisory Control and Data Acquisition (SCADA), Energy Management System (EMS), Business Management System (BMS), etc.
  - ***Organizational Interoperability:*** Covers the relationships between organizations and individuals and their parts of the system, including business/legal relationships
- Standardized communication protocols: IEC 61970 & 61850
  - 61970 guidelines facilitate the integration of applications developed by different suppliers in the control center environment
  - 61850 includes standards for substation automation/advanced protection

Review of Interoperability: Conclusions

- There has been little formal analysis conducted of the impacts of interoperability within the power system
- SCE is the only utility that has implemented SPS interoperability
- SCE's C-RAS is the only available example for a meaningful analogy to be made to a similar endeavor that might be undertaken for the SPS situation of the Indian power system
- Hands-on training with the utility-specific relays and testing tools are needed to speed up the development process
- Interoperability can facilitate SPS coordination to remove possible interferences/interactions
- It is prudent for decision-makers to go through a host of checklists aimed at scrutinizing investment proposals more deeply, before embarking on a major project

Identification of System Separation Locations

- Islanding schemes in India (last resort) have been based on under/over-frequency relays installed on pre-identified feeders
- To avoid cascading failures in a large power system, Out-Of-Step (OOS) relays may be installed on selected locations
  - Government of India's Taskforce (Dec. 2012) recommended the provision of OOS relays on all selected lines
  - Tripping well after the swing passes the 180° position is the recommended option to avoid excessive Transient Recovery Voltage (TRV) on breakers
- OOS relay placement is generally determined through transient stability (positive-sequence time-domain simulation) studies
  - 2 s typical unblocking time to screen for slow/unrecoverable power swings
  - Swing center detection is then based on apparent impedance calculation
    - Accurate dynamic data is crucial
- Static methods may be quicker but inherently less accurate

System Separation: Contingency Ranking

- 5-cycle 3-phase fault of every 400 & 765 kV branch & its tripping, large generation unit tripping, & single pole HVDC link blocking
  - OOS relays are assumed on all 400 & 765 kV ac lines
    - **OOS Relay Margin (%) = 100 × (Apparent Impedance / Line Impedance Magnitude – 1)**
    - Negative margin means apparent impedance < line impedance, i.e., relay sees the swing as a short circuit on the line and might signal its tripping
    - A large positive margin means the relay does not detect any significant voltage drop
  - The line with minimum relay margin is found for every contingency
  - Contingencies are ranked based on corresponding minimum relay margin
- Feb16 peak and off-peak cases (existing system) were screened
  - All relays showed significantly positive margins during all simulations
    - No listed line would necessarily be disconnected by such relays
  - Results of the top 20 single contingencies were reported
    - Indicate potential separation locations, i.e., the best candidates for OOS relay placement and power swing monitoring

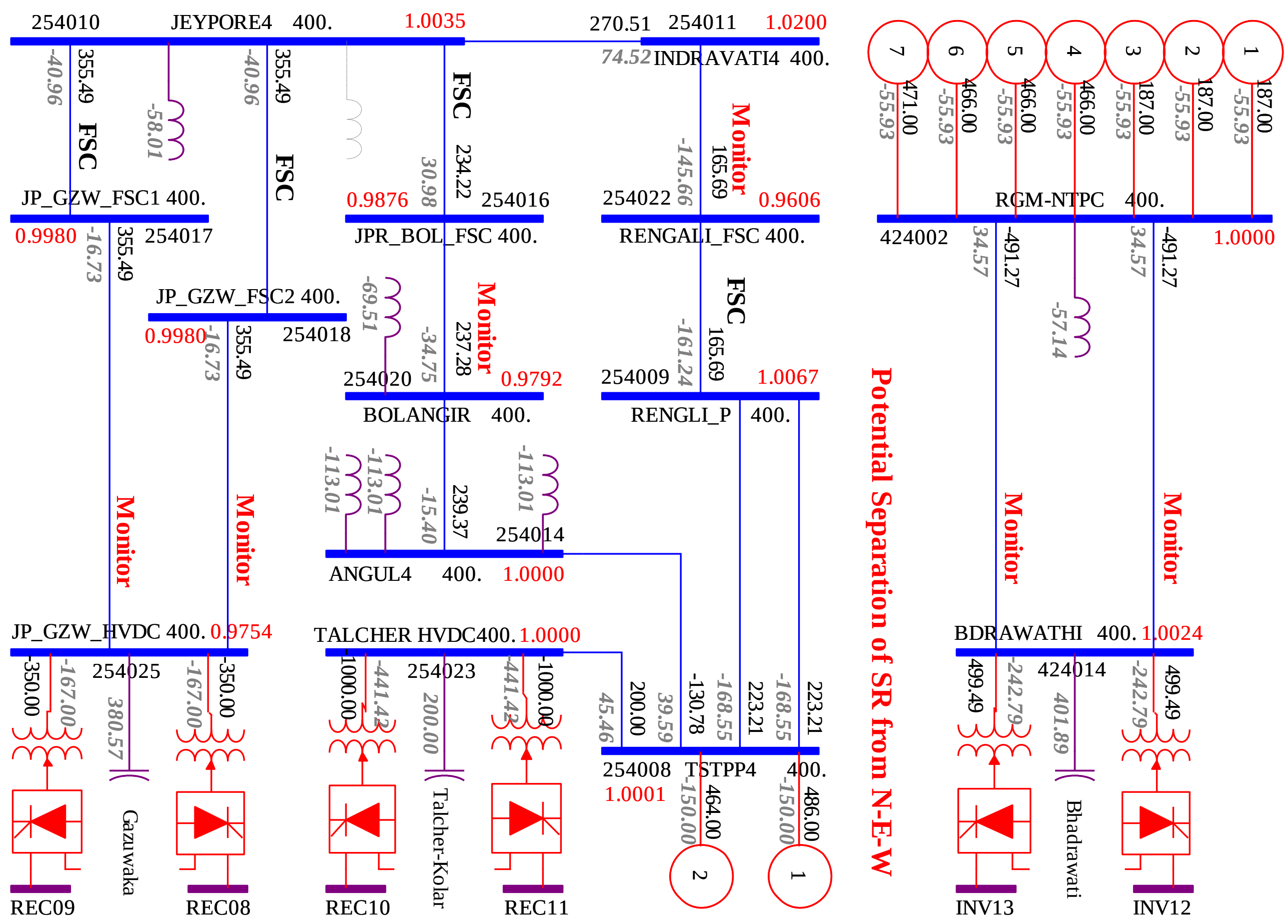
System Separation: Top 20 Contingencies

- First bus of the contingency is the faulted bus
- First bus of the line with minimum margin is OOS best location

Rank	Single Contingency in Feb16 Peak Case	Line with Minimum OOS Relay Margin	Margin (%)
1	424002 RGM-NTPC 400. 424014 BDRAWATHI 400. 1	424014 BDRAWATHI 400. 424002 RGM-NTPC 400. 2	44.8
2	424014 BDRAWATHI 400. 424002 RGM-NTPC 400. 1	424014 BDRAWATHI 400. 424002 RGM-NTPC 400. 2	46.0
3	154056 SINGRL4 400. 154014 ANPARA4 400. 1	154056 SINGRL4 400. 154008 LUCKN_UP 400. 1	53.5
4	337002 AKOLA 765. 334038 AKOLA-II 400. 1	334030 TIRORA 400. 334031 WARORA 400. 1	53.6
5	334038 AKOLA-II 400. 337002 AKOLA 765. 1	334030 TIRORA 400. 334031 WARORA 400. 1	53.7
6	154014 ANPARA4 400. 154056 SINGRL4 400. 1	154056 SINGRL4 400. 154008 LUCKN_UP 400. 1	56.7
7	157000 ANPARAC 765. 157002 UNNAO7 765. 1	154056 SINGRL4 400. 154008 LUCKN_UP 400. 1	62.2
8	334031 WARORA 400. 334030 TIRORA 400. 1	334030 TIRORA 400. 334031 WARORA 400. 2	62.7
9	157002 UNNAO7 765. 157000 ANPARAC 765. 1	154056 SINGRL4 400. 154008 LUCKN_UP 400. 1	62.8
10	334030 TIRORA 400. 334031 WARORA 400. 1	334030 TIRORA 400. 334031 WARORA 400. 2	62.9
11	334030 TIRORA 400. 337001 TIRORA 765. 1	334030 TIRORA 400. 334031 WARORA 400. 1	64.4
12	337001 TIRORA 765. 334030 TIRORA 400. 1	334030 TIRORA 400. 334031 WARORA 400. 1	64.8
13	154056 SINGRL4 400. 154049 FATEH-PG 400. 1	154056 SINGRL4 400. 154008 LUCKN_UP 400. 1	65.0
14	314035 CGPL 400. 314006 JETPUR 400. 1	314006 JETPUR 400. 314035 CGPL 400. 2	65.0
15	154014 ANPARA4 400. 154018 OBRA4 400. 1	154056 SINGRL4 400. 154008 LUCKN_UP 400. 1	65.2
16	ONE POLE OF RIHAND-DADRI HVDC LINK	154056 SINGRL4 400. 154008 LUCKN_UP 400. 1	65.5
17	154024 MEERUT 400. 167000 TEHR-POL 400. 2	154051 MEERTFS1 400. 167000 TEHR-POL 400. 1	65.6
18	254010 JEYPORE4 400. 254017 JP_GZW_FSC1 400. 1 & 254017 JP_GZW_FSC1 400. 254025 JP_GZW_HVDC 400. 1	254025 JP_GZW_HVDC 400. 254018 JP_GZW_FSC2 400. 2 & 254018 JP_GZW_FSC2 400. 254010 JEYPORE4 400. 1	65.6
19	254025 JP_GZW_HVDC 400. 254017 JP_GZW_FSC1 400. 1 & 254017 JP_GZW_FSC1 400. 254010 JEYPORE4 400. 1	254025 JP_GZW_HVDC 400. 254018 JP_GZW_FSC2 400. 2 & 254018 JP_GZW_FSC2 400. 254010 JEYPORE4 400. 1	65.6
20	154056 SINGRL4 400. 154053 ALLAHABA 400. 1	154056 SINGRL4 400. 154008 LUCKN_UP 400. 1	66.1

System Separation: Indicated Elements in ER & SR

- When either of [RGM-NTPC 400]–[BDRAWATHI 400] circuits is cleared, there is a potential for the 2nd circuit to be tripped by its OOS relay
- Four 400 kV series-compensated lines close to Gazuwaka and Talcher-Kolar HVDC links are also good candidates for monitoring



Powertech

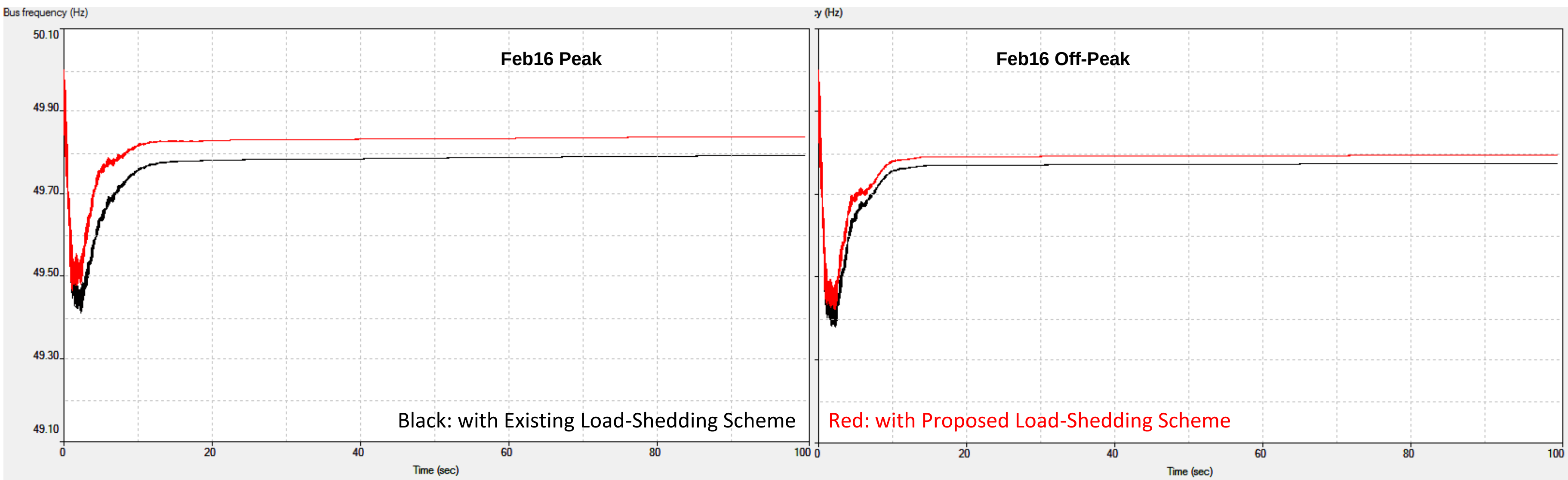
System Separation: SR Islanding of Existing System

- Existing settings of load-shedding relays are not quite suitable
  - df/dt relays act disproportionately as the rate of frequency fall varies
  - UFLS start at 49.2 Hz which is lower than likely minimum frequency
    - Only df/dt relays get activated (df/dt relays not common in North America)
  - Proposed scheme: Raise UFLS thresholds by 0.4 Hz & remove df/dt relays
    - Performs better & load shed is more consistent with the imbalance level

SR Summary	**Feb16 Peak Base Case**		**Feb16 Off-Peak Base Case**	
	MW	**%**	**MW**	**%**
Island Generation	36349	89.0	30461	87.0
Island Load before Tripping	39227	96.1	33795	96.5
Island Losses	1603	3.9	1222	3.5
Island Load and Losses	40830	100.0	35017	100.0
Island Imbalance	4480	11.0	4556	13.0
Shed Load by Existing Relays	1393	3.4	1728	4.9
Shed Load by Proposed Relays	2417	5.9	2085	6.0
Possible Load Shed by Talcher-Kolar SPS	1500	3.7	1500	4.3
SR Frequency with Existing Relays	**Hz**	**Second**	**Hz**	**Second**
Minimum Bus Frequency	49.41	2.38	49.38	2.29
Minimum Rotor Speed	49.23	1.76	49.26	2.38
Final System Frequency	49.79	100	49.77	100
SR Frequency with Proposed Relays	**Hz**	**Second**	**Hz**	**Second**
Minimum Bus Frequency	49.47	1.14	49.42	2.29
Minimum Rotor Speed	49.35	1.76	49.30	2.38
Final System Frequency	49.84	100	49.79	100

System Separation: SR Islanding of Existing System

- Governor response appears to have a major (& optimistic) effect
  - SR spinning reserve: 35.7% peak, 39.3% off-peak
    - Effective use of the reserve depends on the actual governor droops & speed deviations
- Fast handling of over-voltages, which might occur due to high charging of lines that might become lightly-loaded, is critical
  - Exciter response is important (typical data – slow)
  - Timely switching of shunt reactor/capacitor banks
    - Over-voltage relays are not modelled as voltages are managed within the typical settings



System Separation: Other Methods

- Locating system electrical center (swing center or voltage zero) & assessing its position versus the corresponding transmission line
  - This point may be located using short circuit equivalents
    - Calculate Thevenin equivalents of both sides of the line, as well as the transfer impedance between its two ends, all with the line open circuited
    - Calculate total impedance between the two sources with the line in – its mid-point is the voltage zero point when the two sources have equal amplitude but are 180° apart
  - OOS relay sees a voltage zero on (or close to) the line as a short circuit
  - Quicker for ranking and short listing (if automated) but approximate
    - Unnecessary, since we can run a very large number of contingencies in a reasonable amount of time using TSAT
    - Only a convenient way of determining the requirement of OOS blocking or tripping during the feasibility studies of new interconnections when the exact dynamic data is not available yet, as well as the cost of dynamic studies is not justified
    - New units may be required to be capable of withstanding at least one pole slip (i.e., tripping delay beyond 180°) without damage to their rotor shafts, unless breakers are rated for 180° out-of-phase voltages

Conclusions: Consolidated Recommendations

- Creation and maintenance of a database for SPSs and islanding schemes is highly recommended in the suggested format
- Complete redundancy is recommended to be considered in the design of an SPS with diagnostic and self-check features to detect and alarm when essential components fail or critical functions are not operational
- SPS coordination may be carried out to remove the possible interferences/ interactions
- Periodic review, every 5 years, is recommended for SPS & islanding documents
- Review reports may provide further discussions of SPS formats and should clearly state applicable recommendations
- Maps may be provided in SPS documents
- Accurate dynamic data is required for OOS relay simulation studies which is highly recommended before any implementation/activation of such relays
- For islanding schemes, not only the above study types, but also motor starting and transformer energization studies are recommended
- Single line diagrams may be provided in islanding documents