Report of Task Force to Review Framework of Point of Connection (PoC) Charges

March, 2019

Central Electricity Regulatory Commission
36, Janpath, Chanderlok Building
New Delhi -110001

Task Force to Review framework Point of Connection (POC) Charges

Foreward

The Commission vide office order dated 10.7.2017 formed a Task Force to "Review of the framework Point of Connection (POC) Charges under the Chairmanship of Shri A.S.Bakshi, Ex-Member, CERC. The terms of Reference (ToR) were interalia to critically examine the efficacy of the existing PoC mechanism, deficiency in the existing mechanism, if any, and in the light of issues and concerns of various stakeholders suggest modifications required in the existing mechanism.

The Task Force held eight meeting between July 2017- March 2018 and held widespread consultation with the stakeholders, MoP, international experts, power systemexperts and academia.

The Task Force has finalized its report after exhaustive literature survey, considering the issues raised by stakeholders and their suggestions and hereby submits its report on "Review framework Point of Connection (POC) Charges" to the Commission.

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Constitution of the Task Force to review of the framework Point of Connection (PoC) Charges

Members

1. Shri A. S. Bakshi, Member, CERC : Chairperson
2. Shri M.K. Anand, Chief (Finance), CERC
3. Shri S.C. Shrivastava, Chief (Engg.), CERC
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5. Shri Ravinder Gupta, Chief Engg., PSP&PA-I, CEA
6. Ms. Manju Gupta, Sr. GM ,CTU, POWERGRID
7. Shri Dilip Rozeker, Sr. GM (IB), POWERGRID
8. Ms. Shilpa Agarwal, Joint Chief (Engg.), CERC : Member Secretary

Special invitees

1. Ms. Anjuli Chandra, Member, PSERC
2. Shri M.S. Puri, Member, HERC
3. Shri S.K. Soonee, Advisor, POSOCO
4. Shri Vijay Menghani, Chief Engineer, CEA
5. Shri Pardeep Jindal, Chief Engineer, NPC, CEA
6. Prof. S.A. Soman, IIT, Mumbai
7. Prof. A.R. Abhyankar, IIT, Delhi
8. Shri V. Srinivas, Deputy Chief (Legal), CERC

Acknowledgement

The Taskforce is thankful to the Commission for constituting the taskforce and creating a platform to deliberate on a very contentious topic of PoC charges. The taskforce would like to place on record its appreciation for the inputs provided by NLDC, CTU, and CEA. The taskforce would like to say special thanks to Prof. A.R. Abhyankar, IIT Delhi and Prof. Soman, IIT Mumbai for their valuable insights. The members are thankful for the the inputs provided by Ms. Anjuli Chandra, PSERC and Shri M.S. Puri, HERC.

The taskforce is thankful to Sh. Anil Thomas, SRPC for carrying out exhaustive data analysis. The taskforce is also thankful to Shri. Rajiv Porwal, NRLDC for making the data available for analysis and his suggestions. The taskforce would also like to thank Shri Gaurav Verma, NLDC for providing the inputs on behalf of NLDC. The taskforce expresses its gratitude to Shri Puneet Chitkara, KPMG for assisting the taskforce with his feedbacks for improvement of the mechanism. Shri. Vijay Menghani, CEA provided extensive support through his critical thinking and constructive insights. Taskforce is extremely thankful to Mr. S. K. Soonee for his guidance. The taskforce would like to place on record its deep appreciation of the inputs of Prof Ignacio, MIT .The members are thankful to Shri. Pradeep Jindal, CEA for his inputs on the framework. The taskforce is thankful to all the stakeholders for providing feedbacks for improvements.

The taskforce acknowledges painstaking efforts made by the CERC officers namely Shri Agam, Shri Harish, Ms. Sonika, Shri. Sharique, Shri Gaurav. I would like to particularly thank Ms. Shilpa Agarwal, Joint Chief Engineering for extensive research and collating, compiling and drafting the report from the inputs and voluminous material available from various sources.

13/3/19

(A.S. Bakshi)
Chairperson of the taskforce

List of Acronyms

AC	Alternating Current
AGC	Automatic Generation Control
AP	Average Participation
APL	Adani Power Limited
APDCL	Assam Power Distribution Company Ltd
ARR	Annual Revenue Requirement
ATC	Available transfer Capability
ATS	Associated Transmission System
BRPL	BSES Yamuna Power Ltd
BSPCL	Bihar State Power Holding Company Ltd
BYPL	BSES Yamuna Power Ltd
CAGR	Compound Annual Growth Rate
CEA	Central Electricity Authority
CERC	Central Electricity Regulatory Commission
CKM	Circuit Kilometer
CPSU	Central Public Sector Undertaking
CTU	Central Transmission Utility
DC	Direct Current
DER	Distributed Energy Resource
DICs	Designated Interstate Customers
DISCOM	Distribution Company
DNH	Dadra and Nagar Haveli
EHV	Extra High Voltage
EPS	Electrical Power Survey
ERCOT	Electric Reliability Council of Texas
FACTS	Flexible Alternating Current Transmission System
FCFS	First Come First Serve
FERV	Foreign Exchange Rate Variation
FERC	Federal Electricity Regulatory Commission
FSC	Fixed Series Capacitor

FTR	Financial Transmission Rights
FPA	Federal Power Act
GETCO	Gujarat Energy Transmission Corporation
GNA	General Access Network
GRIDCO	Grid Corporation of Odisha
GUVNL	Gujarat Urga Vikas Nigam Ltd
HCPTC	High Capacity Power Transmission Corridors
HERC	Haryana Electricity Regulatory Commission
HVDC	High Voltage Direct Current
ICT	Inter Connecting Transformer
IEGC	Indian Electricity Grid Code
IEX	Indian Energy Exchange
IEEE	Institute of Electrical and Electronics Engineers
IPP	Independent Power Producer
ISGS	Inter-State Generating Station
ISTS	Inter-state Transmission System
KPTCL	Karnataka Power Transmission Company Ltd
LC	Letter of Credit
LCRIF	Locationally Constrained Resources Interconnection Facility
LILO	Loop In Loop Out
LODF	Line Outage Distribution Factors
LMP	Locational Marginal Pricing
LTA	Long Term Access
LTAA	Long Term Access Agreement
MCR	Maximum Continuous Rating
METI	Ministry of Economy, Trade and Industry, Japan
MoP	Ministry of Power
MP	Marginal Participation
MSEDCL	Maharashtra State Electricity Distribution Co. Ltd
MTC	Monthly Transmission Charges
MTOA	Medium Term Open Access

MVA	Mega Volt Ampere
MWhr	Mega Watt/hr
NEP	National Electricity Plan
NER	North Eastern Region
NLDC	National Load Despatch Centre
NTPC	National Thermal Power Corporation Limited
PEDs	Power Electronic Devices
PGCIL	Powergrid Corporation of India Limited
PJM	PJM Interconnection LLC
PLF	Plant Load factor
PoC	Point of Connection
POSOCO	Power System Operation Corporation
PPA	Power Purchase Agreement
PSERC	Punjab State Electricity Regulatory Commission
PSS	Power System Stabiliser
PSSE	Power System Simulator for Engineering
PSU	Public Sector undertaking
RE	Renewable Energy
RLDC	Regional Load Despatch Centre
RLNG	Regasified Liquefied Natural Gas
RoW	Right of Way
RPC	Regional Power Committee
RPO	Renewable Purchase Obligation
RTDA	Regional Transmission Deviation Account
RTO	Regional Transmission Organisation
RTM	Regulated Tariff Mechanism
SC	Shunt Capacitor
SCM	Standing Committee Meeting
SEB	State Electricity Board
ShR	Shunt Reactor
SLDC	State Load Despatch Centre

SOL	System Operating Limit
SPP	South African Power Pool
SR	Southern Region
SRPC	Southern Region Power Committee
STATCOM	Static Compensator
STOA	Short Term Open Access
STTP	Super Thermal Power Station
STU	State Transmission Utility
SVC	Static VAR Compensator
TANGEDCO	Tamil Nadu Generation & Distribution Company Ltd
TBCB	Tariff Based Competitive Bidding
TCSC	Thyristor Controlled Service Capacitor
TEPCO	Tokyo Electric Power Company
ToR	Terms of Reference
TRMID	TRM Implementation Documents
TSP	Transmission Service Provider
TTC	Total Transfer Capability
TPDDL	Tata Power Delhi Distribution Limited
TSTPS	Talchar STPS
TUOS	Transmission use of System
UCPTT	Uniform Common Pool Transmission Tariff
USAID	United State Agency for International Development
UVLS	Under Voltage Load Shedding
VC	Validation Committee
VOLL	Value of Load Loss
WRPC	Western Regional Power Committee
YTC	Yearly Transmission Charges

Table of Contents

List of Tables

List of Figures

Executive Summary

1 CERC issued CERC (Sharing of Inter-state Transmission charges and Losses) Regulations, 2010 on 15.6.2010 effective from 1.7.2011. The regulations were framed after discussions and consultation with Stakeholders starting in 2007 with an approach paper.

2 The basic intent of the Regulation was to make the sharing of inter-state transmission charges distance, direction, quantum of flow sensitive as required by Tariff Policy. Prior to the issue of these regulations, the transmission charges as agreed to be paid by beneficiaries of the region were pooled for the region and paid for by beneficiaries of the regions i.e. regional postage stamp method. Prior to 2002-03, the transmission charges were shared on the basis of energy drawl. There have not been reported disputes or discontentment vis a vis such regional charges.

3 Before the current sharing regulations came into force, a number of pools and sub-pools for sharing of charges had been created to take care of concern of entities who did not perceive any benefit from a planned transmission system.

4 Regional Postage stamp methodology for sharing of transmission charges amongst its users served satisfactorily for nearly two decades starting from early nineties. However, post Electricity Act, 2003 radical changes were introduced in electricity sector primary amongst these being introduction of competition in all facets viz. generation, transmission and distribution. Further, with the progressive integration of regional grids the foot prints of electricity selling and buying spread beyond regional boundaries. Therefore, some disadvantages of regional postage stamp method started manifesting themselves. Few of the major factors that required addressing were pancaking of transmission charges and losses for transfer of power across regional boundaries, requirements of Case-I bidding for generation, introduction merchant generators which rely in short term markets, introduction of electricity exchange etc. Further, the Tariff policy mandated the transmission charges to be sensitive to distance, direction and quantum of power flow gave major fillip to new methodology of transmission charges and losses sharing. Accordingly, Point of Connection methodology was introduced in the Indian power sector. Despite the fact that PoC mechanism was introduced after extensive consultation and following due regulatory process, after the introduction of the PoC methodology few States approached courts challenging the implementation methodology of New Sharing Regulations. The methodology which was projected to be distance, direction sensitive was not appearing the same to some States on multiple grounds. Main grouse was

introduction of 3 slabs with Rs. 15000 /MW/month as slab width which seemed to compromise the distance, direction sensitivity of the proposed mechanism.

5 The regulations were amended with major changes in 2015 vide which slabs were increased from 3 to 9 and methodology of slab width was modified to be based on statistical principles.

6 Over last 7-8 years, there has been substantial development in Power Sector, with rapid growth in both generation capacity and transmission network. Thus the country has seen transition from deficit scenario to surplus capacity as well as almost congestion free network. ISTS Transmission system has grown from YTC of about Rs. 10000 Crore in 2011 to YTC of about Rs. 36000 Crore in 2019 leading to increase in charges for almost all entities. The relative increase for a few entities is more compared to rest depending on allocation of charges determined based on utilisation of such entities.

7 Some of these States have raised issues qua the PoC mechanism. Few other states have communicated a few deficiencies with the current mechanism and have sought improvements in the prevailing PoC mechanism.

8 Keeping in view the fact that CERC (Sharing of inter-state transmission charges and losses) Regulations were issued in 2010. With time and experience, periodic review of the regulation was envisaged and keeping in view demands of stakeholders, the Commission constituted a taskforce vide CERC's Office Order dated 10.7.2017 under Chairmanship of Shri A.S. Bakshi, Member (Technical),CERC.

9 The taskforce has exhaustively discussed spectrum of issues related to PoC mechanism with all stakeholders and have covered all such comments which were received at different points of time in this report. The taskforce has attempted to suggest changes in present mechanism to address the issues raised.

10 A unique characteristic of transmission pricing which is petinent to be highlighted is that the transmission charges has to be recovered in full and it is the sharing within the set of payees which will change with any change in mechanism. Thus any decrease of charges for one payee will definitely lead to increase of charges for other payees. If reduction of payable charges is the satisfaction measure of stakeholders, it is impossible to satisfy all the stakeholders. Therefore, an attempt has been made to address the issues raised till date. Transmission cost allocation is an ever evolving process in India as well

as internationally. We have observed that transmission pricing issues have reached courts at least in two countries viz America (FERC) and New Zealand.

11 The taskforce has carried out extensive literature survey and has studied the practices across the World. Prof. Iganacio, MIT , an eminent person in this field was also consulted for his suggestions.

12 The current PoC mechanism is Ex-ante i.e the allocation of charges is decided in advance based on projected load/generation for next quarter. Over the years, States have learned that reducing load and increasing generation in projection may result in lower charges. Since it is the responsibility of payers to project their load/generation and there is almost no penalty for wrong projections (By definition, projections are forecasts after all which are uncertain), it has become more and more challenging in Validation Committee Meetings to finalise load / generation figures since each figure has its associated commercial implications. It has been observed that different figures are provided for load/generation for LGBR and for PoC.

13 After taking consideration of the experiences of last eight years, suggestions received from all stakeholders and detailed discussion in the committee, two options for transmission pricing have been proposed viz (a) modifications in the present PoC method and (b)Uniform charges method.

(a)**Modifications in present PoC method-Modified PoC method**

(i) Computation of PoC to be carried out Ex-Post on monthly basis based on actual scenario. Actual All India peak scenario for the month shall be taken for computation of PoC charges.

(ii) The MTC shall be considered under following heads
- AC system
- HVDC system
- Transmission system for Renewable with transmission charges waiver

(iii) The MTC for the entire AC system (for each line) excluding lines identified under renewables (with waiver of charges) shall be divided into three components viz.

1. POC portion: based on ratio of Base case flow in the load flow corresponding to the All India peak scenario for the month and loadability as per CTU website used for TTC/ATC.

2. Reliability Portion –based on difference between base flow corresponding to the All Peak Scenario and the maximum flow observed for the (n-1) contingency divided by loadability.
3. Residual portion - which is balance of the charge for each line after deducting POC and reliability portion.

(iv) The above three portions shall be shared amongst the DICs in the manner as described below:

1. POC portion: This portion shall be shared by each DIC corresponding to the actual utilisation of ISTS in each 15 minutes block. The same shall be arrived at by multiplication of blockwise POC rate (as derived from Webnet software) by actual MW in a given time block. The generation corresponding to untied LTA under All India peak generation shall be considerd for generators for cost allocation.

2. Reliability Portion – This portion shall be shared by each in DIC in the ratio of non-coincident Peak power drawn/injected during to the month to the sum of non-coincident Peak power drawn/injected during to the month. The generation corresponding to untied LTA under peak generation shall be considerd for generators.

3. Residual Portion – This portion shall be shared in ratio of LTA/MTOA of each DIC and the total LTA/MTOA on All India basis in the ISTS. For generators this shall be taken as untied LTA as being done currently.

(v) To arrive at the POC rate, the zonal charges determined for All India peak scenario for the month shall be divided by an entity's ISTS injection / drawal at that block. There is no need for put these rates into slabs. There may be 40-50 such rates depending upon the number of ISTS payers in the grid.

(vi) The charges shall be determined ex-post i.e based on actual scenario. Actual All India peak scenario for the month shall be taken. The actual data at ISTS points is available with POSOCO. The base case file shall be prepared so as to get the actual load/generation for ISTS points and corresponding data for intra-state network should be provided by DICs . However in absence of such actual data for intra-state points, the data for such intra-state points shall be included in simulation, so as to approximate the actual drawal/injection at ISTS interface. This is subject to necessary adjustment required for load generation balance.

(vii) It may happen that an entity was injecting / drawing less at time of All India peak. It is also observed that injection / drawal varies in every block. An entity's PoC rate shall be multiplied by its actual injection/drawal for each block. Due to billing on actual blockwise MWs, there may be over or under-recovery of MTC for PoC portion based on DICs drawal/injection during All India peak vis a vis its blockwise drawal/injection. Any over-underrecovery shall be djusted from next months' MTC.

(viii) There will be no change in the treatment of Merchant generators.

(ix) HVDC

The HVDC except back to back HVDC or the one declared as National asset shall be shared on causer pays principle as being done currently and shall not be part of uniform charge or modified PoC charge. The HVDC charges for such HVDC system shall have % reliability component which shall be equivalent to the % reliability component as derived for the entire AC system. The reliability component of HVDC charges shall be added to reliability component for AC system and shared on the basis of non-coincident peak. Back to back HVDC shall be billed under reliability component of AC system. National asset shall be shared based on LTA/MTOA as done currently.

(b) **Uniform Charges method**

The Monthly transmission charge for AC system and back to back HVDC shall be divided by sum of average ISTS drawal/injection for the month. This rate shall be multiplied by actual ISTS drawal / injection while billing. The HVDC except back to back HVDC or the one declared as National asset shall be shared on causer pays principle as being done currently. Since no reliability component is being calculated separately under Uniform charge method, no reliability component shall be considered for HVDCs except for back to back whose treatment is given above.

(c) The charges for transmission systems augmented to accommodate renewables shall be kept out of the above systems and shall be separately billed uniformly to all DICs as a public policy asset with its implications transparently available to all payers.

(d)In the proposed methodologies, distance, direction and quantum sensitivity shall be as under:

(i) Modified PoC- PoC component shall be distance, direction and quantum sensitive. Reliability and Residual component shall be quantum sensitive only.

(ii) Uniform methodology- The charges shall be quantum sensitive and not distance and direction sensitive.

14 In addition to the two options suggested above, additional option suggested by members is as follows:

(a)Ms. Manju Gupta,CTU suggested an option as "Hybrid Uniform Charges method" as follows:

The Monthly transmission charge shall be recovered in two parts – one part based on usage and the other part based on contracted capacity. The weightage of these two parts may be considered as 50: 50 or 40 (usage) : 60 (contracted capacity). Alternatively, after making calculations in option 1 i.e. modified POC Method, the percentage of transmission charges allocated based on utilization and Reliability may be recovered through uniform charges based on usage i.e. MU. The balance percentage of transmission charges (corresponding to Residual Charges) may be recovered through uniform charges based on contracted capacity.

(b)Chief (Engg.), CERC suggested an option as follows:

Sharing of transmission charges could be in two parts. First part in the nature of fixed component to be shared proportionate to the respective LTAs irrespective of usage and the second part in the nature of variable component to be shared in proportion to average usage preferably or the peak usage.

From the last five year data of actual flows through the lines, average flows in the lines may be captured as a percentage of the line capacities. As such, the variable component shall be set at this average percentage of the monthly transmission charges which may be shared in proportion of actual average drawals of the month of respective DICs. The fixed component shall be balance percentage of the monthly transmission charges which may be shared in proportion to the respective LTAs of the DICs. Value of fixed component and variable component may be reviewed from time to time.

15 Based on the comments of stakeholders and terms of reference of the taskforce, following issue-wise recommendations have been made:

(a) The efficacy of the existing PoC mechanism has been examined and has been acknowledged by the taskforce that POC has served its purpose as enshrined in Tariff Policy namely sensitive to distance, direction and quantum of flow. Further the mechanism has enabled the power market and has helped in reducing congestion by improvement in investment in the sector. Over the years from 2011-12 to year 2017-18, despite high growth in overall unconstrained volume of electricity @ CAGR of 18%, the % volume of electricity not cleared due to congestion has decreased @ 42% in power exchanges.

(b) **PoC rate variation**: On the issue of quarter on quarter PoC rate variation, taskforce has concluded that the rates are bound to vary with increasing monthly transmission charges and varying ISTS drawal of all States.

(c) **Transparency:** Stakeholders have suggested that data related to PoC calculations should be available in user friendly format. The taskforce has suggested that node wise base case load and generation data used while calculating allocation of charges or losses, New lines/systems added while billing for a particular month as compared to last month, Lines/system which have been taken out in current month billing over last month, detailed calculation of indicative cost to conclude how the average cost of each line has been derived should be available on website of NLDC in user friendly "Excel" format to enhance transparency. Further, an interactive "query" should be designed to give results like (i) Given generator is meeting which loads and in what proportion, (ii) Given load(s) is met by which generators and in what proportion, (iii) Given DIC is using which transmission lines and in what proportion, (iv) Given Transmission is serving which DICs and and in what proportion etc.

(d) **Actual line wise MTC vs. MTC calculated on average cost method :**Electricity flows through laws of physics and not through contract path or desired path. Hence it is not the drawing entity or injecting entity which decides which line ie. Old line or new line is to be used for its drawal. Hence there should not be difference in tariffs considered for such lines. Further, the new and old lines provided same service. It is recommended to continue the averaging of cost across voltage class so that distance, direction and quantum of flow sensitivity is maintained for modified PoC method. In case of Uniform charges method, the issue of averaging doesnot arise since the entire system except HVDC is averaged out.

(e) **Difference between Long term Access and Peak ISTS Drawl :** Stakeholders has suggested that for States where there is gap between LTA and peak ISTS drawal, LTA should be enhanced upto peak ISTS drawal. The taskforce has proposed a methodology which is sensitive to actual usage, Peak usage and the LTA/MTOA availed. Since the usage component is not based on LTA/MTOA, the issue gets addressed.

(f) **Slabbing**: It is suggested that PoC rate should be calculated by dividing the charges allocated to a particular entity by its ISTS drawal/ injection considered in base case. There is no need to put them under slabs since slabs are difficult to justify to entities whose charges increase due to slabbing. This PoC rate should be multiplied by actual ISTS drawal /injection blockwise to calculate the charges for a particular entity.

(g) **PoC charges on a State due to its embedded Customers/consumers :**It is observed that there are intra-state entities who may have a contract outside State, however while peak demand /ISTS drawal of a State is calculated, effect of all consumers (including captive consumers) within the State is also taken up. It may happen that such embedded consumers may not have LTA to ISTS, the charges attributable to such loads are levied on the State discom.

Since ISTS charges are fully recovered under first bill i.e from LTA and MTOA customers, for a State, no charges may be levied under STOA from embedded customers. The State should determine as to the charges to be levied on such embedded customers due to their demand from ISTS. Ideally the charges attributable to such embedded customers should correspond to ISTS drawal due to such embedded customers. The State may implement mechanism similar to that available for ISTS i.e PoC based mechanism or Uniform charges based mechanism for intra-state entities. Till such mechanism is put in place, the STOA charges collected from intra-state entities should be reimbursed back to the State.

(h) Deviation charges for injecting utility should be borne by injecting utility itself and drawing utility should not be levied charges for deviations of injecting utility.

(i) **DC loads flow vs AC load flow:** DC load flow study is an approximation of AC load flow study which ignores reactive power component. No desired results are seen for shifting from AC load flow study to DC load flow study and hence DC load flow study is not recommended under modified PoC mechanism.

(j) **Min-max method:** The method is did not find favour with the taskforce since the proposed min-max methodology is based on cross subsidisation between DICs which cross subsidises high ISTS users at the cost of low ISTS users.

(k) **Issue of Loop Flow with Average Participation:** Loop flow can't take place in pure AC system since power flows from high voltage angle to low voltage angle. Loop flows takes place primarily under wrong data entry in base case or using HVDC to pump power back. Hence there is a need to check the data entry in base case to avoid loop flows. In case loop flow is occurring due to pump back power from HVDC, such HVDC may be considered on no load such that there is no intentional pumping back of power. If required, HVDC may be kept on no load condition for system security. Such pumping back power unnecessarily takes away Available transfer capability.

(l) **Methodology for calculation of transmission losses**: WebNet software allocates losses for each node based on its usage of all India network. Whereas losses are computed at regional level and only for ISTS element. A National loss be computed for ISTS element rather than at regional level. As of now the methodology followed is (All generation at regional level- All demand at regional level)/ (All generation at regional level). It is desirable that the same may be substitute with (All generation at national level- All demand at national level)/ (All generation at national level).

However this may lead to some complexities. As such it is suggested that matter may be deliberated further with all stakeholders.

(m) **Separate rates for STOA /MTOA as compared to Long term charges :**The Taskforce agrees that STOA rates should be higher than LTA rates as proposed by Commission during draft 5th amendment to Connectivity Regulations. However keeping in view proposal of GNA mooted by Commission, in case all entities have GNA, STOA rates may be zero for such entities for transactions upto GNA quantum.

(n) **Reactive power considered in PoC software:** An issue was raised with respect to non-availability of nodewise projected reactive power data by State. The reactive power data for intra-state points is to be provided by DICs and is being currently provided by a few DICs. Hence DICs should provide proper data for the base case. Under Uniform charges method, any load flow is not simulated and hence data for reactive power is not required.

(o) **Transmission Planning**: Stakeholders have stated that every transmission scheme seeking regulatory approval should contain the details regarding its effect on the transmission capacity of the existing network along with the cost benefit analysis, incremental effect on the tariff and details regarding the beneficiaries accountable to pay the transmission charges of the same. It has also been suggested that concerned state utilities/DISCOMS should also be involved in ISTS planning. All the suggestions have duly been incorporated in Central Electricity Regulatory Commission (Planning, Coordination and Development of Economic and Efficient Inter-State Transmission System by Central Transmission Utility and other related matters) Regulations, 2018 effective from 24.8.2018.

(p) **NER to be considered as a block :** In case of treatment of region as a block few States will cross subsidize other States in the region. Any special treatment for a particular region is a policy matter and may be taken up at appropriate forum.

(q) **Locational based marginal pricing method:** Locational based marginal pricing is a methodology to recover energy cost+ congestion cost. The issue under consideration is allocation of embedded cost of transmission. Hence LMP not discussed here.

(r) **Treatment of counter flows:** the taskforce suggests that counter flows should not be charged and their marginal participation should be taken as zero under modified PoC mechanism. Under Uniform charges the issue of counter flow does not arise.

(s) **Treatment of Grid Sub-stations:** All transformers which are used for drawal of power should be allocated to DICs of the State (drawal DICs). The transformers which are used for stepping up voltage and are primarily used for injection into the ISTS grid need to be billed to its user and hence has to be modelled separately in PoC under modified PoC method. Under Uniform charges methodology, drawal transformers need to be billed to downstream entities and injecting transformers under Uniform charges.

(t) **IEX proposal on charging PoC rates for all intra-state entities in a consolidated manner:** The Taskforce observes that under the current regime, netting of transactions should not be done. Further it is proposed under GNA that all the charges be levied on a State as one entity and transactions for intra-state entities are to be levied charges by the State itself. Hence the issue will not survive as the same shall have to be decided by the State.

(u) **Ex-ante vs ex-post:** If the transmission charges have to be shared based on utilisation, then utilisation is best captured on post –fact basis i.e based on actual scenario rather than projected one. This will be fair to all entities since present system works in advantage of entities managing to project less intentionally or due to forecasting errors.

(v) **Who should pay-generator or loads:** The taskforce observes that a majority of generators have contracts for ex-bus sale of power. The responsibility to pay transmission charges in these cases is with buyers/load. Hence there is no benefit in calculating the charges separately for these generators for billing to beneficiaries in some ratio which may create distortions as acknowledged in 3rd amendment SOR. The current methodology of determination of transmission charges on the loads in case buyer is identified and on generator for cases where buyer is not identified should continue.

(w) **Status of availability of data and data telemetry in order to facilitate shifting towards actual scenario:** There may be issues in online availability of real time data due to communication issues in Powergrid/ POSOCO system / system down . We observe that realtime data may not be required for transmission charges allocation which requires data post fact. The data may be provided by DICs to NLDC/ RPC. The ISTS drawal /injection data is already being compiled by RLDCs and provided to RPCs in about a weeks time after end of the month. POC charges can be calculated for the month by end of the 2nd month for 1st month and can be billed in beginning of 3rd month.

(x) **To assess the utilization of transmission system and suggest measures to improve the utilization of transmission system:** Taskforce suggests that utilisation of transmission system should be monitored at RPC level and reasons for cases of low utilisation should be ascertained and documented. The remedial measures to improve utilisation should also be discussed. RPCs should monitor the same quarterly and upload the status report on its website. The RPC shall consider that planning of new system is done after considering redundancy in existing system as brought out in above analysis keeping in view the reliability requirements.

(y) **To assess the reactive power requirement in integrated grid and examine the adequacy of available reactive power management resources:** The taskforce observes many lines are opened on high voltage on daily basis. There is a need to conduct studies to assess reactive power requirement considering peak and off peak scenarios since the reactive power sources currently in the grid are not adequate looking at requirement of opening of lines. The same should duly take into account the future load growth and addition of renewables. The usage of solar inverter for providing reactive compensation should also be studied. The possibility of studies being done through agencies which are already involved in such studies like METI (TEPCO, Powergrid), USAID or GIZ or inhouse may be explored.

(z) **Assess the available transfer capability and the measures to improve the same:** It is observed that MoP had directed POSOCO and CTU to engage a Consultant to provide recommendations for Available Transfer Capability assessment and calculations. Consultant has provided major recommendations as (a) use of variable cost of generation i.e merit order while deciding which generation to increase or decrease.(b) Use of generation increase on sending side and generation decrease on receiving side should be done in place of load increase done by POSOCO currently since increasing load beyond peak demand is fictitious (c)Use of accurate models (d) Check voltage collapse limits to ensure system doesnot operate near voltage collapse limits**.**

It is suggested that recommendations of Consultant should be executed in time bound manner. Further POSOCO and CTU may use PV analysis or any other suitable method which includes reactive power while calculating TTC/ATC.

Chapter 1

Background

1. Introduction:

1.1. A well developed and efficiently priced transmission system is crucial for development of the power sector. The transmission system must be developed in time for new generation capacity to come on stream as well as for demand to connect to the system in a timely manner. The transmission system is also the backbone for development of efficient competitive power markets. The rapidly developing transmission system at the inter-state level has been a key factor in the evolution of power trading in the country since the Electricity Act, 2003 came into effect. More recently, operations of power exchanges have also been greatly facilitated by the increasing depth of the transmission network.

1.2. The development of transmission system in India was integrated with generation planning till 2003 and later it was governed by both integrated planning and providing long term access. The sharing of transmission charges was based on allocation of power from central sector generating stations. Inter-state transmission was originally developed at the regional level with the objective of generation evacuation from Inter-State Generating Stations. The Associated Transmission System (ATS) thus developed primarily catered to the needs of these stations and their beneficiaries who were located in the same electrical region. Transmission charges were correspondingly determined at the regional level. With the advent of generation addition and growth in demand, there has been an increase in periodic power surplus and deficit in a region. Other mechanisms for pricing of regional interconnections have been evolved by the CERC keeping in view the legal framework under Electricity Act.

1.3. The need for aligning to the future requirements of a national transmission network has become apparent over a period of time. There are many benefits of a national power system in terms of efficient development and utilisation of the resources in the system, robustness of the grid and deepening of the competitive power markets.

1.4. Keeping in view the fact that CERC (Sharing of inter-state transmission charges and losses) Regulations were issued in 2010 and required a reviewand thedemands of stakeholders, the Commission constituted a taskforce vide CERC's Office Order dated 10.7.2017 with following constitution to review POC methodology:

(a) Shri A. S. Bakshi, Member, CERC

(b) Shri M.K. Anand, Chief (Finance), CERC

(c) Shri S.C. Shrivastava, Chief (Engg.), CERC

(d) Shri S.S Barpanda, AGM, NLDC

(e) Shri Ravinder Gupta, Chief Engg., CEA

(f) Shri Dilip Rozeker, AGM (CTU-Plg.), POWERGRID

(g) Ms. Manju Gupta, AGM (CTU-Plg.), POWERGRID

(h) Ms. Shilpa Agarwal, Joint Chief (Engg.), CERC

1.5. The Taskforce co-opted following special invitees as a part of Taskforce:

(a) Ms. Anjuli Chandra, Member, PSERC

(b) Shri M.S. Puri, Member, HERC

(c) Shri S.K. Soonee, Advisor, POSOCO

(d) Shri Pradeep Jindal, Chief Engineer, CEA

(e) Prof. S.A. Soman, IIT, Mumbai

(f) Prof. A.R. Abhyankar, IIT, Delhi

(g) Shri V. Srinivas, Deputy Chief (Legal), CERC

(h) Shri. Vijay Menghani, Chief Engineer,CEA

1.6. The Terms of Reference (ToR) of the Taskforce were as follows:

(a) To critically examine the efficacy of the existing PoC mechanism to see whether the mechanism has served its purpose as enshrined in Tariff Policy namely sensitive to distance, direction and quantum of flow;

(b) The role of the existing mechanism in improving the power market;

(c) Deficiency in the existing mechanism if any, and in the light of issues and concerns of various stakeholders.

(d) To assess the status of availability of data and data telemetry in order to facilitate shifting towards actual scenario than the estimated scenario as done currently;

(e) Suggest modifications required in the Existing mechanism in due consideration of future market scenario, large scale capacity addition of renewable, introduction of GNA concept for transmission planning, introduction of ancillary services and reserves, supported by international experience in this regards;

(f) Specify reliability benefit in a large connected grid and provide methodology for determination of quantum of Reliability Support Charges and its Sharing by constituents and to provide Methodology of Sharing of HVDC Charges by constituents;

(g) Final Recommendations on Transmission pricing;

(h) In addition the Taskforce shall also study the following and make recommendations to the Commission:

   (i) To assess the utilization of transmission system and suggest measures to improve the utilization of transmission system;

   (ii) To assess the reactive power requirement in integrated grid and examine the adequacy of available reactive power management resources;

   (iii) To assess the available transfer capability and the measures to improve the same;

   (iv) Any other relevant issue

One copy of the aforesaid CERC Office Order dated 10.7.2017 is at **Annexure-I**.

1.7. The Taskforce conducted eight meetings during the period July 2017 to March 2019. The report was adopted by the Taskforce during last meeting held on 7th March 2019. A brief of proceedings of the meetings is discussed in subsequent paragraphs.

First meeting of the Task Force

1.8. First meeting of the Task Force was held on 26.7.2017. Gist of discussions held in the meeting is as under:

1.8.1. Jt. Chief (Engg.), CERC made a presentation explaining the Terms of Reference (ToR) of the Task Force. She also emphasised on the salient changes made under 3rd amendment of the Sharing Regulations and the issues raised by the States on the current methodology. She stated that among the issues raised by States, CERC has already requested NLDC to determine list of lines which are marginally used, sample study on true-up on the basis of actual demand/generation, to arrive at a methodology to consider grid substations separately in base case. She indicated that out of the issues raised by States, actions have already been initiated by NLDC on a few aspects and NLDC is working on other aspects which shall be discussed during course of meetings of the task force. She explained that the ToR of earlier formed Committee to determine Sharing of HVDC charges and quantum of Reliability Charges shall be considered under this Task Force only and apprised the members of the Task Force about the proceedings as happened in the Committee on HVDC and Reliability Charges.

1.8.2. Dy. Chief (Engg.), CERC made a presentation on the background of other aspects such as Utilization of Transmission System, Reactive Power Requirement and Methodology for Available Transfer Capability (ATC). He stated that in the context of ATC, certain tasks were assigned to POSOCO in

Congestion Sub-Committee report and that National Reliability Council have also been formed.

1.8.3. Representative of CTU submitted that the objective of the Tariff Policy to specify the distance, direction basis transmission charges is to provide location signal to the generating companies. He stated that distance, direction sensitivity is effected by making slabs. He also stated that making zones after determination of nodal charges may also curb sensitivity of nodal charges. For example charges for eastern UP and Western UP are pooled together in one zone. He raised issue of non consideration of cost for STU lines which run parallel to ISTS lines and affect the usage of system.

1.8.4. In order to solicit the views of the stakeholders, the members of the task force suggested that the comments and suggestions of the stakeholders may be invited. In addition, stakeholders may be invited in the next meeting to present their views on the issues being faced by them presently in regard to PoC mechanism.

1.8.5. After discussions, members of the task force opined that huge data collection; analysis and system study is involved in accomplishing tasks as per ToR of the taskforce. Further, following actions were decided:-

(a) NLDC and CTU will carry out following studies:

(i) The comparative analysis of PoC transmission charges on Average vs Peak PoC result,

(ii) Comparison of Nodal vs Zonal PoC result,

(iii) Comparison of results with and without slabs

(iv) Comparison of results with Postage stamp vs PoC charges method

(v) Identification of lines which are marginally used and its proposed sharing methodology

(vi) Study impact of proposed GNA on POC charges,

(b) It was decided co opt following officers as special invitees to be a part of the Taskforce.

(i) Sh. S. K. Soonee, Advisor, POSOCO

(ii) Sh. Pradeep Jindal, Chief Engineer, CEA

(iii) Prof. Soman, IIT Mumbai

(iv) Prof. Abhyankar, IIT Delhi

(v) Sh. Srinivas, Dy. Chief (Legal), CERC

Second meeting of the Task Force

1.9. Second meeting of the Task Force was held on 8.8.2017. Gist of discussions held in the meeting is as under:

1.9.1. Sh. Pradeep Jindal of CEA gave a detailed presentation on Report of the consultant M/s Powertech Labs. He stated that Ministry of Power, Govt. of India constituted a "*Taskforce on Power System Analysis under Contingencies*" as follow-up of recommendations of the Enquiry Committee on Grid Disturbances of 2012 in Indian Grid. In line with recommendations of Task Force, Ministry of Power directed PGCIL to appoint consultants to conduct study/analysis to ensure secure & reliable operation of National Grid. The Consultant M/s Powertech Labs was given Six Tasks under "Review of Transmission System Transfer Capability and Review of Operational & Long

Term Planning". He further stated that the consultant M/s Powertech Labs has submitted a report on Task –I and Task- II on 13th Jan 2017 and 7th April 2017.

1.9.2. Sh. Pradeep Jindal stated ATC calculated under planning horizon by CTU and operational horizon by POSOCO is different. He informed the Taskforce that under current methodology of ATC calculation, CTU calculates ATCby increasing generation (at source) and decreasing generation (at sink) and POSOCO calculates ATCby increasing generation (at source) and increasing demand(at sink). Consultant has suggested that increasing generation (at source) and decreasing generation (at sink) is a better method provided Generation reduction is done on merit order basis. The database files being used for ATC calculations in planning horizon and operation horizon are different. The Taskforce felt that there is a need to harmonise both the files in respect of formats.

1.9.3. Sh. S.K. Soonee emphasised the importance of validation of data used for calculation of ATC/TTC. He stated that the models should be prepared in such a way that results are close to actual.

1.9.4. Sh. Dilip Rozekar stated that in New Zealand, generator has to provide accredited data every 5 years. He also stated that in our Country, the generator doesnot provide requisite data of machine details required for modelling. He also emphasised the need of having tested data rather than generic data for generators.

1.9.5. Dr. Puneet Chitkara gave a detailed presentation on POC intent and methodology. He further pointed out following distortions in POC computation under the current mechanism of POC calculations:

(a) Merchant Generator cost is added proportionately to all entities based on their base cost share.

(b) 90% cost recovered through POC mechanism is not in line with the NEP and NTP and introduces undue benefit and loss for the entities.

(c) Slab introduces a distortion as high as 19% and as a gradual step ahead, may be done away with.

(d) Omission of Intra-state lines aiding ISTS power: RPC's certify only for one year and the procedure of getting RPC certification and petition filing to CERC for Tariff determination introduces considerable delay.

(e) HVDC charges are socialized to all entities irrespective of utilization.

(f) The methodology of moderation and Maximum injection interpretation is different in different regions and needs standardization

(g) Generators without PPAs need to be charged based on their connectivity

(h) Percentage of Total Transmission Charges to be recovered through PoC mechanism and those as Reliability charges could be determined more scientifically.

Third meeting of the Task Force

1.10. Third meeting of the Task Force was held on 11.9.2017. Gist of discussions held in the meeting is as under:

1.10.1. The representative of NLDC showed comparative analysis of PoC transmission charges on Nodal PoC result vs Zonal PoC result, comparison of results with and without slabs, comparison of results with uniform charging vs PoC charges method and list of transmission lines which are marginally used. He further stated that there is a requirement of separate rates for Injection GNA and Withdrawal GNA under the PoC mechanism.

1.10.2. The representative of CTU showed a comparative analysis of LTA/MTOA, Monthly Transmission Charges (MTC) and STOA average charges. He stated that during a period of 28 months (Jan, 2015 to May, 2017), LTA quantum has increased by about 33% and MTC has increased by about 61%, thereby the average per LTA/MTOA MW transmission charges has increased from approx. Rs. 2.35 lakhs to Rs. 2.85 Lakhs/MW. It is seen that additional 18000 MW LTA would had rendered the average per MW charges same. Further, it has been seen that during the same period the STOA charges have increased by Rs. 139 Crs i.e. about 21%. This amount corresponds to 6000 MW LTA at median slab and reliability charges as per May, 2017. If it is assumed that STOAs are used for 1/3rd time only, then this charge corresponds to 18,000 MW LTA only. Therefore, the relinquishment of LTA are largely contributing to increased LTA and MTOA charges.

1.10.3. Prof. S.A Soman made a presentation on "How to make existing CERC transmission system cost allocation mechanism cost causal?" He said that Cost causality means that entity responsible for the cost pays i.e., beneficiary pays. The most common practice is that a flow carrying entity on a transmission line is treated as its beneficiary. Prof. S.A Soman highlighted the following:

(a) Cost Causality: In the present scenario, cost of a transmission line is borne by only those entities which have a flow component on that transmission line. This compromises cost causality as the cost of unused capacity is also burdened on those few users. Using the St. Clair curve for capacity calculation of transmission line, it was shown that median (and average) loading of 765 kV lines on ISTS network for Q4 scenario of 2016-17 is respectively 8.74% and 13.51%. For the 400 kV network, it is 12.5% and 17% respectively. Therefore, it was argued that a selected few users of transmission line have to bear the cost of unused capacity. This compromises cost causality and is unfair.

It was opined that line cost rate should be computed on a line capacity base. This would also make line cost rate static i.e., independent of power flow scenario. This can be contrasted with the present approach of calculating line cost rate wherein the line cost is to be divided by the power flow on the line, which will vary from scenario to scenario. The rationale behind the present practice is to ensure complete cost recovery of the transmission system. However, if capacity based line cost rate is used, then it will only recover a fraction of the total costs. It was suggested that the unused capacity costs be socialized across all the users by a uniform postage stamp rate.

(b) Modelling of Reliability Costs: Prof. Soman further pointed that the "unused capacity" also has an intangible reliability component. He suggested a method to estimate and price the reliability costs. A procedure based upon N-1 contingency studies can be used to find maximum possible loading on the transmission line during contingencies. The excess flow multiplied with line cost rate on capacity base represents the allocation in the line cost for reliability. These costs can be shared by users in proportion to their extent of use of the network. Then, the residual costs only need to be socialized. This measure will also improve cost causality. He suggested that if the utilization of line is 15%, then 15% of its cost should be recovered on usage basis and 85% on postage stamp basis. In this 15%, an approach can be add another 15% as reliability component so that 30% cost is levied on usage basis and balance 70% on postage stamp basis.

(c) Min-max Fair Dispersed Slack Bus Selection: Prof. S. A. Soman recommended use of min-max fairness policy instead of Average Participation (AP) rule to compute dispersed or economic slack bus in the Marginal Participation (MP) approach. Min-max fair Point of Connection tariff (PoC tariff) solution is defined as one, in which, a reduction in PoC tariff of an entity (load or generator) can occur only at the expense of another entity, which pays equal or higher PoC tariff. Thus, the min-max fair price vector represents the equilibrium prices; any deviation from it increases regret of equal or higher price bearers.

Also, it is unique. It was argued that such a rigorous fair selection of economic slack bus will lead to

(i) reduction in both maximum and high PoC tariffs;

(ii) equitable price clusters.

(d) Moreover, Implementing Agency is facing a challenge due to presence of loop flows. The AP method breaks down in presence of loop flows. Loop flows occur due to the presence of HVDC lines. To circumvent loop flows, the base case has to be modified byeither altering P-Order of HVDC lines or opening of some light loaded lines.If the commission adopts min-max fair economic slack bus selection rule, then such problems in economic slack bus selection due to presence of loops flows will be automatically resolved. Power flow scenario need not be altered. Further, the procedure of slabbing after computation of PoC tariffs can be dispensed with.

(e) **Management of Counter Flows**: The next suggestion made was that benefits of counter flows should be passed on to the entities responsible for it but with line cost rate on a capacity base. With the present way of choosing line cost rate (on line flow base), for the lightly loaded lines, the benefits of counter flows, if passed through completely, become abnormally high. However, counter flows need to be encouraged, primarily, in heavily loaded lines to promote decongestion in long run.This will reduce loading on lines, losses will reduce and emissions will also reduce. If counter flows are valued on the line cost rate, then automatically its benefits will be proportionate to the loading level of the transmission line. Hence, there cannot be any excess payment. As such, the current exception clause to exempt entities who create counter flows from bearing cost of the line can be dispensed with. This will simplify the procedure.

(f) **AC vs. DC Power Flow:** Prof. Soman suggested that the implementation of cost causal MP should use either DC power flow or linearized AC power flow. This is because, using AC power flow sensitivities at an operating point only is erroneous; superposition of weighted marginal flows will not generate the correct line flow.If AC power flow sensitivity is to be used, some form of averaging from zero to the full loading condition is required. Such difficulties do not arise with DC power flow or linearized AC power flow (LAC). Further, LAC can model voltage deviations from nominal value as well as reactive power.

(g) Prof. Soman presented a case study on the scenario of Q4 (Truncated) for year 2016-17 by incorporating the above changes. The following benefits were stated by the Prof.Soman:

(i) Min-max fair MP method with cost causality implementation is fairer than the other two methods.

(ii) Slabbing is intrinsic in the MP min-max fair method.

(iii) Many entities are close to postage stamp rate.

(iv) Maximum PoC tariff is least amongst the other methods.

(v) Standard deviation of all PoC tariffs is also less which means the variationbetween entities is less.

1.10.4. Mr. S.K. Soonee suggested that STOA charges collected should be used to reduce the YTC of subsequent quarter rather than reimbursing back in next month. He also suggested that there should be benchmarking of transmission losses to make a baseline of interstate losses. Losses in the system may reduce with addition of a line. Mr. Soonee also suggested that POC should be replicated in States also.

Fourth meeting of the Task Force

1.11. Fourth meeting of the Task Force was held on 20.9.2017. The fourth meeting of the Task Force was attended by representatives of State DISCOMs, RPCs and State Regulators. The representatives of DISCOMs, RPCs and State Regulators reiterated their comments as submitted by them in writing. Other important points highlighted by participants are as under:

1.11.1. Sh. S.K. Soonee stated that there is a need to conduct more workshops and dissemination of knowledge. Further it is important to determine how much value the reliability carries. He also explained the rationale behind the slabbing. He stated that slabbing is very important to all the DICs. He further stated that all the data pertaining to POC are available on POSOCO website.

1.11.2. Chairperson of the Taskforce stated that STU's are part of the standing committee for transmission system planning whereas liability of payment of the transmission charges fall on Distribution Company who are not involved in transmission planning. He stated that in case STU's feel that transmission system discussed in standing committee meeting is not required, they should not approve such system. He further stated that States should suggest how the system can be made more transparent. He further stated that any State can approach NLDC who shall arrange the training for DICs seeking for training on PoC. Some DICs have expressed their apprehension regarding the POC mechanism. If DICs has any apprehension in POC mechanism under the Sharing of Regulation, firstly they should approach NLDC for clarification. In case they are not satisfied then they should approach to Commission through appropriate application.

1.11.3. Sh. Dilip Rozekar stated that States can ask for any details as desired by them from the concerned entities. Representative of Rajasthan stated that in Standing Committee Meetings DISCOMS are not represented and commercial parts are not discussed.

1.11.4. MS (NRPC) stated that they have conducted a workshop on POC at WRPC forum and will conduct same at NRPC also.

1.11.5. Keeping in view requests of states, it was decided that POC software may be purchased at RPC level for States. Further the analysis of impact of waiver of ISTS for renewable shall be studied separately.

Fifth meeting of the Task Force

1.12. Fifth meeting of the Task Force was held on 20.2.2018. Some of the important points were discussed and finalized during the fifth meeting are:

1.13. Shri Vijay Menghani gave a presentation explaining the variation of actual ISTS drawl and projected ISTS drawl of status of Rajasthan and Bihar State. He suggested following points under the PoC mechanism:

(a) Load and generation data used for ISTS charges and losses computation under PoC mechanism should be communicated properly by DICs.

(b) Two scenarios i.e., Average case and Peak case should be used for POC computation.

(c) HVDC charges should also be levied to Short Term Open Access (STOA) customers.

(d) DC load flow should be used instead of AC Load flow.

1.14. Prof. S.A Soman of IIT, Bombay stated that AC power flow uses non-linear ones. It makes principle of superposition valid in DC power flow and superposition of weighted marginal flows will equal line flow. Ac power flow equations are linearized only around a set operating point. He also stated that the proposed Min- Max method allocates cost of the line based on three criteria viz., usage, reliability and residual. He suggested rationale selection of economic slack bus as opposed to apriori selection of slack bus. He further stated that presently Average Participation (AP) method is used for selection of slack bus which is used in Marginal Participation (MP) to allocate costs. The costs so allocated are then slabbed. He opined that this method does not meet the fairness criteria due to its manner of selection of slack bus. Rather AP-MP Method chooses the economic slack bus of all the buses in the system and is therefore fair and unbiased. He stated that cost causality is important issue in the present AP-MP and is addresses by separating and extent of use and unused.

1.15. Prof A.R Abhyankar of IIT, Delhi suggested that the certain quantum of MTC should be socialized, slack bus be replaced with proportionate slack bus, DC load flow should be used instead of AC load flow and node wise distribution of MW in a base case should be fair. He stated that after 3rd Amendment POC charges are determined from Average to Peak snapshot. He suggested two snapshots for lean and peak period and also opined that CERC needs to benchmark the results. He was of the view that present exercise is of allocation of costs. He suggested Locational Marginal Pricing (LMP) method gives better locational signal in transmission pricing.

1.16. Shri Ghanshyam Prasad stated that Ministry of Power (MoP) is willing to amend the Tariff Policy for bringing in simplicity in determination of ISTS charges & losses. He proposed that suggestion may be given to MoP in this regard for change in Tariff Policy. He also expressed that a mechanism arrived for upfront determination of transmission charges and losses will help the DICs.

1.17. POWERGRID stated that the transmission lines created in W3 area were congested 2-3 years earlier but these lines are now underutilized. Further, the issues like termination of PPA, non- availability of coal, etc., have affected utilization of transmission system. He stated that monthly PoC charges of DICS vary due to reasons like changes in drawl patterns, seasonal variations loading to large change in load. For example, power drawl by the State of Punjab varies from 6000 MW to 12000 MW and by Delhi varies from 3500 MW to 6000 MW across the seasons, and not withstanding this, the transmission system is created for peak drawl. He suggested that a transformer should be treated as a branch in POC mechanism and PoC charges should be recovered in two parts such as 50% for the access granted to DICs and rest 50% based on the utilisation of transmission system.

1.18. Shri S.K. Soonee, POSOCO raised the following points under the PoC mechanism:

(a) It is a governance issue and cannot be solved by modelling.

(b) The gap between minimum and maximum slab should be reduced.

(c) Methodology for calculation of transmission charges & losses should be simplest and easy to understand.

(d) PoC rate should reflect good location signal.

(e) Transmission charges should be in line with the Tariff Policy i.e.,it should be sensitive to distance, direction and quantum of power flow.

(f) Injection PoC charges should not be billed on drawl entities.

(g) Short Term Open Access charges (STOA) should also reflect in RTA Bill-1.

(h) Transmission charge constitutes only 10% of the overall power procurement cost. Other components should also be economized.

1.19. The following points were discussed for conclusions:

(a) Can charges for ensuing year be notified year ahead ---would it require data of ISTS drawal of States and projected YTC of next year ?.

(b) Treatment of Marginally utilised lines (say less than 10% usage)

(c) Increase in number of slabs or doing away with slabs may be discussed.

(d) Grid Substations may be treated as separate elements in POC calculations or to be billed to downstream states.

(e) Marginal participation factor less than 0.001 can be taken as zero.

(f) Views on DC load flow vs AC load flow vs linearized AC load flow

(g) Other stakeholders comments

The conclusions were as under:

i) (a) and (b) above were agreed.

ii) It was decided that (c) needs further deliberations.

iii) For (d) it was decided that ICTs should be treated as a separate element (branch) in POC based on indicative cost to be provided by CTU.

iv) On (e) Professor Soman stated that in case cost causal methodology as suggested by him is considered there may not be need of this suggestion. It was decided that we may further deliberate on this.

v) It was also deliberated that following may also be considered:

   i. Two cases may be considered-peak/off peak with 20hr off peak and 4 hours peak.

   ii. Billing on actual drawal.

b. Need of Webnet software audit as stated by State representatives.

Sixth meeting of the Task Force

1.20. Sixth meeting of the Task Force was held on 14.5.2018. Gist of discussions is as below:

1.21. Shri Akhilesh Avasthi from IEX made a presentation on collective and bilateral transactions in exchanges. He described that there is a difference in POC pricing of intra-state bilateral vis-a-vis collective transactions. At present, intra state transactions bilateral are at a price advantage compared to collective transactions. He illustrated the price comparisonin these transactions for Rajasthan. The landed cost of intra-state bilateral traded power is Rs. 4/u while it is Rs. 4.63/u for collective traded power, in State of Rajasthan. The difference of Rs. 0.63/u in them is due to injection POC rate (Rs. 0.32/u) and withdrawal POC rate (Rs. 0.32/u). To minimise the cost on account of PoC charges in collective transactions, IEX suggested netting of buy and sell quantum of a State. For example sell volume of a State is 40 MWhr and by volume is 100 MWhr, then the net drawl for the State is 60 MWhr. This way, the State would incur POC charges only on its net drawl quantity, thereby reducing its POC charges. Further, IEX pointed that the STOA charges paid by a State DIC is reimbursed to them in manner of offset against their LTA. However, the STOA charges paid by intra state entities embedded in the State network are socialised to the advantage of other States as per the method of offset against LTA. IEX suggested that a DIC promoting open excess should be given the benefit offset. He also requested that there should be intrastate power exchange to facilitate intra state transactions.

1.22. All the members present did not agree with the idea of netting proposed by IEX. Shri S.K. Soonee rejected the idea citing following (i) Netting is cross subsidizing in nature and shifts the responsibility of POC to another entity (ii) Cost disagreements during times of market splitting. He further said that open access gives access to a larger market and therefore offsets within a State is detrimental to its regime. Shri S.S Barapanda expressed that STOA charges collected from an embedded entity is passed on to the DICs. Shri S.A. Soman expressed that, in case injection / withdrawal is happening at the same node then in technical terms, there is netting; else there should beno netting. He further said offset benefit should be passed on immediately without lag. Chief Engg, CEA said that intra state transactions are cleared by respective SLDC as it is presumed to be used by intra state entities. However, in case of IEX transactions clearance is accorded by RLDC due to the interstate nature of the entities. Thus, both are not at par. Ms.Manju Gupta, CTU said that it is not right to treat power flowing in collective transactions to be separate from power in ISTS. Further, as long as the STOA is within the DIC LTA, benefit of offset is to be given to the state. Further it is only an assumption that all power bought by embedded state entity is from the embedded seller within state but cannot be said with certainity. Sh Jogender Behera, Advisor, CERC said that there could be possibility of gaming and change in injection/drawl due to IEX proposal and there may be changes in market behaviour of constituents.

1.23. The draft report as shared with members along with Agenda was discussed. TOR wise discussion was made as follows:

- **TOR 1: To critically examine the efficacy of the existing POC mechanism to see whether the mechanism has served it purpose as enshrined in Tariff Policy namely Sensitive to distance, the direction and quantum of flow;**

  a. Shri S.K. Soonee stated that POC has served its purpose excellently. It has led to PAN India market.Shri S.K. Soonee opined that min-max ratio should not be large.

  b. Shri S.S. Barpanda,GM NLDC opined that there is large spread between minimum and maximum transmission rates. He stated that it may be seen that principle of tariff policy as amended in January 2016 regarding minimum-maximum rates be taken care of. As per tariff policy, it should not inhibit planned development and at the same time, non-optimal transmission investment should be discouraged.

  c. Chief (Engg.), CERC sought views of PGCIL& CEA whether PoC is inhibiting planned development.

  d. Chief (Eng.), CEA stated that both points of tariff policy are compromising each other.

- **TOR 4: To assess the status of availability of data and data telemetry in order to facilitate shifting towards actual scenario than the estimated scenario as done currently.**
    a. Shri Barapanda stated that to move from estimated to actual scenario the nodal loads and individual state generation data is needed which at present is not available.
    b. Sh. Soonee suggested that truing up on actual data may not be a good option.
    c. Shri S.A. Soman stated that sensitivity analysis with estimated and actual scenario should be done to decide whether there is a need to move to actual scenario.

TOR 8: In addition the Taskforce shall also study the following and make recommendation to the Commission:

- To assess the utilization of transmission system and suggest measures to improve the utilization of transmission system;
- To assess the reactive power requirement in integrated grid and examine the adequacy of available reactive power management resources;
- To assess the available transfer capability and the measure to improve the same;
- Any other relevant issue.

a. AGM, PGCIL said any utilization of a transmission system is relative figure with respect to loadability/SIL/Thermal capability. States do not build downstream system placing a limit on line loadability.

b. Shri Soonee stated that old load center generators may be used as synchronous generators to provide reactive power. He also stated that RE generators should also be mandated to provide reactive capability.

c. Chairman stated that representative of CEA may provide details on this aspect as to steps being taken currently and suggestions for future in this regard.

d. Representative of CTU stated that series compensation may be used to improve utilisation.Chairman requested CTU to provide a writeup in this regard.

e. On Available transfer capability, Professor Soman stated that operational TTC may be determined. The roadblocks may be identified and actions to improve it may be taken by the planner. He also stated that assets should not be turned off during high voltage, rather reactive power planning should be done. He also advocated use of synchronous condenser

f. Chief Engg. CEA informed that with respect to consultant's report on ATC/TTC, the methodology of CTU, POSOCO has been validated. Further he informed that recommendation on voltage stability made by the consultants on TTC/ATC have also been adopted. He told that additional recommendation on generator, exciter, governor and PSS are under consideration.

TOR : On Methodology for calculation of losses.

POSOCO representative stated that presently losses are being calculated on a regional basis.Shri S.K. Soonee said that scheduling is done on a regional level due to regional peculiarities. He suggested each regional pecularity should not be altered for calculation of losses. Sighting the example of northern region, he said that during peak time the northern region might have a high local generation. In which case its losses will be low compared to other regions.

TOR 6: Specify reliability benefit in large connected grid and provide methodology for determination of quantum of Reliability support charges and its sharing by constituents and to provide Methodology of sharing of HVDC charges by constituents; and

TOR 7:Final Recommendations on Transmission pricing;

a. POSOCO stated HVDC is for the entire country and should be treated as a national asset.

b. Prof Soman said HVDC treatment should be done considering with and without scenario.

c. Shri S.K Soonee said HVDC gives following benefits

   (i) Bidirectional flows

   (ii) Flexibility for RE integration.

   (iii) Reliability

d. Prof. Soman stated that cost causality principle may be used which will include reliability benefit in itself. The capacity may be taken as per St. Clair's curve and reliability should be socialised.The extent of usage may be 15-20% in a particular scenario. On this n-1 reliability should be added.

e. Shri S.K Soonee said that extent of line usage should be broken in to atleast 2 or 3 components to reduce price distortion. He noted the significant difference between distribution and transmission. A distribution system is radial in configuration to keep costs low and reliability suffers, while a transmission system is double circuited or meshed to keep reliability high and costs become high as a result.

f. Ms Manju Gupta, AGM, POWERGRID stated that the flow in a particular line at any moment is decided /controlled by grid operator based on prevailing grid conditions. After grid disturbance, power flow in many lines are allowed below their capacity by grid operator.

g. Prof S.A Soman stated that line utilizations should be calculated based on the capacity and for calculation of utilisation, assets should not be switched off. He also stated that invertor specifications may be made by CEA.

3. During the deliberations of the meeting following comments of the stakeholders was discussed:-

(a) Quantum of Reliability Support Charges and its Sharing by constituents: - Prof. S. A. Somansuggested a procedure based upon N-1 contingency studies can be used to find maximum possible loading on the transmission line during contingencies. If the utilization of line is 17%, then 17% of its cost should be recovered on usage basis and 83% on postage stamp basis. In this 17%, an approach can be add another 17% as reliability component so that 34% cost is levied on usage basis and balance 66% on postage stamp basis.

(b) Actual line wise MTC vs. MTC calculated on average cost method:- It was decided that MTC calculated on average cost method is used instead of actual line wise MTC.

(c) DC Load Flow Vs. AC Load Flow:- It was decided that the existing AC load flow will be continued in place of DC load flow under the POC mechanism.

(d) Treatment of lines with cumulative Marginal participation factor less than a significant value: -It was decided that the marginal participation factor of the transmission line is less than 0.50 should be socialised to the remaining users of the transmission line.

(e) Methodology for calculation of transmission losses:-It was decided that the existing methodology for calculation of transmission losses should be continued under the POC mechanism.

(f) LTA/MTOAconsidered in computation of Slab rates and LTA/MTOA considered in RTA:-Shri S.K Sonnee, POSOCO suggested that existing Methodology for consideration of LTA/MTOA should be continued for POC mechanism.

(g) Trued-up of POC slabs rate for every Application Period:- Chief (Engg), CERC stated that estimated previous year data should be used for POC computation than trued up with actual data for every quarter.

(h) CTU / State Utilities shall arrange to provide / facilitate access of online telemetry data in a time bound manner so as to improve the accuracy of the Pricing mechanism.

(i) Increase in number of slabs or doing away with slabs: -Shri S.K Sonnee, POSOCO suggested that the existing methodology for arriving the slabs and no of slabs should be continued. For taking a view on increase in no of slabs/ doing away with slabs, suggestions were sought from CTU, POSOCO and CEA.

(j) RTDA Charges for deviation (up to 120% of LTA) should be borne by entity responsible for such deviation:-Joint Chief (Engg), stated that stakeholders have suggested that the deviation charges on account of generators should not be billed to the consumers. All the members agreed for the same.

(k) No proper check on Reactive Energy flow in PSSE &Webnet software-:-It was pointed out that the base case network taken for POC computation shows that the Power factor of almost all nodes of some of state are same and that too near unity.

Representative of POSOCO stated that most of the states arenot submitting their node wise data for POC computation so that Power factor of some of the states taken the same at all the nodes.

(l) Issues pertaining to NER:- Shri S.K Soonee, POSOCO stated that the earlier methodology of sharing of transmission charges by NER constituents under the UCPTT scheme was as per the policy decision of Ministry of Power. Since NER constituents are raising this issue, hence a decision in this regards may be taken by MOP.

(m) Transparency:-Shri S.S Barpanda, POSOCO stated that all the data pertaining to sharing of transmission charges under the POC mechanism are available at POSOCO website.

4. Shri Ravinder Gupta, Chief (Engg), CEA stated that the benefits of STOA offsetting should not go to LTA holders and offsetting should be given to all the DICs. He further stated that CEA installed various STATCOMs and analysis is done at the time of planning for reactive power management.

5. Further inputs were sought from CEA, CTU and POSOCO on the TOR of the taskforce.

1.24. The Chairperson of the taskforce demitted office on 23.7.2018. Vide Office Order dated 6.8.2018, the taskforce was continued under Chairmanship of Sh. A.S.Bakshi. A copy of the Office order is enclosed at Annexure-II.

Seventh meeting of the Task Force

1.25. Seventh meeting of the Task Force was held on 19.9.2018.Gist of discussions is as below:

1.25.1. Shri. Bakshi stated that on a few issues discussed before, no consensus has been reached yet. :

(a) HVDC charges sharing: - Whether charges should be socialised or with present method of sharing on causer pays basis or some other methodology used for HVDC charges sharing.

(b) Transmission Losses methodology.

(c) Reactive power requirement.

(d) International experiences.

(e) How to reduce charges for all States since it has increased for most of the states.

1.25.2. Mr Vijay Menghani shared New Zealand experience on transmission pricing where the transmission pricing became a very contentitous issue and went to Courts.

1.25.3. On HVDC sharing following was discussed:

(a) Representative of POSOCO stated that HVDC provides resilience to the system. Sh. S. R. Narasimhan stated that there may be reverse flow through Talcher-Kolar, Raigarh-Pugular in case of high RE in Southern region.

(b) Sh. S.K. Soonee stated that for RE integration HVDC shall be useful. Hence all HVDC should be taken as system reliability.

(c) Sh. Vijay Menghani stated that HVDC should be billed as per contracts.

1.25.4. On reactive power issue following was discussed:

(a) Shri KVS Baba, CMD, POSOCO stated that each state should take care of the gap between its estimated demand and actual demand for reactive power support. He stated that Power electronic devices are capable of providing reactive power support to the grid and to encourage such support there should be a mechanism to incentivise them. He opined that states are also capable of providing reactive power support to grid. The voltage duration curve for all the substations is available in public domain.

(b) Shri Ashok Pal, POWERGRID stated that CTU does reactive power studies for both off peak and peak case. At the time of planning both operational and anticipated/ projected data is considered in base case. Notwithstanding, many assumptions are still required in base case in view of non- availability of accurate data. He further stated that the electricity act, 2003 has also given equal responsibility to both STU and CTU and CTU cannot proceed for reactive power study without STU data. He suggested that CTU can only estimate the state data for reactive power study but STU can submit the accurate data.

(c) Shri S.K Soonee, Advisor, POSOCO raised that off peak cases should also be considered when doing reactive power studies. Load generation balance data for reactive power study should clearly show in MW terms, which state has surplus or which state has deficit. All utility-wise load generation data for reactive power study is to be made available.RE connectivity standard should be available for Renewable generating station. Ancillary service should also be available for reactive power.

(d) Shri S.R Narasimhan, ED (NLDC) stated that an experiment had been conducted in the solar park embedded in the SR region wherein it was observed that inverters were absorbing reactive power and Voltage profile was also changed for reactive power.

(e) Ms Manju Gupta, AGM POWERGRID stated that RPCs have also been doing reactive power study and states are submitting their data to RPCs.

Eighth meeting of the Task Force

1.26. Eighth meeting of the Task Force was held on 7.3.2019.The report was finalised and adopted during the meeting.

1.27. The Report is framed in four chapters. First chapter covers background of formation of taskforce and gist of the discussions during meetings of taskforce. Second chapter covers the legal framework, mechanism of transmission charges sharing prior to POC mechanism and brief of amendments done in Sharing Regulations. Third chapter briefly covers the comments of stakeholders submitted by them during 3rd meeting and through written submissions. Fourth chapter covers detailed analysis and recommendations Terms of reference wise for each Terms of reference.

Chapter 2

Current arrangement of pricing in Inter-State Transmission System

2. Introduction

ThisChapter covers historical background of transmission pricing prior to current PoC regime and the changes brought out in PoC mechanism since its implementation in 2010 till date.

2.1 Regional Postage Stamp Methodology:

2.1.1 Prior to the implementation of the Point of Connection (PoC) methodology of sharing of transmission charges for ISTS network from July 2011, the mechanism of pricing on the ISTS was based on the regional postage stamp basis. This implies that all users of a system in a region were paying the same price per MW of allocated transmission capacity.

2.1.2 The Contract path method was used for the short term bilateral transactions. As this was not conducive to the operation of Power Exchanges, a methodology similar to „point-of-connection" tariff had been adopted for Collective Transactions through Power Exchange, with uniform injection and withdrawal charges. Thus, prior to the implementation of PoC mechanism, 'postage stamp', 'contract path' and 'point-of-connection' pricing methodologies coexisted in the country for different types of transactions. The postage stamp system for sharing of transmission charges was working well until the footprint was small and the system had a high degree of acceptability among the stakeholders. However, the policy mandate of distance and direction sensitive tariff was not getting captured.Over the time country has also seen an increase in the interregional flows which has further accentuated the problem of pancaking in the earlier method. Inefficiencies, rapid growth of electricity markets, changing structure of the network and increasing complexity including multiplicity of organizations, multiple licensees, large interregional energy transfers, etc., acted as drivers for change.

2.2 Point of Connection (PoC) Methodology: Legal Framework

2.2.1 The Regulations have been made by the Central Electricity Regulatory Commission in exercise of powers conferred under Section 79(1) (c) and (d) read with Section 178 of the Electricity Act, 2003 (36 of 2003), and all other powers enabling it in this behalf. Commission is empowered under Section 79 of the 2003 Act to not only regulate inter-State transmission of electricity but also determine the tariff for inter-State transmission of electricity. The relevant portions of Section 79 are extracted as under:-

"79. (1) The Central Commission shall discharge the following functions, namely:-

…

(c) to regulate the inter-State transmission of electricity ;

(d) to determine tariff for inter-State transmission of electricity;

…

(k) to discharge such other functions as may be assigned under this Act."

2.2.2 The Central Commission is to be guided by the National Electricity Policy notified by the Central Government under section 3 of the 2003 Act, in discharge of its functions. In this regard, Section 79(4) provides as under:-

"(4) In discharge of its functions, the Central Commission shall be guided by the National Electricity Policy, National Electricity Plan and tariff policy published under Section 3."

2.2.3 The provisions of National Electricity Policy and National Tariff Policy in regards to sharing of transmission charges and losses are as follows :

(a) The National Electricity Policy under Section 3 of the Act notified vide Resolution No.23/40/2004-R&R (Vol.II) dated 12.1.2005 inter alia provides as follows:-

"To facilitate cost effective transmission of power across the region, a national transmission tariff framework needs to be implemented by CERC. The tariff mechanism would be sensitive to distance, direction and related to quantum of flow. As far as possible, consistency needs to be maintained in transmission pricing framework in inter-State and intra-State systems. Further it should be ensured that the present network deficiencies do not result in unreasonable transmission loss compensation requirements."

(b) The Tariff Policy notified vide Govt. of India Ministry of Power Resolution No. 23/2/2005-R&R (Vol.III) dated 6.1.2006 by the

Central Government under Section 3 of the 2003 Act, inter alia, provides as under:-

"7.1. ….

(2) The National Electricity Policy mandates that the national tariff framework implemented should be sensitive to distance, direction and related to quantum of power flow. This would be developed by CERC taking into consideration the advice of the CEA. Such tariff mechanism should be implemented by 1st April 2006.

(3) Transmission charges, under this framework, can be determined on MW per circuit kilometer basis, zonal postage stamp basis, or some other pragmatic variant, the ultimate objective being to get the transmission system users to share the total transmission cost in proportion to their respective utilization of the transmission system. The overall tariff framework should be such as not to inhibit planned development / augmentation of the transmission system, but should discourage non-optimal transmission investment."

"7.2..(1) Transactions should be charged on the basis of average losses arrived at after appropriately considering the distance and directional sensitivity, as applicable to relevant voltage level, on the transmission system. Based on the methodology laid down by the CERC in this regard for inter- state transmission, the Forum of Regulators may evolve a similar approach for intra-State transmission."

(c) The Tariff Policy was amended vide Notification dated 28.1.2016. The amended policy provides as follows:

"7.1….

(2) The National Electricity Policy mandates that the national tariff framework implemented should be sensitive to distance, direction and related to quantum of power flow. This has been developed by CERC taking into consideration the advice of the CEA. Sharing of transmission charges shall be done in accordance with such tariff mechanism as amended from time to time.

(3) Transmission charges, under this framework, can be determined on MW per circuit kilometer basis, zonal postage stamp basis, or some other pragmatic variant, the ultimate objective being to get the transmission system users to share the total transmission cost in proportion to their respective utilization of the transmission system. The 'utilization' factor should duly capture the advantage of reliability reaped by all. The spread between minimum and maximum transmission rates should be such as not to inhibit planned development/augmentation of the transmission system but should discourage non-optimal transmission investment."

(d) The above statutory provisions and policy guidelines enjoin upon the Central Commission to develop and implement a national transmission tariff framework sensitive to distance, direction and related to quantum of flow. In compliance of the said mandate, the

Commission undertook the exercise to frame regulations on sharing of transmission charges and losses.

2.3 Procedure of framing the Regulations

2.3.1 The Commission followed a detailed process of public consultation in the finalization of these regulations. The first staff paper on the subject was put on the Commission's website on 15.5.2009. Thereafter the Commission conducted workshops in Delhi, Kolkata, Guwahati and Bangalore to explain the methodology to various stakeholders. This was followed by public hearing on 29.7.2009 on the subject. The Commission deliberated on the suggestions received and directed the staff to incorporate the accepted suggestions. Re-computation of the methodology was done by considering (i) the Basic Network of 2008-09 and 2011-12 for NEW grid and SR grid separately (ii) the pricing mechanism was based on AC load Flow analysis instead of DC load flow (iii) loss allocation was done using the same methodology (iv) Average Historical YTC was considered for lines at each voltage level instead of Benchmark YTC, and (v) by considering slack buses based on the Average Participation Method. Based on the above, revised paper and draft regulations were posted on the CERC website for public comments.

2.3.2 The Commission conducted a workshop in New Delhi on 5.4.2010 to explain the methodology to various stakeholders, which was attended by more than 100 participants from CEA, STUs, SEBs, and private sector players, NLDC / SLDCs, RPCs and PSUs. Subsequently, public hearing was conducted on 13.4.2010. Finally detailed discussions were held with NLDC which has been designated as the Implementing Agency. Various implementation issues were further discussed with representatives from RPCs, SLDCs, CTU and NLDC before finalization of these regulations.

2.3.3 The Central Electricity Regulatory Commission (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010 ("the Principal Sharing Regulations")were notified by the Commission on 15.6.2010 and were published in the Gazette of India on 16.6.2010. The Principal Sharing Regulations came into force from 1.7.2011.

2.4 PoC mechanism –sensitive to distance, direction and quantum of flow

2.4.1 Under the CERC (Sharing of Inter-state transmission charges & losses) Regulations 2010, sharing of transmission charges in respect of Inter-State Transmission System (ISTS) is done in the country using a scientific method which is sensitive to distance, direction and quantum of power flow as explained below:

(a) Distance :

The methodology used for allocation of transmission charges among various users is based on scientific method of Load Flow studies. In this the Load Generation balance scenario in a synchronously connected grid is simulated using the quantum of injection and drawls figures given by users called the Designated inter-State transmission System Customers (DICs). Electricity generated by a generator reaches a drawee customer not through a single line but through the meshed network of transmission lines. In the present methodology, through load flow studies it is first found that in a particular scenario called base case, how much power is drawn by say Orissa at each node of inter-State Transmission system (ISTS). As a typical example, Orissa draws power from ISTS at six nodes and on each node the quantum of power drawn (in MW) through the transmission lines is found. The tariff of these transmission lines is decided by the Central Commission. The tariff of transmission lines of the same voltage and conductor configuration is pooled together to find average tariff for each voltage level and conductor configuration of line in Rs. per circuit km. Transmission charges should be payable based on distance, direction and quantum of power flow factor which decides the transmission charge is relative location of load and generation. If for some quantum of load, a generator is available nearby, then, in accordance with the laws of electricity; less number of transmission lines will be used to feed this load, as compared to the load where a generator is far off; hence less would be transmission charge applicable. Moreover, the distance travelled is the electrical distance, i.e. the length of electric lines used. As transmission charge is expressed in Rs. per circuit kilometer (ckm), if power is coming through a long circuit, it will use a larger length of transmission line or more number of lines, hence, the transmission charges are sensitive to distance of power flow.

(b) Direction:-

The concept of direction sensitivity is introduced by adopting the principle that if a particular power flow is against the normal flow of power in the base case on that line, it would not be charged the transmission charge for that line, as it is actually decongesting the line. The Software designed by IIT Mumbai takes care of this in its algorithm and does not charge for this opposite direction flow.

(c) Quantum of Power Flow

The earlier system of sharing of transmission was done on a Regional pooled basis and was dependent only on the quantum of allocation of power / LTA and quantum of contracts. However in the present methodology the charges are allocated to each node on the basis of quantum of drawal or injection at that node. So, the greater the drawal of power at a node the greater the transmission charges that would become payable. Hence the transmission charge is sensitive to the quantum of power drawls at a node and it is also sensitive to quantum of power flow. How this methodology is actually implemented in the software it is necessary to know the following:-

a. Power at a particular node is coming from which Generator – nearby or far and how much from each Generator – A scientific method called Average participation method is used by tracing power flows between Generator and Loads.

b. To draw that much power, which transmission lines are being used and how much by each node as each line is carrying power for more than one node -a scientific method called Marginal Participation Method is used. A 765 kV or 400 kV line (analogy trunk line or highway) carries large quantity of power and out of this, at various nodes, lesser capacity lines or branches (analogy State road) carry lesser quantum of power to other nodes. The software calculates the usage based transmission charge for each node. The nodes are aggregated into zones (which represent a State) and the sum total of charges for all such nodes in the State are taken as the PoC Charges of the State. Transmission charges computed by this method are sensitive to distance, direction and quantum of power flow.

(a) Based on the Yearly Transmission Charges of ISTS Transmission Licensees and transmission losses in the ISTS network, the Implementing Agency computes the Point of Connection charges and Loss Allocation Factors for all DICs:

(i) Using load-flow based methods; and

(ii) Based on the Point of Connection Charging method.

2.4.2 The mechanism for sharing of ISTS transmission charges and ISTS losses as well as the procedure thereof as per Principal Sharing Regulations is as under:

Mechanism to share ISTS transmission charges as per Principal Regulations

(a) The sharing of ISTS transmission charges between Designated ISTS Customers is computed for an Application Period and is determined in advance and is subject to periodic true-up.

(b) The sharing of ISTS transmission charges is based on the technical and commercial information provided by various Designated ISTS Customers, ISTS Transmission Licensees, and any other relevant entity, including the NLDC, RLDCs and SLDCs to the Implementing Agency. In the event of such information not being available within the stipulated timeframe or to the level of detail required, the Commission may authorise the Implementing Agency to obtain such information from alternative sources as per the procedure as may be approved by the Commission in this behalf.

(c) The mechanism for sharing of ISTS charges shall ensure that

(i) The Yearly Transmission Charge of the ISTS Licensees are fully and exactly recovered; and

(ii) Any adjustment towards Yearly Transmission Charge on account of change in commissioning schedule of elements of the power system and change in factors constituting the transmission charge, approved by the Commission. e.g., FERV, Changes in interest rates shall be fully and exactly recovered etc., as specified subsequently in these regulations.

(d) The Point of Connection transmission charges are computed in terms of Rupees per MegaWatt per month. The amount to be recovered from any Designated ISTS Customer towards ISTS charges shall be computed on a monthly basis as per these regulations. The Point of Connection transmission charges for short term open access transactions shall be in terms of Rupees per MegaWatt per hour and shall be applicable for the duration of short term open access approved by the RLDC/NLDC.

Mechanism of sharing of ISTS losses as per Principal Regulations

(a) The schedule of electricity of Designated ISTS Customers shall be adjusted to account for energy losses in the transmission system as estimated by the Regional Load Despatch Centre and the State Load Despatch Centre concerned. These shall be applied in accordance with the detailed procedure to be prepared by NLDC within 30 days of the notification of these regulations. The losses shall be apportioned based on the loss allocation factors determined using the Hybrid methodology.

(b) The sharing of ISTS losses shall be computed based on the information provided by various Designated ISTS Customers, ISTS Licensees, and any other relevant entity, including the NLDC, RLDCs and SLDCs and submitted to the Implementing Agency.

Provided that in the event of such information not being available within the stipulated timeframe or to the level of detail required, the Commission may authorize the Implementing Agency to obtain such information from alternate sources as may be approved for use by the Commission.

(c) The applicable transmission losses for the ISTS shall be declared in advance and shall not be revised retrospectively.

(d) The Implementing Agency may, after seeking approval of the Commission, conduct studies from time to time to refine the ISTS loss allocation methods.

2.5 Amendments to the Principal Sharing Regulations

2.5.1 Five amendments have been issued till date duly following the consultative process. The first, second, third, fourth and fifth amendment became effective from 24.11.2011, 28.3.2012, 1.5.2015, 1.6.2015 and 14.12.2017 respectively.

2.5.2 **Salient features of the First Amendment to CERC (Sharing of Interstate Transmission charges and losses Regulations) 2010**

The Principal Regulations were amended on 24.11.2011 after due consultative process. During the process of finalizing the appropriate mechanisms and procedures for implementation of the Sharing Regulations, a number of problems were encountered by the Implementing Agency, the Central Transmission Utility (CTU) and the State Utilities. They wrote letters and made presentation to the Commission highlighting these problems and requested the Commission for Removal of Difficulties under Regulation 21 of the Sharing Regulations. For smooth implementation of the Sharing

Regulations from 1.7.2011, the Commission issued orders dated 4.4.2011, 2.6.2011, 22.6.2011 and 29.6.2011 under Regulation 21 of the Sharing Regulations. In the said orders, the Commission directed the Staff to carry out suitable amendments in the Sharing Regulations. Accordingly, First amendment was brought out to cover the aspects as detailed below:

(a) In the definition of Approved Injection, the word 'contract' have been replaced by the term 'Access' in case of Long-term Access and 'Open Access' in case of Medium-term since long-term access given to the generators/Independent Power Producers (IPPs) by the Central Transmission Utility (CTU) in some cases does not match with the Power Purchase Agreements (PPAs)/ contracts signed with the States/bulk consumers.

(b) Since CTU and some States wanted the billing and payment of charges to be done directly to the distribution companies, as was being done earlier, the Commission allowed the same as under the "Power to Remove Difficulties" order dated 2.6.2011.

(c) Point of Connection nodal and zonal rate are to be computed for one representative scenario of the year based on the yearly average. This provision was made because despite the best efforts by the Implementing Agency, many DICs were not able to provide complete data for the five scenarios, peak and off-peak separately, which were required for computation of POC charges. Under the circumstances, computation based on one average scenario was the best option available.

(d) There are generators which have been granted Longterm Access based on the targeted beneficiaries in the same Region and/ or to other Regions. The injection PoC for LTA to a target region granted to a generator was allowed to be offset by the injection PoC for MTOA to any region.

(e) For non-ISTS lines certified by RPC to be included in POC calculations, it was decided that all lines which were already certified by RPCs as on the date of publication of the Sharing Regulations and not on the date of implementation of the Sharing Regulations would continue. For lines certified for the new scenario, when system studies would next be done, the new methodology would be used

2.5.3 **Salient features of the Second Amendment to CERC (Sharing of Interstate Transmission charges and losses Regulations) 2010:**

(a) The Commission modified regulations to include 3 slab system which were hitherto forming part of Commission's Orders.

(b) The overload capability of generating stations is not to be considered while calculating its Long term Access.

(c) YTC is to be revised on a six monthly basis i.e. on 1stApril and 1stOctober in the first full year and subsequently on quarterly basis, i.e. on 1stApril, 1stJuly, 1stOctober and 1st December.

(d) An inter-State Generating Station (ISGS) directly connected to the 400 kV inter-State Transmission System shall be treated as a separate zone

(e) The entire YTC of the Talcher - Kolar HVDC transmission link to be borne by the DICs of the Southern Region by scaling up their PoC charges. However, the PoC injection rate for the allocated share from Talcher – II station to the State of Odisha shall be the PoC injection rate of Talcher – I station: Provided that after the entire country is synchronously connected, the cost of all the HVDC systems shall be borne by all the DICs in the country by scaling up the YTC calculated without including the HVDC costs

2.5.4 **Salient features of the third Amendment to CERC (Sharing of Interstate Transmission charges and losses Regulations) 2010:**

(a) The draft amendment seeking comments/ suggestions/ observations from the stakeholders/public at large was hosted on the Commission's website along with an Explanatory Memorandum on 7.2.2014. Comments were received from 27 stakeholders, organizations, and individuals, etc., which included State Power utilities, Central Electricity Authority (CEA), Central Transmission Utility (CTU), Power System Operation Corporation (POSOCO), Inter-state transmission licensees, generating companies in central sector and private sector, including associations. Thereafter, the Commission conducted public hearing on 12.6.2014. Nine (09) organizations/individuals including POSOCO, CTU, generating companies, associations and individuals made oral submissions and /or presentations during the public hearing. After due considerations of the comments/ suggestions/ objections received and detailed discussions with the statutory authorities like Central Electricity Authority and Central Transmission Utilities as well as National Load Despatch Centre which has been assigned the role and responsibility of Implementing Agency under the Sharing Regulations, the Commission has finalized and notified the Third Amendment to the Sharing Regulations. The Statement of Reasons seeks to discuss in detail the rationale behind the various provisions included in the Third Amendment to Sharing Regulations.

(b) Sharing of transmission charges commensurate with usage close to maximum actual usage by way of (i) calculation of charges on only withdrawal nodes and for generators with LTA to target region,(ii) shift from average (energy based) base case to maximum injection/drawal based base case, (iii) removal of uniform charge, (iv) spreading number of slabs from three to nine, (v) elimination of truncation of network, and (vi) off set of transmission charges commensurate to STOA transactions in any region.

(c) The concept of reliability support charge has been introduced in view of the fact that DICs getting benefits which accrue to them by virtue of operating in an integrated grid. The Commission has for the present taken a decision to allocate 10% charges as Reliability Support Charges. However the Commission would like to have a better picture in this regard and hence has directed POSOCO to prepare a base paper in consultation with CEA and CTU on quantification of reliability benefit in a large inter-connected grid such as ours including market risk mitigation based on international experience.

(d) A separate treatment for sharing of charges of HVDC systems, being a different type of transmission asset, is unavoidable as with the marginal participation method, HVDC cost cannot be allocated. Various methods for sharing of transmission charges of HVDC systems, namely With and Without method, uniform distribution of the charges among all the DICs and sharing by withdrawing DICs of regions for whom such HVDC systems were set up, were considered and it was concluded that the charges for HVDC systems shall now be borne by the withdrawing DICs of region(s) for whom the asset has been created. In the event of better projection and appreciation of benefit of HVDC systems in due course, keeping in view evolving methodologies worldwide, the Commission may consider the proposal for review of sharing of transmission charges of HVDC system. NLDC may in consultation with CEA, CTU, IITs and international consultants submit a technical report for various solutions for allocation of cost for HVDC system in India supported by adequate calculations.

(e) Introduction of nine slab rates in place of three slab rates to approximate the transmission charge liability of a DIC to its actual usage

2.5.5 Salient features of the Fourth Amendment to CERC (Sharing of Interstate Transmission charges and losses Regulations) 2010

(a) The Government of India, Ministry of Power has sanctioned the "Scheme for utilisation of gas based power generation capacity" vide O.M. No.4/2/2015-Th.I dated 27.3.2015. The scheme envisages supply of imported spot RLNG "e-bid RLNG" to the stranded gas based plants as well as the plants receiving domestic gas. The scheme is eligible for stranded gas based plants and those plants receiving domestic gas whose actual average PLF achieved during April-January 2014-15 was below the target PLF. The scheme provides for exemption from transmission charges and losses and support from PSDF.

(b) In order to facilitate implementation of the Scheme, the Commission amended the Central Electricity Regulatory Commission (Sharing of inter-State Transmission Charges & Losses) Regulations, 2010 to exempt transmission charges and transmission losses for the use of ISTS network to incremental gas based generation from e-bid RLNG for the years 2015- 16 and 2016- 17.

2.5.6 Salient features of the Fifth Amendment to CERC (Sharing of Interstate Transmission charges and losses Regulations) 2010:

(a) The existing provision has been modified to extend waiver of inter-State transmission charges and losses for the generation projects based on solar resources till 31.12.2019.

(b) A provision has been added to waive inter-State transmission charges and losses for the generation projects based on wind resources till 31.3.2019

(c) The waiver in respect of generation projects based on solar and wind resources has been provided only for projects awarded through competitive bidding and signed PPAs with DISCOMs for sale of power to meet their RPO obligation.

(d) The existing provision, which provided for adjustment of charges payable for drawl of start-up power and injection of infirm power in the next quarter, has been modified for adjustment in the month following the month of billing, in proportion to the billing of the DICs during the concerned month replacing earlier provision of quarterly adjustment.

(e) Earlier, there was no clarity in the Sharing Regulations for billing of DICs having LTA to target region and for which PoC rate has not been determined. In order to clarify this, a provision has been introduced that for DICs having LTA to target region and PoC rates has not been determined, billing of such DICs shall be done at Average PoC rate of the target region.

(f) The existing provisions related to offsetting of Medium Term Open Access (MTOA) and Short Term Open Access (STOA) availed by Long Term Customers having Long Term Access (LTA) granted to target region were amended to bring clarity that the adjustment shall be done for the quantum of MTOA/STOA by LTA customers rather than charges paid by the LTA customers for MTOA/STOA for a to any region limited to granted quantum of LTA

2.6 Need for Review of the Point of Connection (PoC) Methodology

2.6.1 The Principal Sharing Regulations Commission notified by the Commission on 15.6.2016 provides that the said regulations shall remain in force for 5 years from the date of commencement unless reviewed earlier or extended by the Commission. Further, vide order No. L-1/44/2010-CERC dated 31st March, 2011, the Commission observed that the Principal Sharing Regulations shall come into force with effect from 1.7.2011. The relevant portion of the Principal Sharing Regulations reads as under:

> "(3) These Regulations shall come into force from 1.7.2011, and unless reviewed earlier or extended by the Commission, shall remain in force for 5 years from the date of commencement specified above."

2.6.2 Further, vide Gazette notification dated 22.6.2016, the applicability of the Principal Sharing Regulations as amended from time to time was extended for another 5 years with effect from 1.7.2016 unless reviewed earlier or extended by the Commission. The relevant portion of the said gazette notification dated 22.6.2016 reads as under:

"…….

Whereas the Commission considers it necessary to continue operation of the Principal Regulationsas amended from time to time for a further period of 5 years for the purpose of sharing of inter-State Transmission charges and losses.

And, now, therefore, it is notified for the information of all concerned that the Central Electricity Regulatory Commission (Sharing of Inter-state Transmission Charges and Losses) Regulations, 2010 as amended from time to time shall remain in force for period of 5 years with effect from 1.7.2016 unless reviewed earlier or extended by the Commission."

2.6.3 In the mean time, Sates like Assam, Maharashtra, Rajasthan and Odisha have also raised their concerns on existing PoC framework.

2.6.4 Accordingly, the Commission decided to constitute a Task Force to examine the PoC framework to address the concerns of all the stakeholders.

Chapter-3

3 Summary of Comments/Suggestions by Stakeholders on the existing Point of Connection (PoC) methodology of Sharing of Transmission Charges

3.1 Deliberation during the meeting of the Task Force

3.1.1 During the 1st meeting of the Task Force held on 26th July, 2017, it was decided that the suggestions and comments of the stakeholders will be invited on the existing framework of PoC transmission charges.

3.1.2 The Commission vide Public Notice dated 28.7.2017, invited comments of the stakeholders and other interested persons on the framework of Point of Connection (PoC) Charges. A copy of aforesaid Public Notice dated 28.7.2017 is enclosed at ***Annexure-VII***. Seventeen (17) stakeholders have submitted their comments/ suggestions on framework of Point of Connection (PoC) Charges.

3.1.3 The salient issues raised by abovementioned stakeholders are as under:

(a) BRPL, BYPL, TANGEDCO and TPDDL have submitted that PoC Charges are computed on load flow where as HVDC Charges are determined on LTA/MTOA. HVDC rate should also be calculated based on demand

(b) BRPL, BYPL, TANGEDCO and TPDDL have submitted that HVDC charges should be socialized

(c) BRPL, BYPL, TANGEDCO and TPDDL have submitted that HVDC rates for MTOA and STOA customer should be in line with the LTA of customer

(d) BRPL, BYPL and TPDDL have submitted that States should be directed to sign LTA corresponding to their peak demand

(e) BRPL, BYPL and TPDDL have submitted that Penalty in case of LTA less than peak demand

(f) TANGEDCO has submitted that CTU / State Utilities shall arrange to provide / facilitate access of online telemetry data in a time bound manner so as to improve the accuracy of the Pricing mechanism.

(g) GRIDCO, BRPL, BYPL, MSEDCL, TANGEDCO and TPDDL have submitted that Cost towards renewable integration should not be loaded on the DICs and billing of renewable power transmission should be done as separately

(h) GRIDCO, BRPL, BYPL, MSEDCL, TANGEDCO and TPDDL have submitted that effect of such large scale integration of RE & other distributed energy sources need to be quantified & reflected in PoC regime

(i) GRIDCO, BRPL, BYPL, MSEDCL, TANGEDCO and TPDDL have submitted that redesign the methodology for equitable allocation of transmission charges for RE

(j) GRIDCO, BRPL, BYPL, MSEDCL, TANGEDCO and TPDDL have submitted that Cost of transmission assets being created for transmission of Renewable energy should not be socialized and should be recovered only from the intended beneficiaries.

(k) GRIDCO and MSEDCL have submitted that Slabbing should be removed

(l) GRIDCO, MSEDCL, TPDDL and Rajasthan have submitted that PoC charges should be calculated considering actual usage of transmission system

(m) GRIDCO, MSEDCL, TPDDL and Rajasthan have submitted that there should be comparison of Maximum Withdrawal occurred in actual scenario vis-a-vis projected data considered for PoC computation and trued-up for every application period.

(n) MSEDCL and GUVNL have submitted that Charges for deviation (up to 120% of LTA) should be borne by entity responsible for such deviation

(o) MSEDCL has submitted that no auto check in both PSSE & Webnet Software for limit for exceeding maximum electrical parameters (more than electrical parameter)

(p) MSEDCL has submitted that no proper check on Reactive Energy flow in PSSE & Webnet software

(q) GUVNL has submitted that reliability support charges should be corresponding to 60% of ATC.

(r) GRIDCO has submitted that reliability benefit should be quantified for all users of the grid

(s) GRIDCO has submitted that impact of open access consumers need to considered while calculating PoC charges

(t) TPDDL and GRIDCO have submitted that every transmission scheme seeking regulatory approval should contain the details regarding its effect on the transmission capacity of the existing network along with the cost benefit analysis, incremental effect on the tariff and details regarding the beneficiaries accountable to pay the transmission charges of the same

(u) TPDDL has submitted that no credit pertaining to MTOA/STOA transactions should be passed on to customers who are not having LTA commensurate with their Peak Demands

(v) TPDDL has submitted thatan independent agency/ Existing agency to monitor the performance/degree of utilization of the transmission system vis' a vis' its technical and declared capacity.

(w) TPDDL has submitted that Concerned state utilities/DISCOMS should also be involved in ISTS planning

(x) GRIDCO, TANGEDCO, Shri Bajrang Power and Ispat Limited have submitted that Scaling should be avoided to recover cost of unused/under-utilized lines

(y) GRIDCO, TANGEDCO, Shri Bajrang Power and Ispat Limited have submitted that Concessional transmission charges for under-utilized transmission lines

(z) APDCL has submitted that entire NER to be considered as a block and PoC slab may be allotted on the basis of load profile of the region

(aa) APDCL has submitted that Intra-regional sharing of the charges may be made in line with previously applicable UCPTT Charges

(bb) TANGEDCO has submitted that A comprehensive method like locational based marginal pricing method suitably modified to fit in Indian scenario would be capable of addressing the shortcoming of the present methodology in view of the planned developments and market conditions

(cc) BSP(H)CL, GRIDCO, BRPL, MSEDCL and BYPL have submitted that for transparency

a. DICs should be provided Webnet Use software free of cost

b. CTU should share detailed principle & calculation for determination of indicative cost

c. Calculation for deriving average cost from indicative cost should also be shared with all DICs

d. Data uploaded by Implementing Agency should be more systematic & user friendly

(dd) TPDDL has submitted that every investment proposal should be made available in the public domain and details should be provided to the intended beneficiaries

Chapter 4

Analysis of issues and recommendations

4.1 Introduction

The chapter covers analysis by the Taskforce on the Terms of reference based on literature survey, market data and discussions at the Taskforce meetings.

TOR 1: To critically examine the efficacy of the existing PoC mechanism to see whether the mechanism has served its purpose as enshrined in Tariff Policy namely sensitive to distance, direction and quantum of flow;

4.2 PoC Framework – Sensitive to Distance & Direction and related to Quantum of Flow

4.2.1 The detailed legal framework and concept of distance, direction and quantum of flow has been conceptualised in the Regulations and detailed in chapter-2 in this report.whether the current mechanism is actually distance, direction and quantum of flow sensitive?

4.2.2 To analyse whether the current mechanism is sensitive to distance, direction and quantum of flow, example of three states which are generation intensive are considered viz Himachal Pradesh, Tripura and Tamil Nadu. The latest PoC base case for Q3 2018-19 have been considred with YTC under PoC as Rs. 2315 Cr. and LTA/MTOA of 93936 MW. The charges payable under PoC (only the PoC component without considering reliability and HVDC) is compared with uniform rate which would be payable in case transmission charges are shared based on LTA. The charges based on regional postage stamp were payable on the basis of LTA of a State. Since the pool cost of each region as on date is not available due to implementation of PoC Regulations, a uniform rate has been determined considering all India YTC (same as that considerd for PoC) divided by All India LTA.

Table 1: Comparison of PoC charges vis vis uniform postage stamp charges for select states

Zone Name	LTA (MW)	ISTS drwal (MW)	PoC Slab rate as per CERC Order for Q3 2018-19 (Rs/MW/Month)	Uniform rate w.r.t LTA (Rs/MW/ month)	Normal PoC charges Q3 2018-19 (Rs. Cr.)	Charges with LTA-uniform rate (Rs Cr.)	Difference in charges payable (%) in case of POC vis a vis Uniform rate with LTA
HIMACHAL	1759	661	63070	246442	11.09	43.35	291%
TRIPURA	365	93	63070	246442	2.30	9.00	291%
TAMIL NADU	8460	5570	110113	246442	93.16	208.50	124%

4.2.3 It is observed that charges payable by Himachal reduces by 291 % under current mechanism of PoC. Let us see the generation projects from where Himachal Pradesh actually consumes the power under load flow studies.Study was done on base case of Q3 (2018-19).

Table 2: Percentage share of Generators in total load of Himachal Pradesh

Generator	% share
SAINJ	1.6025
KOLDAM	4.6304
PARBTI-3	9.0541

Generator	% share
KARCHAMW	0.6310
RAMPUR2	7.5198
NATHPA4	7.9725
CHAMERA-2	0.0134
CHAMERA-1	0.0373
BASPA4	0.0395
ADHYDRO	6.6304
PONG1	7.5921
CHAMER-3	0.0164
DEHAR	16.8977
BHAKRA_R	0.0006
BHAKRA_L	0.0006
BHABA2	5.2697
BUDHIL	0.0044
MALAN-II	3.919622
LARJI1	4.9271487
PALAMPUR	0.7972448
GIRI1	2.6110309
BASSI11	2.6180188
KANGRA1	1.5226513
MALANA1	6.7107585
BAJAURA1	0.1691836
BHAKRA-L	0.0004127

It is observed that 91% of total loads are served by generating stations within Himachal Pradesh. Balance load is served from following stations:

Table 3: Percentage share of balance Generators in total load of Himachal Pradesh

JOGINDERNAGA	2.2846
CHIBRO-H	2.1946
RSD	2.1398
KHODRIHE	0.9022
RAJPURA_TH	0.5586

4.2.4 Himachal Pradesh has contracts with following stations

Table 4: Contracts of Himachal Pradesh for Q3 (2018-2019)

Generation project	Access(MW)
Naphtha Jhakri	540.49
Baspa	300
Koldam HEP	221.31
Rampur HEP	170.61
Chamera-I HPS	79.49
Parbati III	66.79
Chamera-II HPS	46.45
Rihand-I STPS	34.04
Rihand-III STPS	33.94
Rihand-II STPS	33.08
Chamera III	29.67
Dadri NCGPS	24.35
Kahalgaon - II	21.63
Auraiya GPS	21.47
Bairasul	21.45
Anta GPS	14.64
RAPP-C	13.2
URI HPS	12.85

4.2.5 **Analysis and Recommendations of the taskforce**

(a) It can be seen that LTA of Himachal Pradesh is much higher than its ISTS drawal in Quarter 3, 2018-19. The charges are lower under current PoC mechanism since it is consuming most of power from generations located within Himachal or nearby the State.

(b) Similar analysis was also carried out for Tamil Nadu and Tripura where similar results are achieved.

(c) It can be concluded from above that the current mechanism is distance and Quantum sensitive since Himachalis consuming power from nearby sources and hence power travels less distance. Further its actual ISTS drawal is only 38% of its LTA. Under the present mechanism it is levied charges corresponding to its ISTS drawal only. Hence the mechanism is sensitive to quantum of flow.

(d) To analyse if the mechanism is sensitive to direction also, a comparison has been made of charges leviable for States with similar ISTS drawal but different charges.

Table 5: Few states with their LTA and ISTS drawal

State	LTA(MW)	ISTS Drawal(MW)	PoC charges (Rs. Cr.)
Jammu Kashmir	2060	655	22.69
Himachal Pradesh	1759	661	11.09
DNH	989	714	34.17

It is observed that Jammu and Kashmir is levied RS. 22.69 Cr (almost double of Himachal) for similar ISTS drawal at 655 MW. Similarly DNH is levied Rs. 34 Cr. since these states donot have generation within the State and hence the load increase will not relieve the transmission. Due to generation centric condition of Himachal etc the charges leviable are less as compared to other States with similar drawal pattern.

Hence the mechanism is sensitive to direction.

4.3 Whether current mechanism has inhibited planned development or promoted planned development of transmission system

4.3.1 Representative of CEA has submitted that the report of 19th Electric Power Survey (EPS) was published by CEA in Jan. 2017. Prior to that load projections as per 18th EPS was considered in transmission planning. The transmission system was planned considering the all India load projection of 283 GW as per 18th EPS for time frame of 2021-22. However as per 19th EPS the All India load projection for 2021-22 time frame is 226 GW. Due to adequacy of already planned / under implementation transmission system to handle 283 GW, inter-state transmission system is being planned to meet specific requirements only such as to meet the operational constraints, specific request from STUs, evacuation of renewable generation addition etc. The new ISTS proposals are discussed and agreed in the various meetings of regional standing Committee on Transmission and then put up to National Committee on Transmission / Empowered Committee on

Transmission for implementation through TBCB / RTM by POWERGRID/TSP. The planned development of ISTS was going on smoothly, however, recently, some STUs has shown their reluctance to connect / integrate ISTS planned for evacuation of renewable power with intra state transmission system because of anticipated PoC implication. In cases, where state have major share in a inter-state generating station / IPP, the states are interested in having their own evacuation system, so that they can draw their share of power from generation switchyard itself to avoid PoC quoting CERC order.

4.3.2 Recently a few states have raised issues with regards to augmentation of transmission system associated with renewables. Such resistance was due to non-clarity of cost implications of the policy of waiver of transmission charges and losses for specified renewable projects.

4.3.3 The taskforce observes that the current mechanism has not inhibited the development of transmission system and has rather led to development of transmission system which grew @20% CAGR. The congestion is almost nil with single market price across India for most of the time.

4.4 PoC Mechanism – Experience with the mechanism.

4.4.1 Let us see the response of different States with PoC mechanism since July 2011 when the CERC (Sharing of inte-state transmission charges and losses) Regulations, 2010 became effective. Immediately on notification of Regulations, Bihar, Jharkhand, West Bengal and Maharashtra approached respective high courts challenging the Regulations on few aspects. The basic contention raised by Bihar, Jharkhand and West Bengal was that due to 3 slabs the mechanism is not achieving what is envisaged as per the Regulations i.e the mechanism is not distance, direction and quantum sensitive. The mechanism was modified vide 3rd amendment dated 4.4.2015 vide which methodology of slabbing was modified and slabs were increased from 3 to 9 to make the mechanism reflect sensitivity to distance, direction and quantum of flow. We have already shown by example how the current mechanism achieves these objectives.

However it is observed that few states have raised issues regarding high PoC rates and that there should be less slabs or a uniform rate. An analysis was carried out on impact analysis if uniform rate based on LTA would have been there for a particular quarter.

Table 6: Comparison of charges under present PoC vs Unifrom charges simulated for a quarter

Entity	Withdrawal LTA (MW)	Cost Uniform (CU)	% MW CU/ Total CU	Cost PoC (CP)	% Rs CP/Total CP	Differnce (Uniform-PoC)	Diff (%MW-%-RS)
Delhi	5215	₹ 1,33,56,11,969	5.8	₹ 70,79,05,106	3.1	₹ 62,77,06,863	2.7
UP	9754	₹ 2,48,70,01,598	10.8	₹ 2,49,82,55,130	10.8	-₹ 1,12,53,532	0
Punjab	4609	₹ 1,17,44,17,421	5.1	₹ 63,03,70,039	2.7	₹ 54,40,47,382	2.4
Haryana	3665	₹ 94,41,39,496	4.1	₹ 1,19,81,76,784	5.2	-₹ 25,40,37,288	-1.1
Chandigarh	315	₹ 6,90,83,378	0.3	₹ 1,43,86,893	0.1	₹ 5,46,96,485	0.2
Rajasthan	4083	₹ 1,03,62,50,666	4.5	₹ 1,71,75,11,744	7.5	-₹ 68,12,61,078	-3
HP	1759	₹ 46,05,55,851	2	₹ 7,30,94,327	0.3	₹ 38,74,61,524	1.7
J&K	2060	₹ 52,96,39,229	2.3	₹ 20,20,23,610	0.9	₹ 32,76,15,619	1.4
Uttarakhand	967	₹ 25,33,05,718	1.1	₹ 27,65,98,988	1.2	-₹ 2,32,93,270	-0.1
Gujarat	5734	₹ 1,47,37,78,725	6.4	₹ 2,01,53,71,222	8.8	-₹ 54,15,92,497	-2.4
Madhya Pradesh	6703	₹ 1,72,70,84,443	7.5	₹ 1,71,47,88,524	7.4	₹ 1,22,95,919	0.1
Maharashtra	6466	₹ 1,65,80,01,065	7.2	₹ 2,78,05,75,211	12.1	-₹ 1,12,25,74,146	-4.9
Chhattisgarh	1719	₹ 43,75,28,059	1.9	₹ 18,23,67,788	0.8	₹ 25,51,60,271	1.1
Goa-WR	460	₹ 11,51,38,963	0.5	₹ 11,16,63,654	0.5	₹ 34,75,309	0
D&D	358	₹ 9,21,11,170	0.4	₹ 11,14,42,298	0.5	-₹ 1,93,31,128	-0.1
DNH	989	₹ 25,33,05,718	1.1	₹ 36,07,16,202	1.6	-₹ 10,74,10,484	-0.5
West Bengal	2041	₹ 52,96,39,229	2.3	₹ 48,75,44,104	2.1	₹ 4,20,95,125	0.2

Entity	Withdrawal LTA (MW)	Cost Uniform (CU)	% MW CU/ Total CU	Cost PoC (CP)	% Rs CP/Total CP	Differnce (Uniform-PoC)	Diff (%MW-%-RS)
Orissa	1405	₹ 36,84,44,681	1.6	₹ 12,20,36,869	0.5	₹ 24,64,07,812	1.1
Bihar	3220	₹ 82,90,00,533	3.6	₹ 1,06,60,84,037	4.6	-₹ 23,70,83,504	-1
Jharkhand	830	₹ 20,72,50,133	0.9	₹ 14,16,97,279	0.6	₹ 6,55,52,854	0.3
Sikkim	162	₹ 4,60,55,585	0.2	₹ 43,16,80,043	1.9	-₹ 38,56,24,458	-1.7
DVC	765	₹ 20,72,50,133	0.9	₹ 4,60,27,179	0.2	₹ 16,12,22,954	0.7
Arunachal Pradesh	197	₹ 4,60,55,585	0.2	₹ 2,45,29,638	0.1	₹ 2,15,25,947	0.1
Assam	1324	₹ 34,54,16,889	1.5	₹ 50,83,73,104	2.2	-₹ 16,29,56,215	-0.7
Manipur	227	₹ 6,90,83,378	0.3	₹ 4,49,98,952	0.2	₹ 2,40,84,426	0.1
Meghalaya	305	₹ 6,90,83,378	0.3	₹ 4,26,84,223	0.2	₹ 2,63,99,155	0.1
Mizoram	128	₹ 2,30,27,793	0.1	₹ 2,16,29,820	0.1	₹ 13,97,973	0
Nagaland	154	₹ 4,60,55,585	0.2	₹ 3,13,38,204	0.1	₹ 1,47,17,381	0.1
Tripura	365	₹ 9,21,11,170	0.4	₹ 2,74,60,381	0.1	₹ 6,46,50,789	0.3
Andhra Pradesh	2363	₹ 59,87,22,607	2.6	₹ 1,07,59,93,180	4.7	-₹ 47,72,70,573	-2.1
Telangana	4239	₹ 1,08,23,06,251	4.7	₹ 95,26,29,232	4.1	₹ 12,96,77,019	0.6
Tamil Nadu	8460	₹ 2,16,46,12,502	9.4	₹ 1,06,52,59,412	4.6	₹ 1,09,93,53,090	4.8
Kerala	2741	₹ 69,08,33,777	3	₹ 45,94,78,507	2	₹ 23,13,55,270	1
Karnataka	5704	₹ 1,45,07,50,932	6.3	₹ 1,85,87,70,771	8.1	-₹ 40,80,19,839	-1.8
Pondicherry	481	₹ 11,51,38,963	0.5	₹ 2,43,30,119	0.1	₹ 9,08,08,844	0.4

4.4.2 It can be seen that States marked as Red may prefer uniform rate over PoC mechanism and the States in green may prefer PoC mechanism since they benefit by keeping the sensitivity to distance, direction.

4.4.3 It can be seen that with the overall Yearly transmission charge remaining constant, it is the share of allocation among different states which changes in different mechanisms. A decrease in share of one State will surely increase share of another state if the charges are to be recovered from same DICs. There is no solution which can make all States pay less which few states are demanding.

4.4.4 Mr. Vijay Menghani, CEA has submitted that the issue of transmission pricing is too complex and it is not the methodology but events that happened while implementation of POC mechanism, which are making it complex and creating lot of misunderstanding. Two important reasons are actual demand during 12th Plan falling too short of projected demand as per 18th EPS and relinquishment of LTA by generators for whom nine high capacity transmission corridors were planned and constructed . These two events are causing a step size increase in transmission charges of many states. So there is no quick fix solution for the problem as transmission pricing mechanism is merely a allocation of transmission charges (a pie) among all utilities . So suggesting a change in methodology would merely transfer the “regret” from one user to another so whatever solution is to be proposed it must be fair and transparent .

4.5 Is PoC rate variation desirable or undesirable?

(a) An issue was raised that PoC rates should be stable and shouldnot vary much and variation in rates was termed as "price instability".

(b) The PJM report states as follows on stability of rates

"Changes Over Time
As individual loads and generators change their total consumption and generation from year to year, the costallocation method can change the relative shares of cost accordingly. For example, if one load reduces itsconsumption systematically from one year to the next, its share of costs allocated to it will be reduced relativeto other loads. Conversely, if a load increases its consumption by relatively more than other loads, it will be allocated a higher fraction of transmission costs. Allocation of costs over megawatt-hours through marginal lossor congestion surplus accounts for changing system conditions, usage patterns, and underlying fuel prices as they occur.

Stability of Rates
As long as the transmission costs to be recovered and the consumption and generation of the load do not change much over time, rates associated with a megawatt-hour allocation will be stable. However, with added costs of new infrastructure going into service, transmission rates will not remain stable going forward. For costs being recovered through the marginal loss or congestion surplus, these implicit rates for cost recovery are quite unstable and vary with changing system conditions and underlying fuel prices."

(c) In Indian scenario both the quarterly transmission charges are increasing and ISTS drawal of entities are varying from quarter to quarter.The slab rate for an entity is dependent on its ISTS drawal, total monthly transmission charges in that quarter and ISTS drawal of other entities. It is specifically noted that monthly transmission charges vary every quarter. This is in line with the objective of National Electricity policy and National tariff policy where the entities pay as per their usage of ISTS.

(d) Mr Pradeep Jindal, CEA stated that if there is large variation in PoC rates for a state, from Q1 -Q4, then following should be taken into account:

i. This variation could be a natural outcome of true simulation of the system/grid behavior in different Qtrs. If it is so, then we must not worry about the variations and unnecessarily try to average out using external/artificial methods like fairness/min-max etc.

ii. Do/can we apply these fairness things for controlling flow on lines ? If not, then why apply such methods to twist a natural outcome of a fair simulation. This fairness, then would be contradicting to tariff policy provisions of distance/direction/quantum etc.

iii. A variation of upto x5 is not a volatility, as this then reflects change of flow pattern on lines during various seasons in our vastly spread out grid with diverse generation mix.

(e) The variation in PoC rate (Rs/MW/month) of quarters Q1, Q2, Q3 and Q4 for the year 2016-17 has been compared with variation in their ISTS drawl below.

(f) It can be seen that rates are varying as per varying ISTS drawal of States.

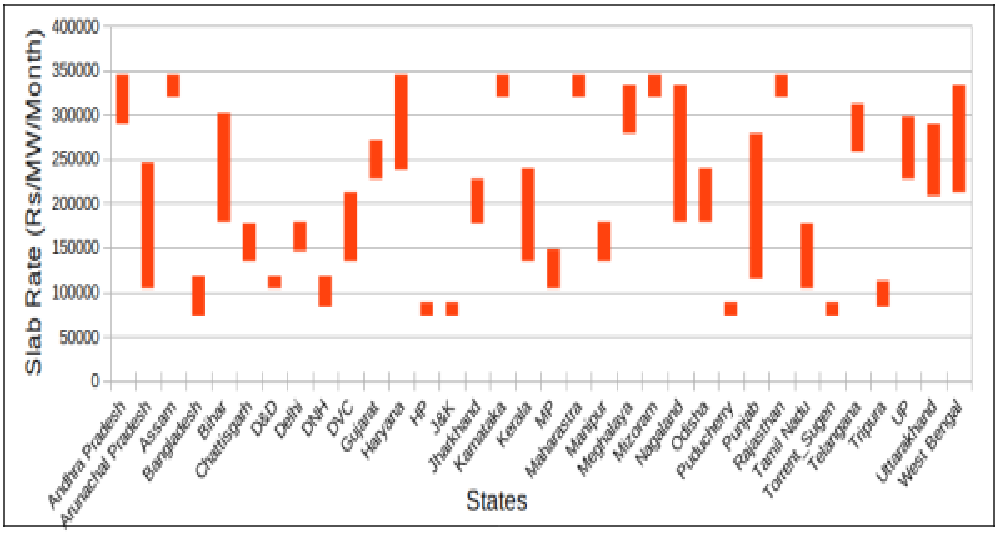


Figure 1: PoC tariffs (Rs/MW/month) using existing CERC mechanism in a year 2016-17.

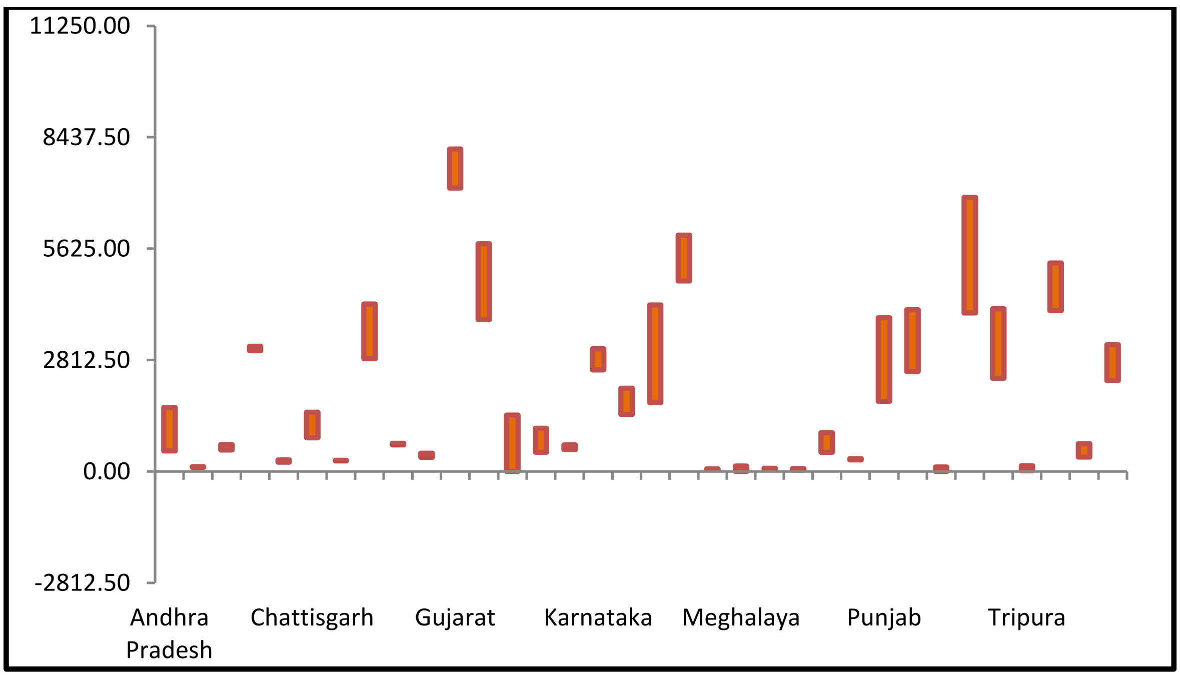


Figure -2: ISTS Drawal (MW) variation in a year 2016-17

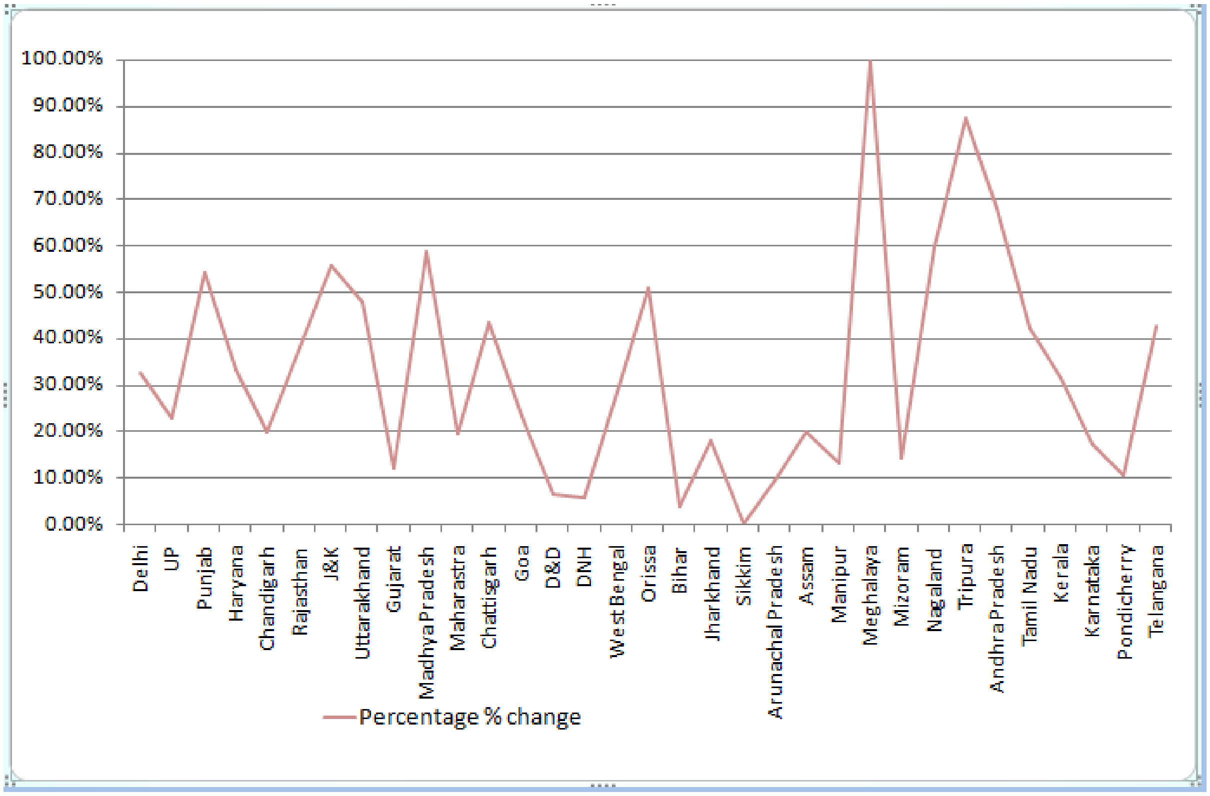


Figure -3: Percentage variation of ISTS Drawal (MW) between minimum and maximum over four quarters of year 2016-17

(e) A related question arises as to whether it is important to have stability of rates or stability of actual tariff implication. Further if a State uses ISTS more during a particular quarter and less during another quarter, the tariff share for that State cannot remain constant with current Policy framework.

(f) The same is explained through an example below:

J&K State ISTS drawl in Q2 2016-17 (summer) is 482 MW and ISTS drawl in Q4 2016-17 (winter) is 1089 MW and Punjab state ISTS drawl in Q2 2016-17 (summer) is 3883 MW and ISTS drawl in Q4 2016-17 (winter) is 2604 MW which is an increase of approx. 55% and 33% respectively. So POC rate of J&K charges are higher in winter season and POC rate of Punjab are higher in summer season.

Hence the variation in rates itself explains the adherence to tariff policy. Hence the rates are bound to vary if monthly transmission charges are varying and the fact that ISTS drawal of all States are varying.

4.6 Analysis with respect to increase of transmission charges

4.6.1 The States have raised grievance that their transmission charges have increased. Hence it is very important to ascertain the reasons for increase in transmission charges over the last 5 years for all the States.

4.6.2 The mainreason for increase in transmission charges for all States is increase in overall ISTS lines. The monthly transmission charge has increased from ~Rs. 700 Crore in 2011 to Rs. 2500 Crore in Year 2017.

4.6.3 During 3rd meeting of the taskforce, representative of CTU submitted an analysis for reason of PoC rates as follows:

Table 7: Analysis of PoC charges, LTA/MTOA and STOA charges

Month	LTA + MTOA + GoI allocation (MW)	Monthly Tr. Charges (Rs. Crs.)	Approx. Rs. Lakhs/MW	STOA Average of 3 Months (Rs. Crs)
Jan 2015	**62991**	**1485**	**2.35**	**179.3**
May 2017	**83660**	**2390**	**2.85**	**318**

(i) During a period of 28 months i.e Jan 2015 to May 2017, LTA quantum increased by 33% whereas Monthly transmission charges increased by 61% due to which rate (Rs./MW) increased by 21%. If LTA would have increased by 18000MW, the monthly transmission charges would have remained same i.e. Rs. 2.35 lakhs/MW.

(ii) During this period of 28 months, the avg. STOA credit has increased by Rs.139Crs which corresponds to about 6000MW of LTA Quantum @ Rs. 2,05,000/- (median slab rate for May'2017) + Rs. 27764/- (Reliability Charges for May'2017). If we assume that STOA is used for 1/3 time of the day, the STOA credit is equivalent to 18000MW of LTA.

(iii) CTU representative stated that large number of LTAs has been relinquished.The timing of relinquishment notably is when CTU seeks opening of LC when the transmission system associated with LTA is close to commissioning.Generally it is seen that excepting for the firmed up PPA, entire target region LTA is relinquished in almost all the corridors.

(iv) The status as in 2017 is as follows:

Table 8: Status of relinquishment on HCPTC

Sl. No.	HCPTC Corridor	Envisaged Capacity (MW)	Effective LTA Remaining on the Corridor (MW)	% Relinquished / Abandoned / In-abeyance
1	I	6080	1263	79.2

Sl. No.	HCPTC Corridor	Envisaged Capacity (MW)	Effective LTA Remaining on the Corridor (MW)	% Relinquished / Abandoned / In-abeyance
2	II	3510	200	94.3
3	III	2162	2162	0.0
4	IV	3760.15	729.3	80.6
5	V	16282	9724	40.3
6	VI	3436	2380	30.7
7	VII	2000	558	72.1
8	VIII	1240.8	0	100.0
9	XI	2137	540	74.7
	Total	**40607.95**	**17556.3**	**56.8**

Due to above relinquishments, the burden of ISTS falls on existing customers of ISTS.

4.6.4 POSOCO has also submitted the factors affecting Transmission Charges as follows:

(i) Commissioning of new transmission assets including HVDCs: With the commissioning of new transmission lines, especially at 765 kV and 400 kV voltage levels, transmission charges have increased from ₹ 7 Billion per month in 2011 to ₹ 26 Billion in 2018. The monthly transmission charges for ±800kV HVDC BNC-Agra (6000 MW) and ±800kV HVDC Champa – Kurukshetra (1500 MW) are ₹ 126 Crores and₹ 84 Crores respectively which is 8% of the total transmission charges.

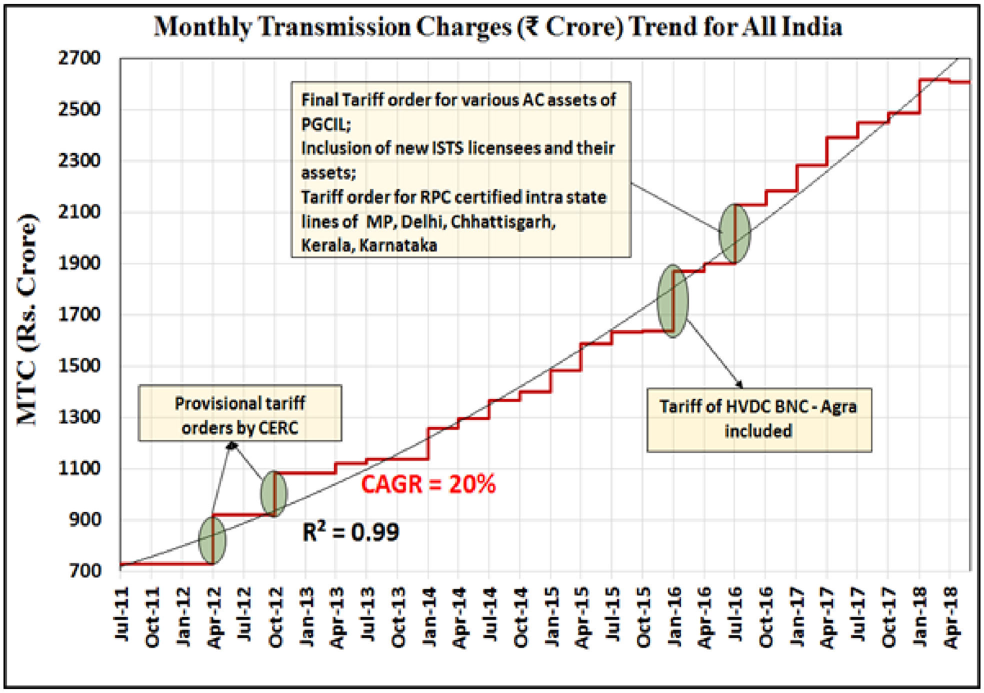


Figure 4: Monthly Transmission Charges Trend of All India

(ii) Long Term Access (LTA) vis-a-vis Monthly Transmission Charges (MTC): As per the present mechanism, transmission charges are shared by various entities on the basis of LTA quantum. During the past seven years, the transmission charges have increased by 260 % whereas the total LTA quantum increased by around 100 %. High capacity corridors were planned considering the future requirements but a large quantum of LTAs could not be operationalized which led to a considerable increase in average transmission rate.

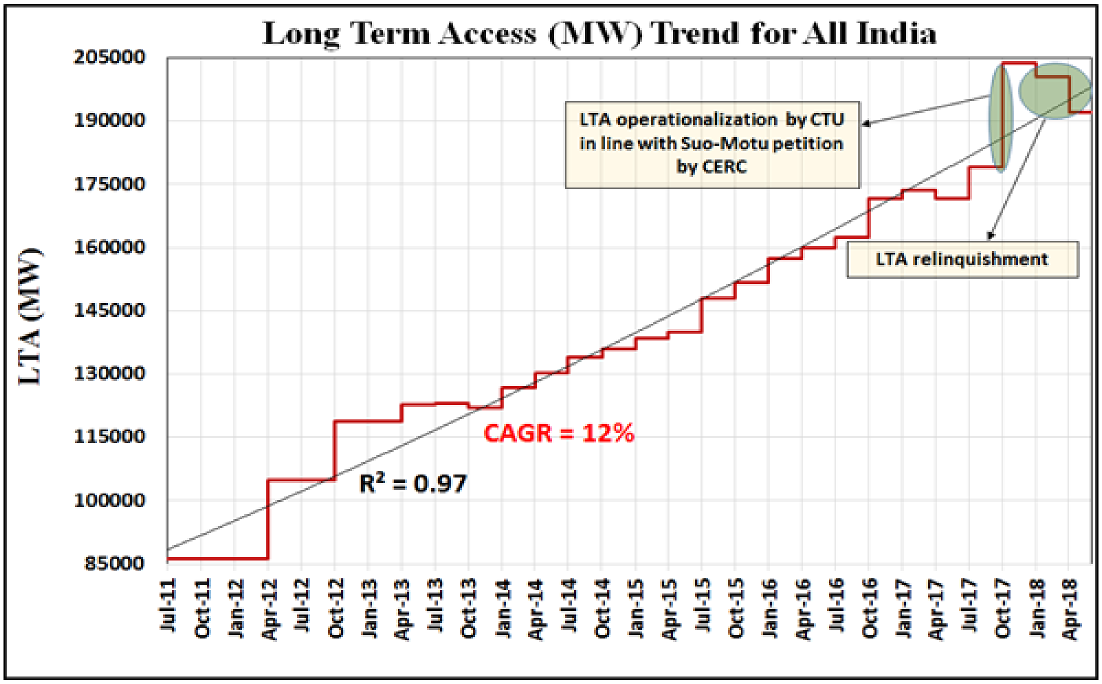


Figure 5: Long Term Access Trend for All India

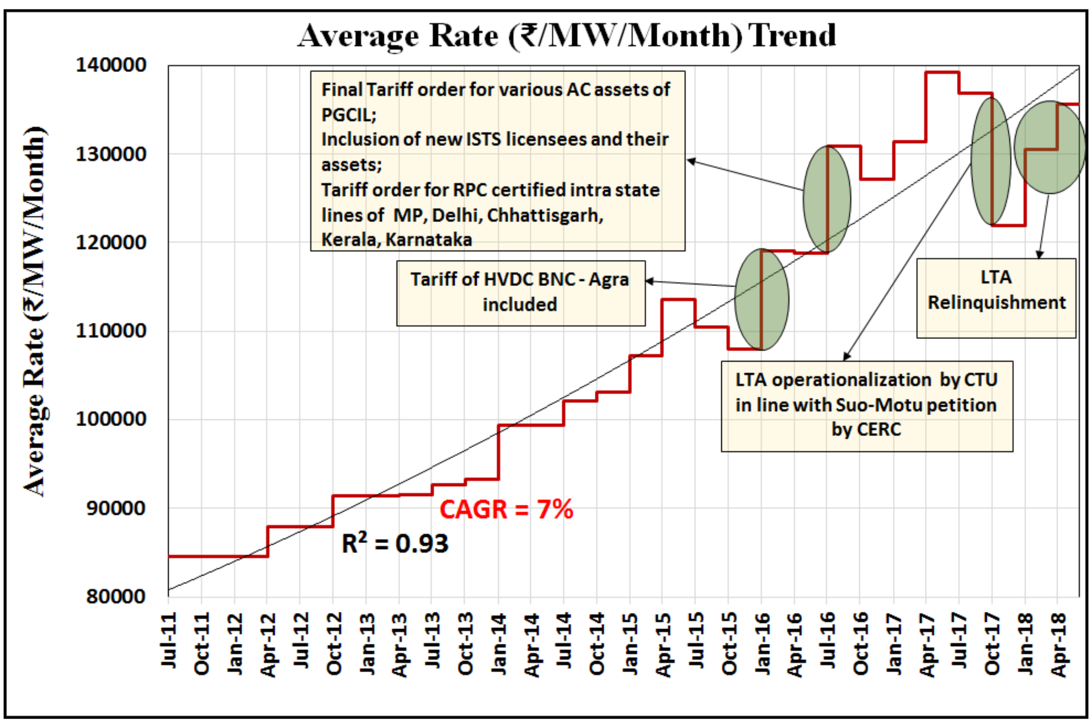


Figure 6: Average Rate Trend for All India

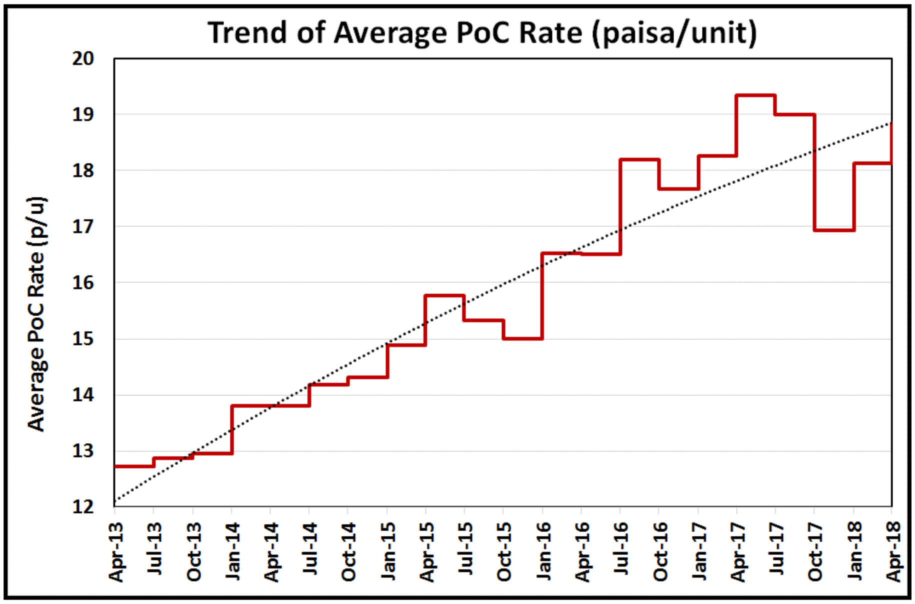


Figure 7: Trend of Average PoC Rate

(iii) Length of inter-state transmission lines: The journey of PoC was started in 2011 and since then, there has been a significant increase in the length of ISTS lines, especially at 765 kV and 400 kV level. It shows an unprecedented growth of transmission as it is nation building exercise which is going on. A table showing the increase in length of transmission lines over the years is given below:

Table 9: Length of different conductor types

Length (circuit kilometeres)								
Conductor Type	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
400 kV D/C Twin Moose	49,270	50,678	54,326	56,936	59,411	60,122	61,550	63,929
400 kV D/C Quad Moose	7,402	9,799	10,432	11,621	14,339	16,296	17,531	19,953

Length (circuit kilometeres)								
Conductor Type	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
765 kV D/C				1,397	7,376	9,687	12,017	14,350
765 kV S/C	703	2,543	5,160	8,110	11,149	13,790	14,263	14,263

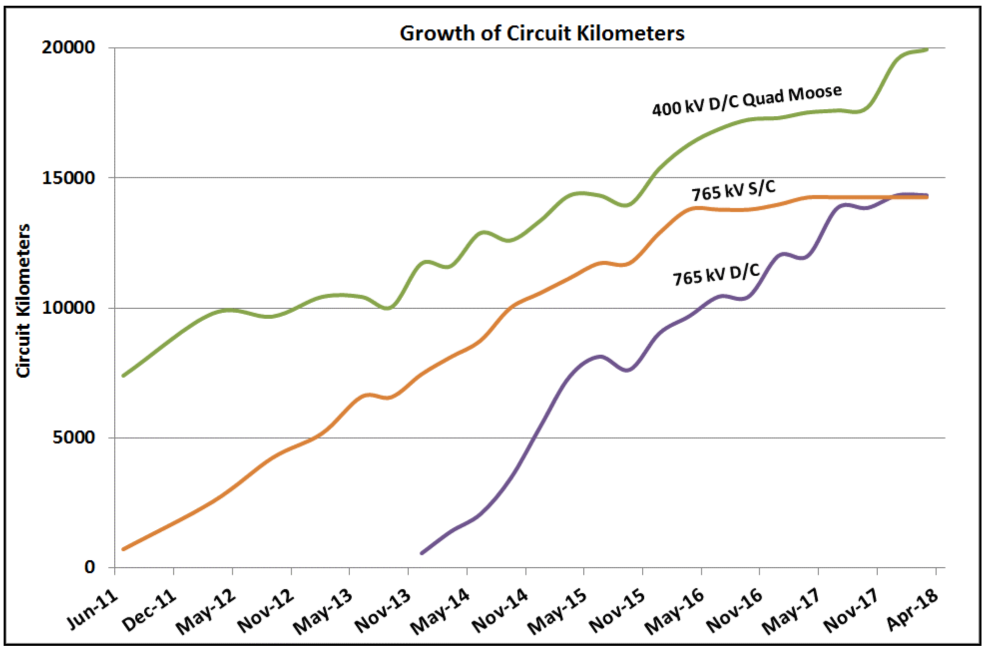


Figure 8: Growth of Circuit Kilometers

(iv)Indicative Cost Level: Indicative cost level of different conductor configuration provided by CTU is used as a primary input for computation of PoC Charges. The cost (Rs. Lakh/Km) provided by CTU has increased over the years.

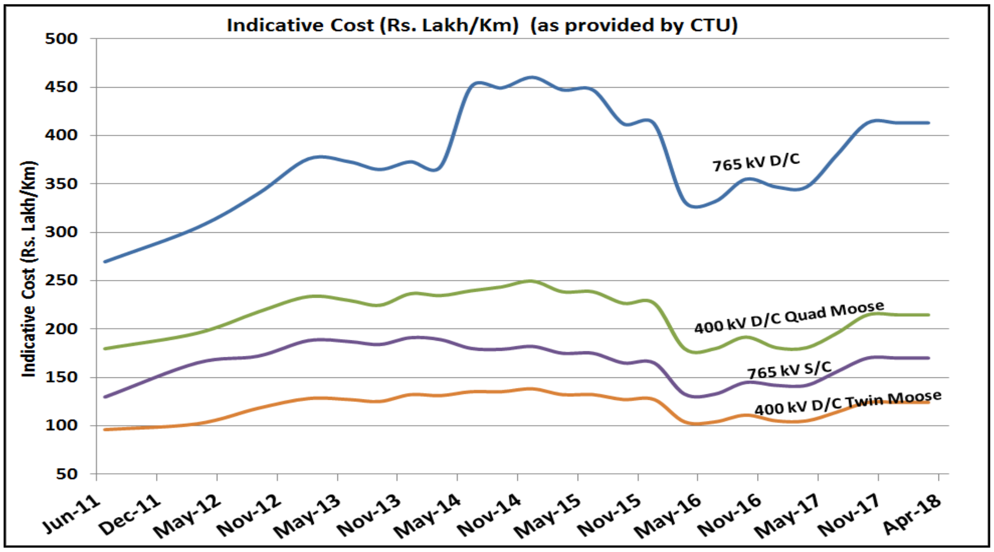


Figure 9: Growth of Indicative Cost

(i) Seasonal variation in demand and generation: Transmission rates are calculated by considering the demand and internal generation of each state. If the internal generation of a state is sufficient to meet its demand, the transmission rate would be comparatively lower than the state which has lesser internal generation and draws power through Inter-State transmission system (ISTS) to meet the demand. The state which is using more of the ISTS network to meet its demand would pay more towards the usage. Transmission charges payable by the utilities keep changing as per seasonal variations.

(ii) Waiver of transmission charges and losses for renewable based power: Inter-state transmission system is a common carrier and the entire Yearly Transmission Charges (YTC) are recovered by the transmission licensees from the Designated Interstate Customers (DICs). The renewable generators (wind, solar, small hydro) would also need transmission infrastructure for evacuation leading to an increase in the YTC. Any waiver of transmission charges for these set of DICs would mean that the other DICs pay for the entire revised YTC leading to increase in their transmission charges.

(iii) Transmission addition in past five years

During the past five years, the country has witnessed a huge investment in the transmission sector and several transmission lines, especially at 765 kV level could be commissioned.

(iv) Long Term Access vis-à-vis All India Peak Demand Met

Over the past three years, power demand in the country has increased.

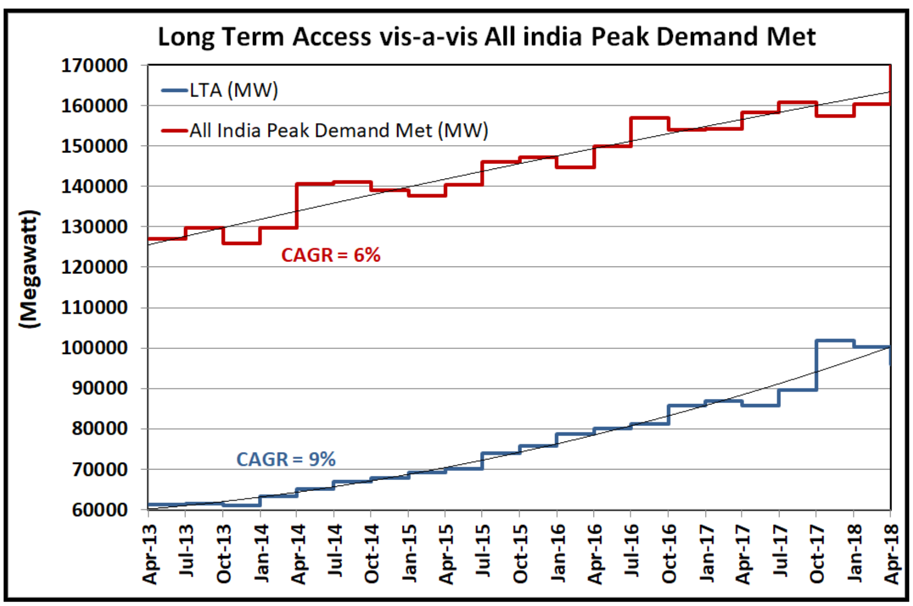


Figure 10: Growth of LTA and All India Peak Demand met

4.6.5 **Analysis of taskforce with respect to increase of transmission charges**

The taskforce observes that transmission system has developed at a rapid pace of 20% CAGR whereas LTAs and demand have not increased. Due to relinquishment of LTA, existing DICs have been burdened with high transmission charges sharing leading to increase in PoC rates for most of the entities. Further the transmission charges per unit for all entities have increased since demand has not increased as projected in 18th EPS and waiver of transmission charges for inter-state transactions have been given. There is an impact of waiver of transmission charges for renewables on increase in per unit charges.

TOR 2: The role of the existing mechanism in improving the power market;

4.7 Requirements of a well-functioningpower market

A well functioning market has characteristics such as Ease of Market Entry and Exit, Absence of Significant Monopoly Power ,Widespread Availability of Information, Absence of Market Externalities,Achievement of Public Interest Objectives. The power market requires buyers, sellers and transmission system for market to function. The taskforce has analysed whether PoC mechanism has helped in improving the power market.

4.8 PoC Mechanism – Role in improvement of Power Market

4.8.1 To analyse the power market we have perused Market monitoring report of CERC . Following is observed from the report:

Table 10: Short term transactions over years

Year	Unconstrained cleared Volume * (BU)	Actual Cleared Volume and hence scheduled (BU)	Volume of electricity that could not be cleared due to congestion (BU)	Volume of electricity that could not be cleared as % to Unconstrained Cleared Volume	Volume of Unconstrained Cleared Volume Year wise (%)	Volume of Short-term Transactions of Electricity (BU)	Total Electricity Generation (BU)
2011-12	17.08	14.83	2.26	13 %	20%	94.51	876.89
2012-13	27.67	23.02	4.65	17 %	62%	98.94	912.06
2013-14	35.62	30.03	5.59	16 %	29%	104.64	967.15
2014-15	31.61	28.46	3.14	10 %	-11%	98.99	1048.67
2015-16	36.36	34.2	2.16	6 %	15%	115.23	1107.82
2016-17	41.6	40.08	1.52	4 %	14%	119.23	1157.94
2017-18	45.86	45.65	0.21	0.5 %	10%	127.62	1202.97

4.8.2 It is observed from above table that despite growth in overall unconstrained volume of electricity CAGR@18%, the % volume of electricity not cleared due to congestion has decreased @42%. This is due to development of transmission system that congestion has reached at negligible level. The increase in volume of total increase in transactions in market indicate that mechanism has led to improvement of market.

Table 11: Variation in short term rates vs short term volume from 2013-14 to 2016-17

Item	2013-14	2016-17	Analysis
Short Term volume	104.64 BU	119.23 BU	↑ 14.59 BU (14%)
Short Market in Monetary Terms	23952 Crs	22124 Crs	↓ 1828 Crs (7.6%)

Item	2013-14	2016-17	Analysis
Weighted Average Cost per unit	Rs/unit	Rs./unit	
PX	2.90	2.50	↓ 0.4 p/unit (13.79%)
Traders	4.29	3.53	↓ 0.76 p/unit (17.72%)
Day Ahead	2.89	2.48	↓ 0.41 p/unit (14.18%)
Term Ahead	3.42	3.09	↓ 0.33 p/unit (9.65%)

(a) It is observed that transaction have increased by 14.59 BU (increase of volume by 14%) with reduction of cost by 1828 Crs (7.6%).

(b) Further weighted cost of electricity has witnessed reduction by 10 – 18 % based on the mode adopted.

(c) This clearly establishes that augmentation of transmission capacity has enabled transmission of power from surplus to deficit area facilitating utilities to procure additional power at lower cost.

4.8.3 The advantages of PoC mechanism with respect to facilitation of power market are discussed in detail in subsequent paragraphs:

4.8.4 Implementation of PoC mechanism for sharing of inter-state transmission charges and losses is a first of a kind exercise in India which has rationalized the transmission charge sharing mechanism and made it more market friendly to encourage competition in the Electricity Sector. The new approach, apart from facilitating transmission as a common carrier and development of transmission infrastructure has also played an important role in the improvement of power market.

4.8.5 **Promotion of Competition:** The mechanism has facilitated integration of electricity markets and enhanced open access and competition by avoiding pancaking of transmission charges. This has further facilitated fair and transparent competition for case-1 competitive bidding. Under the previous methodology, Case1 bid processes were severely distorted because of pancaking, and this also resulted in pit-head/hydro plants not being competitive for interregional bids.

4.8.6 **Promote Renewable Energy Resources:** Solar and wind based generations which are getting commissioned by a partuclar date have been given the advantage of not paying the inter-state transmission charges and inter-state transmission losses for the period of 25 years from the date of commercial operation. This waiver has been granted not through an 'explicit' subsidy infusion into transmission but through an element of cross-subsidizing one set of users by another as the transmission licensees are assured their full return.

4.8.7 **Ex Ante Declaration**: PoC Rates are computed at the beginning of each application period based on the projections. The ex-ante declaration of PoC rates gives certainty of transmission rates and hence market friendly and provides tariff stability.

4.8.8 **Eliminate Pan caking of charges and losses:** Pancaking of charges and losses has been eliminated in the PoC Mechanism. Now each entity has to pay transmission charges of the zone where it is located.

4.8.9 **Accommodates Multiple Transmission Licensee Regime:** Competitive bidding in transmission leads to multiplicity of the transmission licensees which was making the postage stamp method more complex. A one point clearing system for collection and disbursement of transmission charges has been adopted through PoC mechanism.

4.8.10 **Facilitates Development of High Capacity Corridors:** High Capacity Corridors have been planned for evacuation of generation from large generation complexes to load centres. These generation complexes are mostly merchant power stations with unidentified beneficiaries. It would have been extremely difficult to arrive on consensus for sharing of transmission charges and development of transmission system under postage stamp method. Sharing of transmission charges under PoC mechanism does not require identification of beneficiaries at the time of transmission planning since all the charges are being pooled and shared based on the utilisation of the ISTS network by each agent. This has also improved the efficiency of transmission planning.

4.8.11 **Facilitate International Interconnection:** PoC mechanism has facilitated interconnection of Indian Power System with Bangladesh Power System. Bangladesh has been allocated power from different stations of NTPC across the country. In PoC Mechanism, Bangladesh has to pay zonal transmission charges of withdrawal of its zone and nodal transmission charges of generating stations from which power has been allocated to Bangladesh. The mechanism of transmission charges sharing would have been complex under the postage stamp method wherein there were a lot of pools and sub pools.

4.8.12 **Risk Mitigation for Transmission Licensees:** In the postage stamp method, the default in payment by any entity was the risk of the transmission licensee whose customer is thedefaulting entity. PoC mechanism has mitigated thisrisk of transmission payment default for a transmission licensee by forming a larger pool. In case of payment default by any entity, there is a pro rata reduction in pay out to each transmission licensees.

4.8.13 **Contribution to the Society:** Transmission is a common carrier and public service. All India power system network data for studies has been modelled and shared which proved extremely useful for academic institutions, research scholars and other stakeholders.

TOR 3: Deficiency in the existing mechanism if any, and in the light of issues and concerns of various stakeholders.

4.9 Deficiency in the existing mechanism if any, and in the light of issues and concerns of various stakeholders

4.9.1 Approach to handle each of the deficiencies

The taskforce has recommended two options for transmission cost allocation viz (a)modified PoC method and (b)Uniform charges method. Modified PoC method shall have four components of transmission charge viz (a) Point of Connection charge (b) Reliability charge (c) Residual Charge (d) HVDC charge and Uniform charge shall have two components vz Unifrom charge and HVDC charge. All the deficiencies deliberated in subsequent paragraphs shall be handled keeping in view these two approaches i.e Modified PoC or Uniform charges method.

4.9.2 Transparency in calculation of Transmission Charges under PoC Mechanism

(a) Many stakeholders have pointed that in order to increase transparency in calculation of transmission under the existing PoC methodology, the Web Net-use software used for such calculation should be made available to all DICs free of cost. Also, the Implementing Agency should upload data in systematic and user friendly manner on its website, the CTU should share details regarding determination of indicative cost of transmission lines and methodology for deriving average cost from the indicative cost with all DICs. The Stakeholders have also requested the Task Force to device a mechanism so that the details are shared in a transparent manner within a specific timeframe. Some stakeholders have also pointed that every investment proposal in transmission should be made available in the public domain and details should be provided to the intended beneficiaries.

(b) During the 4th meeting of the Task Force, it was decided that the Web NetUse software may be purchased at RPC level for States. Further, during the said meeting, the representative of POSOCO showed the data in respect of load flow analysis uploaded on the website of POSOCO, and representative ofCTU stated that stakeholders should come forward with their apprehension in respect of billing and CTU is ready to extend any support sought by stakeholders.

(c) Analysis and Recommendations of the taskforce

a. The Taskforce recommends that the data pertaining to PoC or Uniform rates is available on the website of Implementing Agency. Following data should be made transparently available on website of Implementing Agency:

   (i) The base case load and generation data nodewise used while calculating allocation of charges or losses.

   (ii) New lines/systems added while billing for a particular month as compared to last month

   (iii) Lines/system which have been taken out in current month billing over last month.

   (iv) The detailed calculation of indicative cost to conclude how the average cost of each line has been derived.

   (v) All the above data should be available in user friendly “Excel” format.

b. In case of any difficulty in accessing the data or formats of the data, respective DIC may approach Implementing Agency . In case the issue remains unresolved, DIC may approach the Commission.

c. Further, an interactive “query” should be designed to give results like (i) Given generator is meeting which loads and in what proportion, (ii) Given load(s) is met by which generators and in what proportion, (iii) Given DIC is using which transmission lines and in what proportion, (iv) Given Transmission is serving which DICs and and in what proportion etc.

4.9.3 Whether PoC is a black box?

(a) POSOCO representative stated during the first meeting of the taskforce that some of the States feel that POC is a black box. All the data pertaining to PoC i.e base case file, allocation of costs-nodewise, lines which an entity is utilising is available transparently on NLDC website. Any entity can get the base case file from NLDC website and carry out simulation itself on the software. The software is available with IIT Mumbai. The taskforce had decided during the stakeholders meeting that software may be purchased by each RPC and provided to States in their region. However it has been reported that there has been no consensus to buy the software. Sharing regulations at regulation 17 provides the information to be published by implementing agency in public domain as follows:

"17.Information to be published by the Implementing Agency

(1) The information to be provided by the Implementing Agency consequent to the computations undertaken shall include:

(a) Approved Basic Network Data and Assumptions, if any;

(b) Zonal and nodal transmission charges for the ensuing Application Period;

(c) Zonal and nodal transmission losses data for the ensuing Application Period;

(d) Schedule of charges payable by each constituent for the ensuing Application

Period;

(e) YTC detail (Information submitted by the transmission licensees covered under these Regulation and computation by Implementing Agency);

(f) Zone wise details of PoC Charges to enable each DIC to see details of transmission lines it is using and whose transmission charges it is sharing;

(g) LTA /MTOA and their commencement schedule."

(b) Further a detailed explanation of all the steps carried out while calculating PoC charges along with examples have been included in Statement of Reasons issued with 3rd amendment of Sharing Regulations.

(c) The suggestions received from stakeholders by the taskforce are itself a demonstration that the mechanism has been well understood by stakeholders and accordingly they have been able to find out and point out as minute things as payment for Jeypore-Gazuaka line by Gridco even when flow in it towards SR. Further the struggle to reduce projected ISTS drawal, HVDC setpoints in Validation Committee meetings is a proof of understanding of the mechanism. For, the entities stating it as a black box, it seems either they have understood the mechanism, however their charges have increased and hence they are stating that they donot understand or they are trying not to understand.

4.9.4 Actual line wise MTC vs. MTC calculated on average cost method

(a) Stakeholders have pointed that under the existing PoC mechanism, average cost of transmission elements is considered while arriving at the PoC slabs. Due to use of this averaging method, same monthly transmission charges per circuit km of line for same type of line needs to be paid by beneficiary even if new line is being erected in other region. In other words, the cost of old transmission system is cross subsidizing the higher cost of the new transmission system being developed due to averaging of system cost whereby the existing DICs are made to share the additional burden of the new transmission system which is not created at their behest whereas the new LTA applicants are benefitting by way of paying reduced charges.

(b) Representative of POSOCO has submitted that transmission charges for each individual line is not available as the tariff for the transmission assets are approved as a package. Moreover, old and new assets provide the same service to the customers. In the scenario of multiple transmission service providers and unavailability of line wise bifurcation of approved tariff, cost apportionment is difficult.

(c) Mr. Vijay Menghani, CEA has submitted that The issue of using Average tariff vs actual tariff in computation was also examined in detail. As line wise tariff was not available and substation tariff was also to be recovered , average tariff of various voltage level lines has been used in computation. This method would not be disadvantageous to anyone, if transmission assets are created in every part of national grid . However analysis of transmission construction of ISTS line during five years revealed that lines were mostly constructed from WR-NR and WR-SR and ER-WR for transfer of power from IPPs. It may be mentioned that before POC, transmission charges were being pooled on regional basis and User used to pay pooled tariff of old and new lines , however as pooling was done regional basis , it was not explicitly visible and impact was not negative as pace of asset growth was not very much different for regional constituents of the grid.

In average tariff system, older depreciated line subsidized tariff of new lines. This results in adverse impact on transmission tariff for utilities for whom no new transmission is being built. The clear implication is visible in North Eastern Region where transmission charges has increased even when their demand or drawl from ISTS has not increased. However it can be mentioned that if actual tariff is used in place of average tariff of line , some unexplainable results in form of different POC for two nearby nodes will be computed based on whether node is connected with old line or new line. This was examined at the initial stage of framing of regulation and was dropped. Wherever similar flow based method are being used, like UK National grid average tariff is used. Similarly in other infrastructure sectors like Railways, no distinction is being made on old or new line while deciding tariff.

So as per analysis, the problem is specific to North Eastern Region as not many lines were constructed in NER .Also the major increase in NER constituents is due to some under utilised asset constructed for Kameng and Subansiri HEP Project. Only Bongaigaon –Baripara 400 kV Quad with 30% FSC is burdening NER states by almost 30% . This issue need to be handled separately.

He has suggested that at present method based average tariff of transmission lines may be continued with modification of incorporating substation cost .

(d) Analysis and Recommendations of the taskforce

(i) The issue of cross subsidizing was raised by stakeholders while issuing Principal Regulations in 2010. Statement of Reasons dated 11.6.2010 issued with CERC Sharing Regulations 2010 notes as follows.

" 3.3.49 Comments: In the determination of transmission pricing, the revenue requirements of transmission assets of the same voltage class are pooled. The addition of new transmission assets will increase the tariff as the old assets have been depreciated. Therefore, the transmission tariff charged to those utilities on the basis of old assets may be affected. (GETCO)

3.3.50 Order / Analysis: Nearly all states require more generation and associated transmission assets. The loss because of having to pay more on an average of old assets gets neutralized to an extent by having to pay less for new lines."

(ii) Further the possible benefits of averaging cost across voltage class can as follows:

1. To make allocation of transmission charge on a node as distance sensitive, equalization of value of all transmission lines whether old or new was required. Otherwise, the charges for specified quantum of flow of power for same distance on new line and old line would be different and results may not reflect distance sensitivity. For example it may happen that a State is drawing power from larger distances i.e from faraway generators. Suppose

the power which reaches the State flows through old lines (which will have less tariff). Similarly another State draws power from relatively nearby generators, but since tariff for new lines is higher will be levied higher charges under the mechanism. Hence the results will not satisfy tariff policy objectives.

2. Equalization of all transmission lines of the same voltage level cannot be termed as discriminatory as the States use both old and new transmission lines and the loss on account of having to pay more on an average of old assets get neutralized for having to pay less for the new assets. However States may raise an issue that they are not utilising new lines and hence should not cross subsidise.
3. In a few cases tariff for transmission lines are not available assetwise i.e line wise and clubbed tariff is being approved. Averaging of the cost helps to handle such cases.

(iii) The Taskforce observes that electricity flows through laws of physics and not through contract path or desired path except for dedicated lines. Hence it is not the drawing entity or injecting entity which decides which line ie. Old line or new line is to be used for its drawal. Hence there shouldnot be difference in tariffs considered for such lines. Non averaging of cost may lead payers of transmission to indulge into such activities so that the power is wheeled to them through old assets which may be a non-optimal solution. The taskforce recommends to continue the averaging of cost across voltage class so that distance, direction and quantum of flow sensitivity is maintained for modified PoC method. In case of Uniform charges method, the issue of averaging doesnot arise since the entire system except HVDC is averaged out.

4.9.5 Variation of rates for a few States

(a) APP vide letter 28.11.2018 has stated as follows:

"We wish to bring to your notice the large/ abrupt variations in the PoC Charges recently published for some of the Zones - especially DNH, D&D, Madhya Pradesh, Odisha, and Bihar, to name a few.

Variation in some of these Zones from Q1FY17 to Q3FY19 are shown in the below table, and the details are enclosed as Annexure:

Increase in POC Charges in Q3 FY19 Compared with Ql FY 17	
State	% Change - POC Charges
Dadra and Nagar Haveli	232%
Daman and Diu	187%
MP	141%
Odisha	76%
Bihar	76%
DVC	51%
Punjab	16%

In the case of Madhya Pradesh, for a 1000 MW transmission contract, the total interstate transmission cost has increased by Rs. 177 Cr (-141%) in Q3FY19 compared to Q1FY17, as shown in the below table:

Particulars	UoM	Ql FY17	Q3 FY19	Change	%
Contracted Capacity	MW	1000	1000		
MP POC (excluding reliability & HVDC charges)	Rs./MW / Month	104089	251244	147155	141%

Annual Impact	Rs. Cr	125	301	177	141%

Such abnormal increase/ variation in PoC charges can be due to various reasons including part-commissioning of new network lines in one Zone leading to under-utilization of network. Such under-utilization of network leads to overcharging the existing consumers for the lines commissioned for "yet to be added" consumers. This leads to excessive burden on the Discoms/end consumers and also the Generators in cases where such charges are nonreimbursable (in few Case-1 PPAs and exchange transactions)."

(b) In particular an issue was raised by DNH where its charges were increased by 103% in Qurater 1 -2019-20 over Q4 (2018-19). The reason for same was analysed by Implementing Agency which stated as follows:

"Due to re-arrangement of the network 400 kV Kala node is now connected with 400 kV Kudus through two circuits and the direct line from 400 kV Boisar (PG) – Kala was removed. Further, 765 kV Padghe (PG) substation along with 765 kV D/C Aurangabad – Padghe also commissioned in March 2018. Considering the electrical distance, the nearest generator from where the power is coming at Kala node is GMR-Raikheda and the transmission lines used are 1. 400 kV GMR-Raikheda – Durg 2.765 kV Durg – Wardha 3.765 kV Wardha – Aurangabad 4. 765 kV Aurangabad – Padghe GIS 5. 400 kV Padghe GIS – Kudus 6. 400 kV Kudus – Kala As mentioned above, 765 kV lines are being utlized for meeting the loads at Khadoli and Kararpada. The transmission charges of 765 kV lines are comparatively higher that 400 kV lines.Therefore, the PoC charges and hence the PoC rate of DNH got increased in 2018-19_Q1 in comparison to 2017- 18_Q4. ".

(c) Analysis of the taskforce with respect to increase of charges for DNH

It is noted that monthly transmission charge (MTC) over Q1FY17 to Q3FY19 increased by 52% (FromRs 1901 Cr. To Rs 2888 Crore). Further as analysed by IA, the additions in transmission system are not shared in equal proportional by all but is shared based on its utilisation. Further addition of new elements changes share of allocation of existing system among DICs also based on revised flow of power. It is also observed that despite Monthly transmission charges increasing quarter by quarter, there has been decrease in charges attributable to DNH during Q2 and Q3 2017-18, Q4-2016-17.

The taskforce observes that issue should get resolved with introduction of Residual charges in case charges for less utilised line is being borne by utilities utilising the line under modified PoC method. Under Uniform charges method, any new additions shall be socialised and hence the impact of such new investment shall be shared by all entities.

4.9.6 Methodology for computation of transmission charges for RE

(a) Some of the stakeholders have pointed out that the cost of transmission system planned and implemented for integration of renewable source of energy should not be loaded on the DICs and the same should be billed as separate bill in the transmission bill. Also cost of such system should not be socialized and should be recovered only from the intended beneficiaries. Some stakeholders have pointed that keeping in view the policy of promotion of renewable energy and large scale renewable energy integration, the effect of such large scale integration of RE & other distributed energy sources need to be quantified & reflected in PoC charge calculations. Further, some stakeholders have pointed that the PoC methodology should be redesigned for equitable allocation of transmission charges for RE.

(b) As per current policy framework, RE Generators are exempted from paying the transmission charges under specified conditions. Stakeholders have sought clarity with respect to impact of such waiver and methodology followed for such waiver.

(c) CTU representative submitted as follows during 3rd meeting of the taskforce:

"

(i) Till date no element under the green energy corridor - I or II (Tirunelveli & Bhuj respectively) has been commissioned. Therefore, these are not been covered in present POC.

(ii) Under the NP Kunta Solar Park (1000 MW)

a. 250 MW has been commissioned and entire power us being scheduled to AP by AP SLDC

b. Phase – I Transmission system (including 400/200 kV substation with transformers and reactors alongwith LILO of Cuddapah – Kolar 400 kV line therein) has been commissioned since July, 2016

c. Approved cost – about Rs. 160 Crs, approved YTC for 2017-18 is Rs. 31.76 Crs

(iii) Additionally LTAs of about 750 MW solar projects embedded in STU network are under operation

(iv) Therefore, as of now there is no significant impact of Waiver of ISTS charges to Solar/Wind projects.

(d) Analysis and Recommendations of the taskforce

a. Keeping in view that other renewable generators connected to ISTS are getting connected to the grid along with system augmentation, the treatment of such waiver needs to be specified explicitly. The treatment may be done in either of two ways:

   (i) The new system built for such renewable be identified separately. Such systems should be scaled up on existing DICs in ratio of allocated charges or LTA/MTOA.

   (ii) Another mechanism can be transmission charges are allocated to generator or drawal node as for conventional generation. The charges corresponding to LTA/MTOA for such renewable generators for which charges are waived off need to be determined. After determination of these charges, the charges pertaining to such renewable to be scaled up on all DICs i.e socilaised.

b. The taskforce concludes that even after waiver, the charges towards such waiver are being borne by existing DICs.Any generation addition utilises existing system also in addition to the augmentation due to meshed status of transmission system. However under recommended modified POC method any linkage with LTA+MTOA is not there for the PoC component. The charges are now proposed to be allocated based on peak ISTS drawal / injectionwhich includes drawal from renewable sources.

c. Out of the above two recommended options, Taskforce recommends Option (a) for both modified Poc or uniform charges method, where **A**ugmentation done for renewable projects (systems specifically created considering renewable generation) should be separately listed. The MTC for such system should be allocated to all entities in the ratio of their contracted capacity clearly making available the cost implications to all entities.

4.9.7 Difference between Long term Access and Peak ISTS Drawl.

(a) Few stakeholders have stated that liability of State should be as per its peak drawl. Hence for cases where LTA is less than peak ISTS drawal its LTA should be enhanced upto its ISTS drawal. Further it has been suggested that no credit pertaining to MTOA/STOA transactions should be passed on to customers who are not having LTA commensurate with their Peak Demands.

(b) The Taskforce observes that currently an entity is actually billed PoC charges based on its ISTS drawal/ injection considered in base case except for HVDC and reliability charges which are based on LTA+MTOA. Hence for entities with ISTS drawal higher than LTA are levied charges as per ISTS drawal in the base case. For the entities who have projected less ISTS drawal pays less under PoC. The taskforce has proposed to do away with LTA based payment and has proposed to bill as per actual ISTS drawal both in Modified PoC or Uniform charges method except for residual component in Modified PoC. Hence the issue gets resolved. Any deviation beyond ISTS drawal considered in base case has also been captured by billing as per actual ISTS drawal in a particular block.

4.9.8 Whether Slabs should continue in POC

(a) Few states have recommended that earlier system of 3 slabs should continue. Few states have stated that there should be no slabs.

(b) Representative of CTU stated during meetings of taskforce that we curb distance, direction sensitivity by making slabs. He also stated that making zones after determination of nodal charges also curbs sensitivity of nodal charges. For eg. Charges for eastern UP and Western UP are pooled together in one zone.

(c) CERC vide draft third amendment to Sharing regulations proposed to do away with slabs. However while finalising third amendment 9 slabs were notified with a mandate to review the same after two years.

(d) Mr. Pradeep Jindal, CEA stated that there should be same quantum (e.g. approved quantum) which should be used for – (a) in calculation of nodal charges through POC model/software, (b) arriving at POC rate (Rs/MW/month), (c) billing LTA and MTOA transmission charges, (d) the reference for offsetting for STOA charges, and (e) the reference for deviation beyond 20%.

(e) Analysis and Recommendations of the taskforce

(i) The transmission charges computed is based on the peak demand met by a state using ISTS. For the ease of billing this cost is recovered against the Long term and medium term applicants of the state. For arriving the cost slab rates are identified as PoC Rate = Rs (Transmission charges for meeting its peak demand)/(LTA+MTOA).

(ii) The bill is raised = PoC Rate * LTA+MTOA = Transmission charges for meeting its peak demand.

(iii) Slab rates are identified from PoC Rates (Rs/MW) in Again (Rs/MW) by clubbing.

(iv) In case a state is in between 2nd to 8th Slab the maximum difference between its actual PoC Rate and slab rate PoC Rate may not be more than 1/8th of Standard Deviation.

(v) The effect of Slabbing is predominately seen in the states who are either in Highest Slab or in the lowest slab.

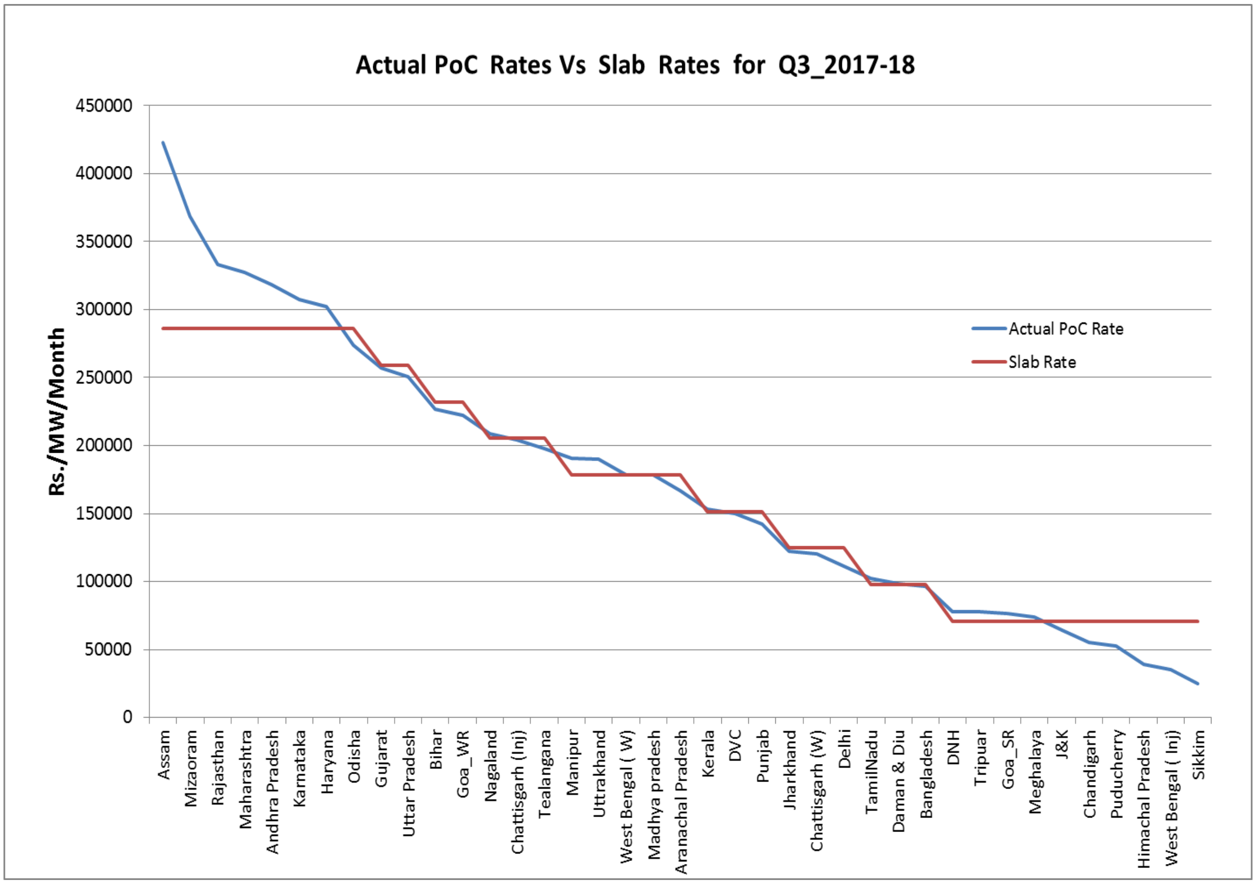


Figure 11: Actual PoC rates vs slab rates for Q3 2017-18

(vi) Slabbing may help to ensure a specified gap between minimum slab rates and highest slab rates which is currently equal to twice sigma i.e slabs vary from mean +sigma to mean-sigma. This ensures compliance to tariff policy which requires gap between minimum and maximum to be such that it doesnot inhibit planned development of transmission sytem . Tariff Policy, 2016 mandates following:

Clause7.1. (3) "………The spread between minimum and maximum transmission rates should be such as not to inhibit planned development/augmentation of the transmission system but should discourage non-optimal transmission investment."

(vii) It is suggested that PoC rate should be calculated by dividing the charges allocated to a particular entity by its ISTS drawal/ injection considered in base case.

There is no need to put them under slabs since slabs are difficult to justify to entities whose charges increase due to slabbing. This PoC rate should be multiplied by actual ISTS drawal /injection blockwise to calculate the charges for a particular entity.

(viii) The issue of slabbing doesnot arise in Uniform charges methodology.

(ix)With regards to comments of CTU recommending nodal charges in place of zonal, it is clarified that ISTS drawal for a State is considered as net of all nodes currently. The Access is also obtained by an entity based on the zone and deviations are also calculated w.r.t such zone. Hence need of nodal charges doesnot arise as of now.

4.9.9 PoC charges based on Actual usage of Transmission System and treatment ofdeviation in ISTS drawl from projected drawl

(a) Few stakeholders have suggested that PoC charges should be calculated considering actual usage of transmission system. Currently the methodology followed for determination of PoC rates is based on projected peak demand/generation for the quarter. It is observed that actual usage of transmission system by stakeholders at any point of time depends on their demand / internal generation which shall be different for every time block. Determination of PoC charges for every block would require actual demand data at each node and actual generation data at each node in each block. It would also require network to be simulated for each block of time w.r.t availability of transmission system.

(b) While determining methodology of "actual",following options can be considered:

a. Actual peak of same quarter of last year to be considered

b. True up is done subsequently.

c. Deviation charges to capture actual ISTS drawal

(c) We have compared the maximum ISTS withdrawal that occurred in actual scenario vis-a-vis projected data considered for PoC computation for one year (October 2017 to September 2018) The projected ISTS drawal is on normalized data since the base case is prepared with normalized values of demand and generation .

Table 12: Difference between Actual and Projected ISTS drawal for Q2-2017-18 to Q2 2018-19

DICs	Q2 2017-18	Q3 2017-18	Q4 2017-18	Q1 2018 -19	Q2 2018-19
	Actual-Projected (MW)	Actual-Projected (MW)	Actual-Projected (MW)	Actual-Projected (MW)	Actual-Projected (MW)
Maharashtra	2974	3929	2123	2903	4552
Tamilnadu	2952	2935	2901	3719	4450
Rajasthan	3621	3676	3683	2893	3185
Haryana	962	1046	1159	2277	2955
Telangana	2887	2459	1802	1237	2350
Karnataka	1875	1250	1816	2268	2049
UP	3605	1397	396	1780	1943
J&K	1282	1143	993	1381	1692
Punjab	804	1590	860	2280	1562
Odisha	1502	1527	1520	1430	1392
Bihar	746	686	633	623	1165
Andhra Pradesh	923	2375	1127	1197	1122
Uttarakhand	808	1055	910	653	1110
Delhi	652	577	770	615	1092
Himachal Pradesh	1085	770	638	1058	915
Assam	752	715	542	705	722
Madhya Pradesh	2874	3114	2701	1830	554
Kerala	825	414	565	452	540
Sikkim	309	300	345	397	313
Tripura	240	254	214	181	218

DICs	Q2 2017-18	Q3 2017-18	Q4 2017-18	Q1 2018 -19	Q2 2018-19
	Actual-Projected (MW)	Actual-Projected (MW)	Actual-Projected (MW)	Actual-Projected (MW)	Actual-Projected (MW)
Jharkhand	265	94	268	376	156
Meghalaya	137	237	101	225	142
Arunachal Pradesh	16	26	29	41	125
Manipur	121	123	130	108	123
Chandigarh	70	64	59	138	108
DNH	101	77	97	107	96
Nagaland	110	94	80	90	94
Goa	97	102	79	566	81
Pondicherry	45	48	56	37	77
D&D	55	56	41	24	32
Mizoram	12	21	18	15	9
Gujarat	-3072	-1113	750	2309	-244
Chhattisgarh	1149	857	656	485	-1300
West Bengal	1541	1361	1193	1057	-2869

(d) It is observed that there is a gap between Actual ISTS drawal vis a vis projected ISTS drawal. For states like Himachal, Sikkim and Meghalaya, it is also observed from the data set that projected ISTS drawal was negative(i.e ISTS injection was projected), however the states also draws power from ISTS in certain blocks and hence ISTS drawl is positive.

(e) States are required toprovide the data of demand and internal generation (Generation scheduled by SLDC) of their State every quarter for the purpose of load flow studies to calculate PoC charges. The difference of demand and internal generation is the ISTS drawl. The projected ISTS drawal is based on peak demand and peak generation. However during real time operation, ISTS drawl is more than the projected ISTS drawal in certain blocks and less than the projected drawal in certain blocks. Since PoC charges are levied based on projected ISTS drawal in base drawal as projected Ex-ante, in case ISTS drawal is more than projected ISTS drawal, additional transmission charges should be levied. The charges can be levied through Regional transmission deviation account (RTDA) prepared by RPCs. The deviations may be billed @ PoC rate till 20% of deviation and with additional charge of 25% beyond deviation of 20%.

(f) The taskforce has suggested modified PoC method based on actual peak scenario for last month for billing in subsequent month i.e bills for actual scenario in January shall be raised in March, bills for February in May and so on. With the modified PoC the billing is proposed to be done on actual ISTS drawal/injection and hence issue gets resolved.

(g) With Uniform charges method also charges shall be levied based on actual ISTS drawal/injection and hence gap between projection and actual doesnot arise.

4.9.10 PoC charges on a State due to its embedded Customers/consumers.

(a) We observe that currently RTDA is based on scheduled transactions i.e LTA+MTOA+STOA minus Actual ISTS drawal. We observe that a State discom may take LTA+MTOA for its ISTS drawal requirement. Further it may take STOA additionally. There are many intra-state entities which may take STOA. While peak demand of a state is calculated, effect of all consumers (including captive consumers) within the State is also taken up in base case. However since such embedded consumers may not have LTA to ISTS, the charges attributable to such loads are levied on the State discom having LTA+MTOA. Although it can be argued that such embedded consumers pay under STOA which is reimbursed back to all DICs of India. Through this arrangement a particular State is being levied charges for its embedded consumers whereas it is not reiumbursed back the full charges. To overcome such an issue , it is suggested that charges collected from embedded entities towards STOA transactions should be reimbursed back to concerned state and not to all the DICs. It may happen that a State who had not considered demand of such embedded consumer while proving PoC data also gets back the STOA charges and some may find it unfair. However it is clarified that whenever such captive consumer will draw from ISTS it will go into RTDA of state and state will be levied charges for the same.

(b) It is also suggested that since ISTS charges are fully recovered under first bill i.e from LTA and MTOA customers, for a State, no charges may be levied under STOA from embedded customers. The state should determine as to the charges to be levied on such embedded customers due to their demand from ISTS. Ideally the charges attributable to such embedded customers should correspond to ISTS drawal due to such embedded cutomers. The state may implement mechanism similar to that available for ISTS i.e PoC based mechanism or Uniform charges based mechanism for intra-state entities.

(c) Further few stakeholders have pointed out that for a generating company, deviations upto 20% are borne by their identified beneficiaries. They have suggested that such deviations should be borne by injecting utility itself. We agree with the suggestion that no Charges for deviation should be borne by drawing utility on behalf of injecting utility.

(d) For States which project to inject into ISTS but actually draws from ISTS, will be levied deviation charges for any quantum of power drawn from ISTS. Starting from 0 MW. For such cases deviation charges may become very high.

4.9.11 Treatment of lines with cumulative Marginal participation factor less than a significant value

(a) GRIDCO brought to the notice of Taskforce that charges for Jeypore-Gazuaka line connected to back to back HVDC is loaded on Odisha when the flow is from Eastern region to Southern region. It was analysed and found that this is due to very low marginal participation which may be appearing due to voltage difference. Ideally for such line connected with back to back HVDC, marginal participation should have been zero considering HVDC set point remains same. Marginal participation for a line will be a matrix of value with one value for each load. The sum of all the positive value shows the usage of a line by different nodes.

(b) Mr. Vijay Menghani, CEA has stated that after lot of debate and discussion , for distributed slack bus selection, average participation method was chosen so that the participating generation for a 1 MW change in load at drawal would be nearby generator. However at present a very small participation factors say 0.0001 by a generating station placed far away from load results in utilization of long line. This need to be modulated by limiting the participation factor to say .01 or almost

.001.Similarly marginal participation factor there should be a limit , at present even a very very small marginal participation is also being considered. It may be technically correct but difficult to comprehend and explain.

(c) **Analysis and Recommendations of the taskforce**

It is seen that for a base case of 2017-18 Q1 with around 13,500 lines (including intra-state lines) the cumulative marginal participation varied from 40 to 7^-23 and average being 1.75. On detailed analysis it is seen that for around 2130 lines (including intra-state lines) cumulative marginal participation is less than 0.001. Such small marginal participation is observed in those lines which are connected to zero loads only (Radially) or HVDC station. Hence such participation is seen mainly due to non-linearity of AC load flow study. Hence, it is recommended that lines whose cumulative marginal participation is less than 0.001, then for such lines all the marginal participation would be considered zero under modified PoC mechanism. The issue of marginal participation doesnot arise under Uniform charges method.

4.9.12 DC load flow vs AC load flow

(a) Some stakeholders have suggested that DC load flow may be used in place of AC load flow for PoC calculations. Professor Soman suggested the Linearized AC Power Flow Model stating as follows:

AC Power Flow: Extrapolation of sensitivities do not match to thereal life powerflows

DC Power Flow: Extrapolation of sensitivities is valid.
Linearized Flow: Models voltage variations and reactive power while maintaining linearity.

DC power flow model: The power flow equation across a series impedance x_{ij} is given by

$$P_{ij} = \frac{V_i V_j}{x_{ij}} \sin(\delta_i - \delta_j).$$

With $V_i = V_j = 1.0$ p.u. and assuming small angular deviation, it can be approximated as

$$P_{ij} = \frac{1}{x_{ij}}(\delta_i - \delta_j).$$

Linearized AC power flow model (LAC):

$$P_{lm_{AC}} = V_l^2 g_{lm} - V_l V_m \left[g_{lm}\cos(\delta_{lm}) + b_{lm}\sin(\delta_{lm})\right]$$

a more accurate voltage magnitude model is used viz., $V_i = 1 + \Delta V_i$.

$$P_{lm_{LAC}} = -b_{lm}(\delta_l - \delta_m) + g_{lm}(\Delta V_l - \Delta V_m)$$

(b) Analysis and Recommendations of the taskforce

(i) The classic power flow problem consists of active and reactive power flow and can be formulated using four variables per node – voltage angle, voltage magnitude, active and reactive power injections, variables are interdependent, making the problem non-linear. In order to reduce calculation time, the power flow problem can be simplified in by making the system linear. By considering (1) Voltage angle differences are small, i.e. sin(ɵ) = ɵ and cos(ɵ) = 1 (2) Flat voltage profile : all voltages are put to 1 p.u.(3) Line resistance is negligible i.e. R<<X, thus lossless lines(4) Tap settings are ignored.

(ii) DC power flow is less accurate compared to the full, AC power flow solution. There are several parameters influencing the accuracy of DC power flow. First of all, the voltage profile has to be as flat as possible, meaning that there should be as little voltage deviations as possible. The higher they become, the higher the active power estimation error. A standard deviation, SV, below 0,015 is desirable. Secondly, the X/R ratio should be high enough, otherwise the assumption of negligible resistance is violated. The proposed border value is set at X/R = 4. The influence of linearizing the sine function is small when the voltage angle remains below 30.

(iii) DC load flow study cannot be used for allocating transmission losses to the nodes as it considers R=0.

(iv) The major difference is that in case if 1 MW is changed in system and power flow change in a line is 0.5 MW then for 100 MW change power flow change in line would be 0.5*100 in the case of DC flow but may not be the same of AC flow due to non-linearity.

(v) It is observed that the benefit cited for DC power flow is that linear extrapolation is valid in such flow. However we observe that DC power flow itself is not a valid model considering that actual load flow is on AC system. Hence its linear extrapolation validity doesnot make sense. Internationally DC load flow has been used for cases of >400 kV since it has been concluded that at higher voltages, results of DC and AC load flow merges and DC load flow takes less time to execute than AC load flow.

(vi) Current PoC software takes approx. 10-15 minutes to provide the results. Hence we donot find any need to shift to DC load flow just for saving time. Infact for apportionment of losses in any case AC load flow will be required, which will ultimately cause more time and more complication since the case will run twice once on AC load flow for losses and once on DC load flow.

(vii) No desired results are seen for shifting from AC load flow study to DC load flow study and hence DC load flow study is not recommended under modified PoC mechanism.

(viii) The issue of load flow doesnot arise under Uniform charges method.

4.9.13 Min-max Fair Dispersed Slack Bus Selection

(a) Professor Soman have suggested use of min-max fairness policy instead of Average Participation (AP) rule to compute dispersed or economic slack bus in the Marginal Participation (MP) approach. Min-max fair Point of Connection tariff (PoC tariff) solution is defined as one, in which, a reduction in PoC tariff of an entity (load or generator) can occur only at the expense of another entity, which pays equal or higher PoC tariff. Thus, the min-max fair price vector represents the equilibrium prices; any deviation from it increases regret of equal or higher price bearers. Professor Soman has also pointed out that Implementing Agency is facing a challenge due to presence of loop flows. The AP method breaks down in presence of loop flows. Loop flows occur due to the presence of HVDC lines. To circumvent loop flows, the base case has to be modified by either altering P-Order of HVDC lines or opening of some light loaded lines. If the commission adopts min-max fair economic slack bus selection rule, then such problems in economic slack bus selection due to presence of loops flows will be automatically resolved. Power flow scenario need not be altered.

(b) Prof. Soman suggested the proposed min-max method vide the draft third amendment which was notified on 4.4.2015. The Commission rejected the min-max method stating following vide the associated Statement of Reasons:

> "22.22. We have also carefully examined the concept of Min Max Method explained by IIT Bombay, during the public hearing.
> 22.22.1 The proposed methodology is based on DC Load Flow method. The approach paper for Sharing of Transmission charges published by the Commission in 2009 had also proposed methodology based on DC Load Flow as it has certain advantage like simplicity and fastness in execution but after discussion with stakeholders in various workshops, it was decided to adopt AC Load Flow method. So the issue of DC Load Flow cannot be reopened without giving chance to other stakeholders to respond.
> 22.22.2 The Min Max method suggested by IIT Bombay, though is based on economic theory, yet it is difficult to implement, as it will change sensitivity to distance, direction and usage. This method reduces the differential of transmission rates of DICs, by selecting different set of participatory nodes (dispersed slack buses) for each node with the objective to reduce PoC rates at a particular node as compared to original computation based on average participation method. This may lead to results which are technically unexplainable to stakeholders. In present methodology, the major participatory nodes are nodes which are nearby nodes and same is easily explainable and can be understood. In Min Max method, the participatory node selection is based on iterative process, sometimes it selects dispersed slack bus which is too far or too remote from the withdrawal node /injecting node which is difficult to explain to the practicing engineers. Also min max method works on the nodal basis and is useful when transmission pricing or energy pricing is done on nodal basis (Locational Marginal Pricing). Sharing of transmission charges at present is based on aggregated PoC rates on Zonal basis after computing at nodal basis. Even if PoC rates of few nodes is decreased, it will simultaneously increase PoC rates of other nodes so the effect on overall Zonal charges cannot be predicted.
> 22.22.3 In view of these difficulties, it was decided that min max method although with its intended benefit of reducing diversity of PoC rates cannot be implemented."

(c) Mr. Pradeep Jindal, CEA has stated that there have been attempts in past (by CTU and POSOCO also) to bring the rate as close to Average POC rate as possible. This is totally against tariff policy provisions of distance/direction. The min-max/fairness is also another attempt in this direction.

(d) Analysis and Recommendations of the taskforce

(i) Min-Max methodology was discussed during the introduction of POC mechanism in 2010. Commission had not accepted this methodology. The relevant portion of the SOR of CERC Sharing Regulations, 2010 dated11th June 2010 stated as follow:-

"3.1 Philosophy of the Methodology:
3.1.1 Comments: Professor SA Khaparde, IIT Bombay, Mumbai et. al. questioned the rationale for using the Marginal Participation Method, when PoC transmission charges could be computed by directly using the Average Participation Method – which is being used in the Hybrid Method for selection of slack buses.

3.1.2 Order / Analysis: The Commission has carefully considered this comment. The Commission is aware of the on-going academic debate between the Marginal Participation and the Average Participation Method. Both the methods have theirstrengths and weaknesses. The Average Participation Method is based on proportionate tracing of electricity from generator node to demand node(s) or viceversa. Though the method requires the results of Load Flow Analysis as its input, the mechanism of proportionate tracing does not follow the Laws of Physics (Kirchoff's voltage law)...

Further the Average Participation Method (Tracing Method) produces results with a higher variance in nodal charges. This interestingly has been reported by Professor Khaparde , Dr.Abhyankar and Professor Soman in their paper (Min-Max Fairness Criteria for Transmission Fixed Cost Allocation, IEEE Transactions on Power Systems, Vol. 22, No. 4, November 2007) They state "It is observed that postage stamp and conventional proportionate tracing methods produce skewed results which can lead to debate. The other two methods allocate costs in a more amicable manner by containing them in a narrower band.

In another paper, Optimization Approach to Real Power Tracing: An Application to Transmission Fixed Cost Allocation, IEEE Transactions on Power Systems, Vol.

21, No. 3, August 2006, the Dr. Abhyankar, Professor Khaparde et. al. claim that: “The easy-to-implement postage stamp method tends to favor heavy users at the cost of light users of the transmission system. Under certain circumstances where equitable cost distribution gains more importance over providing price signals, the conventional proportional tracing can come under question by the heavy users, raising some pertinent points about socioeconomic unbalance. This can be particularly observed in developing countries like India. This is not to say that a versatile conventional method of tracing is unable to handle the situation, but one can explore larger solution space to strike the balance of seemingly conflicting requirements. The proposed methodology attempts to trade off and take a balanced and fair view within the framework of tracing algorithms meeting all technical and socioeconomic constraints…”

The above quote illustrates that proportionate tracing solution is one of the many feasible solutions and may not be the most equitable also. Clearly, lower variance in the results of the Hybrid Method indicates a more equitable solution.

In another recent paper M. S. S. Rao, S. A. Soman, P. Chitkara, Rajeev K Gajbhiye, N. Hemachandra, and B. L. Menezes, “Minmax Fair Power Flow Tracing for Transmission System Usage Cost Allocation: A Large System Perspective,” In Press – IEEE Transactions on Power Systems, 2010., a comparison of MP method and AP method on all India network shows higher variance in the nodal charges obtained using the AP method.

Further, simulations conducted by the consultants in the course of this assignment also revealed that the nodal transmission charges in the AP method have a higher variance. As compared to the range of transmission access charges in the Hybrid method (Rs 2.98 – 17.75 lakh / MW), the range in the AP method (Rs. 2.79 – 53.61 lakh / MW) is much higher.

Finally the Commission is convinced that the academic literature does not establish a definitive superiority of any of the two methods – the Marginal participation Method or the Average Participation Method over the other, but Hybrid Method combines the strengths of both the Marginal Participation Method and the Average Participation Method and also produces results which are explainable (based on the network configuration and underlying network flows) and also politically more acceptable.”

(ii) Fallacies of the proposed Min-Max method:The proposed min-max method has following shortcomings :

(a) Economic efficiency: It was stated that allocation rule should provide efficient siting signals and that min-max method will achieve it. The results of the proposed min-max method shows that the results are completely against siting signals. The charges of States like Chattisgarh which are generation rich are high whereas charges for states like Rajasthan are low which loses siting signal. Since ISTS drawal of Rajasthan is high, it requires more ISTS. Hence the proposed method loses economic efficiency.

(b) Fairness: The principle of fairness is that an entity should not get undue advantage over others. But min-max method fails on this criteria also. Firstly min-max method exactly gives advantage to such person who is using more ISTS at the cost of a person who is using less ISTS and allocates same rate to both such entities. Such an allocation is highly unfair which has no basis. It will also be very difficult to justify the reasons of increase of charges to such entity that their charges have increased because it was desired to reduce charges of other entity. This will be completely against Tariff Policy and principles of natural justice.

(c) Transparency: The proposed min-max method is completely opaque as to the allocation of charges since it tries iteratively to search such a slack bus so that the charges of an entity who is heavy user of ISTS is reduced at the cost of an entity which uses less ISTS.

(d) Simplicity: The proposed min-max method is very complex and non-justifiable. The proposed methodology to determine usage of line and scale up the charges for unused portion for each line is again a very complicated and disputable proposition.

(e) Stability: It was argued that the proposed min-max method is stable in terms of rates which have been determined by making everybody's rate same through min-max method. The same has been compared with POC rates which are determined only on usage principle, by dividing charges attributable by LTA (which is contractual ISTS drawal). It is observed that transmission charges attributable to each entity varies over the 4 quarters even in proposed min-max method. A comparative chart of the charges attributable over the 4 quarters is indicated below:

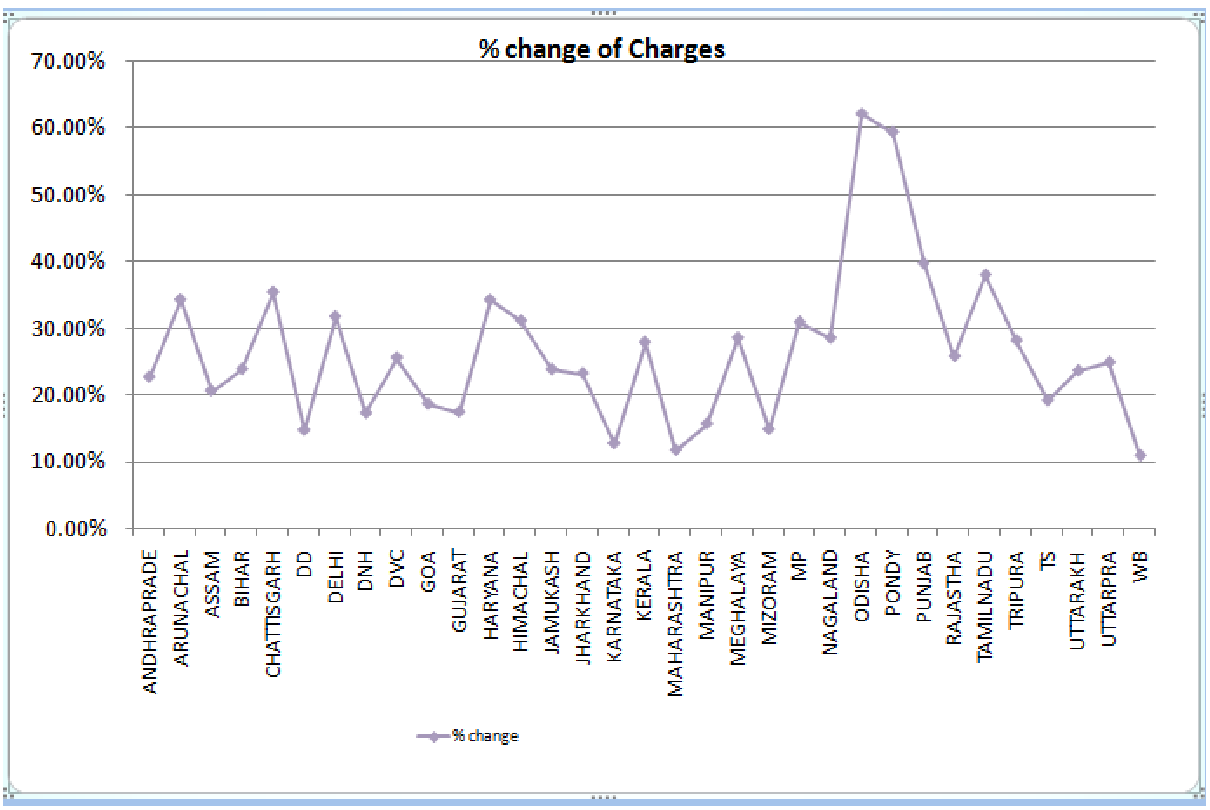


Figure 12: Percentage change between minimum and maximum charges attributable to States over the four quarters under proposed min-max for 2016-17.

(f) It is observed that if principles of Tariff policy are to be adhered to the charges cannot be stable because ISTS drawal of states are varying over quarters and Quarterly transmission charges are increasing @4% every quarter.

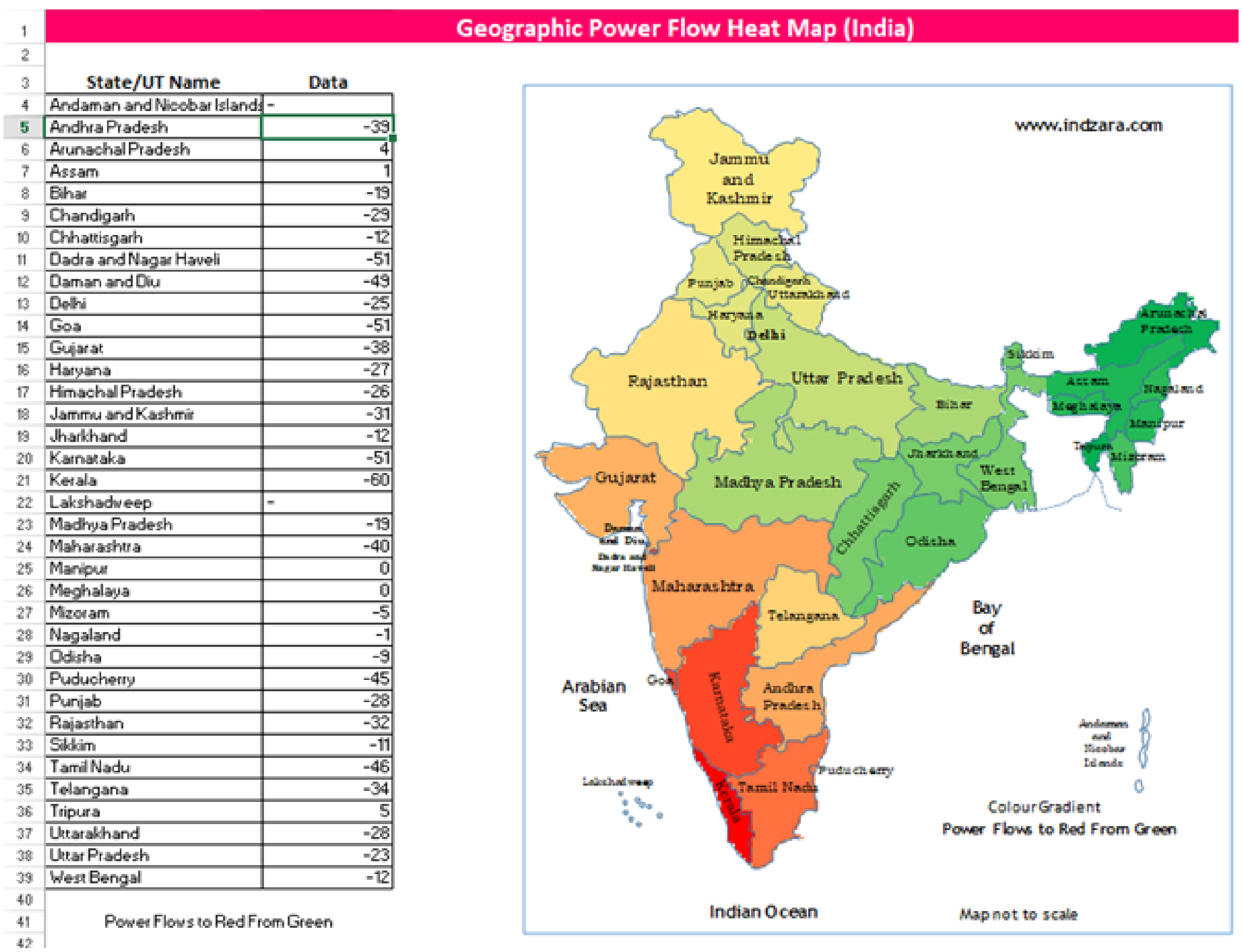
(g) It is noted that proposed min-max methodology is based on cross subsidisation between DICs which cross subsidises high ISTS users at the cost of low ISTS users. Electricity Act 2003 provides that cross subsidies should be progressively reduced. The method proposes to increase the cross subsidy would be against the intent and objective of the Act

(h) Slack bus in transmission pricing mechanism (based on Load flow study) predominates the outcome of the results. There is no unique way for identification of slack bus. The present methodology based on tracing actually captures the distance of various groups of generators from a load point based on the power flow in the base case. This methodology is adopted to capture the distance of generation from load center. Hence Average participation factor helps in computation of transmission charges based on distance. Whereas Max – Min based selection of slack bus is based on minimum regret which is not the intent of tariff policy. Hence the method is not accepted.

4.9.14 **Issue of Loop Flow with Average Participation:**

(a) Prof. Soman had suggested min-max method to solve problems of loop flows. Prof. Som Sekhar, IIT Mumbai had shared Elsevier paper on "Analytical model and algorithm for tracing active power flow based on extended incidence matrix" by Kaigui Xie, Jiaqi Zhou,Wenyuan Li.

(b) However it is observed that as per laws of physics power flows from higher bus angles to lower bus angles.We have observed power flow heat map for India for May 2018 case.


Geographic Power Flow Heat Map (India)

State/UT Name	Data
Andaman and Nicobar Islands	-
Andhra Pradesh	-39
Arunachal Pradesh	4
Assam	1
Bihar	-19
Chandigarh	-29
Chhattisgarh	-12
Dadra and Nagar Haveli	-51
Daman and Diu	-49
Delhi	-25
Goa	-51
Gujarat	-38
Haryana	-27
Himachal Pradesh	-26
Jammu and Kashmir	-31
Jharkhand	-12
Karnataka	-51
Kerala	-60
Lakshadweep	-
Madhya Pradesh	-19
Maharashtra	-40
Manipur	0
Meghalaya	0
Mizoram	-5
Nagaland	-1
Odisha	-9
Puducherry	-45
Punjab	-28
Rajasthan	-32
Sikkim	-11
Tamil Nadu	-46
Telangana	-34
Tripura	5
Uttarakhand	-28
Uttar Pradesh	-23
West Bengal	-12

Power Flows to Red From Green

Figure 13: Power Flow heat Map

(c) In the above map power flows from green colour coded states to red colour coded states and from green to yellow states. It shows loop flow can't take place in pure AC system.

(d) Loop flows primarily takes place under wrong data entry in base case or using HVDC to pump power back. Hence there is a need to check the data entry in base case to avoid loop flows. In case loop flow is occurring due to pump back power from HVDC, such HVDC may be considered on no load such that there is no intentional pumping back of power. If required, HVDC may be kept on no load condition for system security. Such pumping back power unnecessarily takes away Available transfer capability.

4.9.15 **Methodology for calculation of transmission losses**

(a) WebNet software allocates losses for each node based on its usage of all India network. Whereas losses are computed at regional level and only for ISTS element. There is difference in methodology of loss computation at regional level for ISTS element and the methodology of sharing of losses as per Hybrid methodology. It is suggested that a national loss be computed for ISTS element rather than at regional level. As of now the methodology followed is (All generation at regional level- All demand at regional level)/ (All generation at regional level).

(b) The same to be substituted with (All generation at national level- All demand at national level)/ (All generation at national level).

(c) The losses of only those lines to be considered in WebNet whose cost is recovered through WebNet, rather than considering all the lines as the purpose is sharing of losses in ISTS. A state may incur more loss in state system than in ISTS but may be placed in higher slab rate for sharing ISTS losses.

(d) The loss percentage at national level is the loss in MW for evacuation ISTS drawl. Loss allocation for each beneficiary should be such that their percentage loss multiplied by Schedule should be more or less equitable to the loss arrived at National Level, Which means a similar to PoC Charge sharing system should exist for loss sharing.

(e) However this may lead to some complexities. As such it is suggested that matter may be deliberated further with all stakeholders

4.9.16 LTA/MTOA considered in computation of Slab rates and LTA/MTOA considered in RTA

(a) Transmission charges payable by an entity is computed based on the demand met by a state using ISTS under PoC mechanism. These charges are converted to rates(Rs .per MW per month) by dividing the charges allocated to a zone by its LTA+MTOA.

(b) RPC issues the Regional Transmission Account where such PoC rates determined ex-ante by CERC are multiplied by each entity's LTA+MTOA. Sometimes it happens that LTA+MTOA considerd by RPC while issue of account is different than given by CTU while calculation of slab rates by NLDC/CERC. This may be due to reallocation by MoP, human error or if LTA is operationalized in between a quarter which was not known prior to the beginning of the quarter.

(c) This may lead to over recovery by the entity whose PoC rate doesnot capture such LTA+MTOA but actual billing is done based on actual LTA+MTOA. Such errors require recalculation of PoC rates.

(d) It was observed that in case of Kudgi STPP, LTA of ~2300 MW was effective from 1.8.2017. The same was not captured while calculating rates for Q2 2017-18. However such a situation demands two PoC rates, one for the month of July 2017 and one for August and September 2017. Since the quantum of LTA is very high which may have major impact on billing of particular DICs, there is a need to determine 2 rates for the quarter. CTU is advised to clearly indicate LTA operationalization accurately prior to the quarter so that modification of rates at a later date in avoided.

(e) Under the modified PoC or Uniform charges as proposed, with monthly billing on actual ISTS drawal/injection any mismatch of LTA doesnot arise.

4.9.17 **LTA of target region Vs Historical Generation of ISGS**

(a) There could be a case where LTA to target region entity injects too less historically. For example a generator “A” with 3 X 500 MW units injects 200 MW .Suppose “A” has LTA of 1400 MW (which corresponds to all 3 units). Under current mechanism, its injection will be taken as 200 MW and charges will be levied on the basis of 200 MW only whereas it has LTA of 1400 MW. In such a case 200 MW corresponds to si ngle unit only. Ideally its other 2 units are under outage. Hence the charges corresponding to LTA for one unit should be billed under PoC i.e for LTA of 1400/3 = 466 MW should be billed under PoC with injection as 200 MW. Other 2 units , LTA should be billed as average of target region i.e LTA of 932 MW as on average PoC rate of target region.

(b) The above methodology should be followed till generation of technical minimum as per CERC Regulations. i.e if A injects 400 MW and its 2 units are running, average PoC rate for target region is to be considered only for 1 unit. Actual historical operation needs to be ascertained by POSOCO.

(c) In case of modified PoC, the charges are to be billed based on actual injection / drawal. Hence if the generator is injecting corresponding to one unit only, it should be levied charges @All India average rate for LTA towards balance 2 units.

(d) Under Uniform charges method, generators should be billed based on their LTA quantum while determining Uniform rate.

4.9.18 **Separaterates for STOA /MTOA as compared to Long term charges**

(a) POSOCO has submitted that there should be higher Transmission Charges for Short Term in comparison to long term with reasons as follows:

"

(i) Transmission rates in India

Transmission rates are being calculated in line with the CERC, (Sharing of Transmission Charges and Losses) Regulations, 2010. Separate rates are calculated for Long Term and Short Term. However, these rates are almost in the same range. The transmission charges collected through short term open access (STOA) transactions are adjusted1 by CTU in the long term bills raised in the next month.

Transmission charges collected through STOA transactions were Rs. 3822 Crores in financial year 2017-18 against the Yearly Transmission Charges (YTC) of the order of Rs. 30,000 Crores. Details of transmission charges collected through STOA in the financial year 2017-18 is given below:

Table 13: Transmission Charges collected through STOA (Rs. Cr.) from April 2017 to March 2018

Transmission Charges collected through STOA (Rs. Cr.)			
	Bilateral	Collective	Total
Apr-17	167	153	321
May-17	177	158	334
Jun-17	174	159	333
Jul-17	198	147	345
Aug-17	190	160	350
Sep-17	165	171	336
Oct-17	129	163	293
Nov-17	161	137	299
Dec-17	167	118	285
Jan-18	152	130	283
Feb-18	154	124	279
Mar-18	211	154	365
	2047	1775	3822

(ii) Need for different transmission rates for long term and short term

(a)Development of transmission: Transmission is a common carrier and public service. Transmission systems are planned on the basis of Long Term Access (LTA) sought by the generators but not for medium term and short term open access (STOA). Most of the Independent Power Producers (IPPs)/generators have got connectivity to Inter-State Transmission System (ISTS) network without corresponding Long Term Access (LTA). These IPPs are transacting through STOA as there is no obligation to a long term commitment for transmission charges. In the absence of any long term access for such generators, transmission systems do not get built leading to constraints in evacuation. In other cases, it has been observed that IPPs having LTA are relinquishing either part LTA or full LTA as they see certainty in getting STOA, higher prices in power exchanges/STOA-bilateral market and no long term commitment for transmission charges. Under LTA, transmission charges are payable irrespective of power flow while STOA payments are linked to energy volumes.

Hence, in order to build sufficient transmission system for evacuation of all generators in future, it is important that the short term transmission rates are kept higher than the long term transmission rates. This will give a signal to the generators to seek long term access and get the transmission built for future.

(b)Analogies from other sectors: In other sectors such as railways, airlines etc. the prices of a service get higher as we move closer to real time (tatkal, priority tatkal etc.).

(iii) Hence, there is a need to review the rates for STOA transactions so that entities would move towards long term access and transmission gets built.

(iv) Short term rates are calculated by changing the unit of Rs./MW/Month to paise/unit. For example, if the transmission rate is 2,00,000 Rs./MW/Month then to calculate the short term formula would be :

= 2,00,000*100 paise/(30*24*1000)kWH = 27.78 paise/unit

This short term rate is considering 100% load factor. If this load factor is considered as 75% (would be much lower for hydro power plants transacting entirely on STOA) then the short term PoC rate would become (27.78)/0.75 paise unit i.e. 37.04 paise/unit.

(v) Actions taken so far

CERC in the draft fifth amendment to Sharing regulations had proposed to charge Medium Term Open Access (MTOA) and short term open access (STOA) customers at a higher rate. Relevant extracts are quoted below:

"Sub-clause (l) of Regulation 9 of the Principal Regulations shall be substituted as under:

(1) The transmission charges for MTOA customers who are not availing LTA to target region for the capacity under MTOA shall be charged 1.25 times of the LTA POC rates as notified by the Commission from time to time.

(2) The transmission charges for STOA customers who are not availing LTA to target region for the capacity under STOA shall be charged 1.35 times of the normal STOA POC rates as notified by the Commission from time to time.

Provided that the surplus charges collected under above clauses shall be reimbursed back to DICs paying charges under first bill in the next month."

However, the above draft provisions could not be notified due to suggestions of several stakeholders against this stipulation. Since, the transmission system is planned to cater the requirements of LTA customers, transmission charges in respect of power transaction under MTOA and STOA need to be increased."

(b) Mr. Vijay Menghani, CEA has suggested as follows:

(i) At present transmission charges for long term and short term open access are same . Due to this it is reported by PGCIL that as many generator are not having PPA, they are relinquishing LTA and shifting towards Short term . This is beneficial to them as LTA charges are applicable irrespective of usage and payable on MW /Month basis. but short terms are to be paid as per usage on per unit basis. This is creating an arbitrage profit of about 40-50% depending upon sale in short term. This need to be plugged in. They got transmission system built on the basis of "Target Region" LTA and now trying to relinquish their responsibility.

(ii) Similar benefit is derived by few states too as they got built the system for their seasonal requirement and using that for short duration in a year say for 4 months. For balance period it remain underutilized and burden passed on the other DICs.

(iii) One more anomaly is that on STOA no HVDC charges are being imposed while many STOA transactions are happening due to availability of HVDC system, specially on Champa -Kurukshetra HVDC Link.

(iv) It is suggested that tariff of underutilised transmission system is recovered through STOA . At present almost 12% of transmission tariff is recovered through STOA. Out of 2400 Crs MTC about Rs 320 Crs is recovered through STOA. Till the time more long term PPAS are signed, it is proposed that STOA charges are made double so that about 25% transmission charges rae recovered through STOA.This will result in recovery of about 600 crs

(v) The stakeholder need to understand that the assets created under HCPTC corridor scheme form 2012-2016 remain underutilized as expected generation capacity of

23000 MW either did not came or not able to sign PPA . So transmission charges for transmission system constructed for this need to be recovered.

Suggestion : Transmission charges for Short Term transaction may be enhanced to recover tariff of under utilized system .

(c) Analysis and Recommendations of the taskforce

The Taskforce agrees that STOA rates should be higher than LTA rates as proposed by Commission during draft 5th amendment to Connectivity Regulations. However keeping in view proposal of GNA mooted by Commission, in case all entities have GNA, STOA rates may be zero for such entities for transactions upto GNA quantum.

4.9.19 Online telemetry

(a) Stakeholders suggested that CTU / State Utilities shall arrange to provide / facilitate access of online telemetry data in a time bound manner so as to improve the accuracy of the Pricing mechanism.

(b) Analysis and Recommendations of the taskforce

The telemetry status for State level points is covered at TOR 4. Further data from SEM meters for ISTS points are available with POSOCO 15 minute blockwise. Further, the issue of online availability of data through SCADA was raised for Punjab and Haryana to Secretary, CERC. The taskforce observes that communication network of Powergrid is yet to achieve 100% backup as required vide CERC(Communication System for inter-State transmission of electricity) Regulations, 2017. CTU should ensure the telemetry as per CERC Regulations.

4.9.20 **Data input in software**

(a) Stakeholders have pointed out that there is no auto check in both PSSE & Webnet Software for limit for exceeding maximum electrical parameters (more than electrical parameter)- The base case network taken for computation of POC shows that Generation taken in base case network for some of Generating units are more that its maximum normative in fact more than MCR and in some case up to 1.5 times of MCR and this is practically impossible.

(b) Analysis and Recommendations of the taskforce

The Taskforce suggest NLDC to carry out thorough checking of the data input in PoC file to ensure that Pmax is not considered more than MCR of the machine. NLDC may share the file with States and generators to take care of their respective data.

4.9.21 **Reactive power considered in PoC software**

(a) Representative of Maharashtra has pointed out that there is no proper check on Reactive Energy flow in PSSE & Webnet software. For computation of converged basic network, node wise both active & reactive power are required to be provided by each DICs. However base case network taken for computation of POC shows that power factor of almost all nodes of some of state are declared same & that too near unity.

(b) Analysis and Recommendations of the taskforce

(i) We have perused Regulation 16(4) of CERC Sharing regulations which provides as follows:

"(a) MW and MVAR Data for injection or drawal at various nodes or a group of nodes shall be submitted for maximum injection/maximum withdrawal for each application period. Such data shall include the power tied in long term contracts and approved medium term open access agreements."

Hence the MVAR data or the reactive power data was to be provided by DICs. It is not clear if the representative of Maharashtra provided the MVAR data or not. NLDC includes the data as provided by DICs. In case of any discrepancy, the same may be communicated to NLDC for corrections.

(ii) Under Uniform charges method, any load flow is not simulated and hence data for reactive power is not required.

4.9.22 **Transmission Planning**

(a) Stakeholders have stated that every transmission scheme seeking regulatory approval should contain the details regarding its effect on the transmission capacity of the existing network along with the cost benefit analysis, incremental effect on the tariff and details regarding the beneficiaries accountable to pay the transmission charges of the same.It has also been suggested that concerned state utilities/DISCOMS should also be involved in ISTS planning.

(b) Analysis and Recommendations of the taskforce

(i) The Taskforce observes that CERC has notified Central Electricity Regulatory Commission (Planning, Coordination and Development of Economic and Efficient Inter-State Transmission System by Central Transmission Utility and other related matters) Regulations, 2018 effective from 24.8.2018. The Regulations cover cost benefit analysis, incremental effect on the tariff. However the requirement of identification of who would be accountable to pay the transmission charges of the same has not been considered in the same. Under the current Poc regime, the allocation of transmission charges for a particular line depends on the base case file for that quarter. The charges would depend on ISTS drawl of the State, ISTS drawals of other States, total transmission charges for the system. Although projected base case file for a particular year may be built by CTU, however it may have following issues:

a. The transmission system under commissioning may not get commissioned.

b. The transmission system gets commissioned which is not envisaged as per current time frame

c. Load , generation scenario is different than expected.

(ii) In the above cases, the simulated results may not match the ex-ante computations made quarter ahead. Such differences may lead to litigations.

(iii) Further the referred Regulations mandates consultations with State discoms while transmission planning and uploading all the planning data transparently in public domain. The stakeholders should participate in transmission planning studies to gain confidence in the system being planned and provide their feedbacks to planning agencies.

4.9.23 NER to be considered as a block

(a) Assam representative suggested that NER should be considered as a block and PoC slab may be allotted on the basis of load profile of the region. Further, the intra-regional sharing of charges may be made in line with previously applicable UCPTT Charges.

(b) Analysis and Recommendations of the taskforce

The Taskforce has considered the suggestions. In case of treatment of region as a block few states will cross subsidize other states in the region. Any special treatment for a particular region is a policy matter and may be taken up at appropriate forum.

4.9.24 Locational based marginal pricing method

(a) A comprehensive method like locational based marginal pricing method suitably modified to fit in Indian scenario would be capable of addressing the shortcoming of the present methodology in view of the planned developments and market conditions.

(b) Locational based marginal pricing is a methodology to recover energy cost+ congestion cost. The issue under consideration is allocation of embedded cost of transmission. Hence LMP is not discussed here.

4.9.25 Treatment of counter flows

(a) Mr Vijay Menghani has suggested as follows on treatment of counter flows(negative marginal participation):

(i) In marginal participation method, the negative flows are neglected. The suggestion of few states that it should also be considered was examined in detail. In actual case study, it results in not only few nodes but whole zone as on net basis is becoming receivable for transmission charges. This results in say a hilly state getting crs of rs as transmission charges for withdrawing power from ISTS system. This also results in increasing of transmission charges for other utilities and spread of transmission charge (range of min and max) is increasing which is counter intuitive.

(ii) It is important to note that if full transmission network i.e ISTS and intra state transmission system is considered for recovery of transmission system charges and counter flows are considered, the above problem of some of the state becoming recipient of transmission charges may be removed. This is very difficult to implement as then CTU need to collect charges for all STUs also. Wherever counter flows are accounted for , the whole network is considered not a part thereof.

(iii) Why negative flows are not considered: the benefit of negative flow is realised only if line is congested i.e being used near its maximum capacity and then a transaction takes place to relieve it.

Suggestion: Counter flows may be not be considered unless tariff of full network both inter-state and intrastate tariff is to be recovered.

(b) **Analysis and Recommendations of the taskforce**

In light of suggestions, the taskforce suggests that counter flows should not be charged and their marginal participation should be taken as zero under modified PoC mechanism.Under Uniform charges the issue of counter flow doesnot arise.

4.9.26 Treatment of Grid Sub-stations

(a) Mr. Vijay Menghani, CEA has suggested that at present due to non availability of separate tariff for substation, YTC to be recovered through POC mechanism is allocated to lines. States are demanding that transformer should be represented separately. Similar view was expressed by CEA while commenting upon third draft amendment. CERC directed POSOCO to prepare methodology for the same. This need to be implemented as it will address concerns of the state utilities.For this norms may be decided by CERC to allocate a part of tariff of compete transmission system towards substation .

Suggestion: Substation tariff may be incorporated separately in POC computation

(b) Pradeep Jindal, CEA stated during taskforce meeting that presently, the costs attributed to the substations are not explicitly considered for calculation of PoC rates and neither the flow through the transformer is considered in the marginal participation algorithm for cost allocation of transformer branch. In this regard, it is important to note that the transformers are in fact branches having specific impedance and they must be treated in the same manner as the transmission lines. The methodology adopted for assigning per kilometer cost for various types of transmission lines i.e. 400 kV/ 765kV/ or SC/ DC or twin/Quad, etc. can be easily extended to include cost of substations based on voltage levels and MVA capacity. Ignoring perturbation through transformer impedance in the marginal participation algorithm would not be appropriate from electrical engineering point of view also. This should be put into practice right now, with any proof-of-concept attempts, because, it is a fundamental as simulation of transmission lines.This would also address the issue/concerns of some state like Orissa, Bihar, UP which are conduits for transmission of power to other states.

(c) POSOCO has agreed that the step-down transformers and downstream systems should be identified as separate elements. They have stated that ,the Inter-State Transmission System (ISTS) constitute a mesh, which provides the requisite redundancy and would be beneficial for all beneficiaries in a region, the step-down transformers and downstream systems (where presently included in ISTS) can be rationally identified as elements which serve only the local (one) beneficiary. Presently, charges corresponding to transformers are included in the total monthly transmission charges to be recovered. Transmission charges are assigned to each transmission line of ISTS licensees for recovery of total transmission charges.

These charges are assigned on the basis of average cost computed for different voltage levels and conductor configuration.

Prior to the introduction of the new transmission charges sharing mechanism (PoC) w.e.f. 1st July 2011, the transmission charges for 400/220 kV step down transformers (ICTs) and downstream systems, under inter-state transmission schemes brought under commercial operation after 28.03.2018 was determined separately (i.e. segregated from the rest of the scheme) and payable only by the beneficiary directly served. This formulation could also be re-considered so that the Yearly Transmission Charges (YTC) under the sharing mechanism reduces. It could however result in a situation where the state utilities would resist planning any ISTS substation in the state.

(d) Analysis and recommendations of the taskforce

(i) The issue of treatment of transformers as separate elements was raised during 3rd amendment to PoC Regulations by CEA. The relevant portion of SOR is quoted below:

"CEA has suggested that transformer should be included in computation as an element and its tariff can be taken based on Capital cost. This suggestion would be considered after doing some sample case studies and analysis of the results and its implication. Implementing Agency is advised do this exercise in consultation with IIT, Bombay and CEA."

(ii) It is observed that an issue of non-availability of separate tariff for ICTs was raised while discussions. However we have perused CERC Tariff Regulations 2009, Regulation 33(5) as quoted below:

> "(5) Transmission charges for 400 / 220 kV step down transformers (ICTS) and downstream systems, under inter-state transmission schemes brought under commercial operation after 28.03.2008 shall be determined separately (i.e. segregated from the rest of the scheme) and shall be payable only by the beneficiary directly served."

(iii) The above implies that separate determination of tariff for transformers was already in vogue. Further it is observed that a substation has line bays and ICT, an indicative cost of each capacity of ICT in grid substation can be arrived in the similar manner as being done for each type of transmission line in PoC calculations. These transformers may be modelled as a separate element so that their usage is captured and allocated to its user. In case they are modelled as separate element, in case of under utilisation, the cost for same may have to be loaded under residual cost. It is observed that there can be two types of transformers- used for drawal of power (mainly 400kV/ 2220 kV in most of the States) and another one used for injection of power (mainly 765kV/400 kV for eg. In Chattisgarh/ Jharkhand etc.). A tentative table of list of ICTs across India is placed below for reference:

Table 14: List of ICTs across India

State	Voltage ratio in use	Different capacity in use(MVA)	Total
Andhra Pradesh	400/220	315	18
Andhra Pradesh	400/220	500	8
Andhra Pradesh	765/400	1500	8
Arunachal Pradesh	132/33	15	7
Arunachal Pradesh	132/33	50	2
Assam	220/132	50	2
Assam	220/132	160	2
Assam	400/132	200	4
Assam	400/132	315	1
Assam	400/220	315	5
Bihar	132/33	10	2
Bihar	220/132	100	2
Bihar	220/132	160	4
Bihar	400/132	200	4
Bihar	400/220	315	8
Bihar	400/220	500	9
Bihar	765/400	1500	4
Chattishgarh	400/220	315	7
Chattishgarh	765/400	1500	21
Delhi	400/220	315	3
Delhi	400/220	500	2
Delhi	765/400	1500	4
Goa	400/220	315	3

State	Voltage ratio in use	Different capacity in use(MVA)	Total
Gujarat	400/220	315	13
Gujarat	400/220	500	4
Gujarat	765/400	1500	2
Haryana	400/220	315	21
Haryana	400/220	450	1
Haryana	400/220	500	12
Haryana	765/400	1000	2
Himachal Pradesh	400/220	315	7
Jammu & Kashmir	400/220	315	12
Jharkhand	220/132	160	2
Jharkhand	400/220	315	8
Jharkhand	765/400	513	1
Jharkhand	765/400	1500	2
Karnataka	400/220	315	8
Karnataka	400/220	500	17
Karnataka	765/400	1500	2
Kerala	400/220	315	9
Kerala	400/220	500	1
Madhya Pradesh	400/220	315	21
Madhya Pradesh	400/220	500	5
Madhya Pradesh	765/400	1000	4
Madhya Pradesh	765/400	1500	12
Maharastra	400/220	250	1
Maharastra	400/220	315	11
Maharastra	400/220	500	3
Maharastra	765/400	1500	11
Manipur	132/33	50	2
Nagaland	220/132	30	2
Nagaland	220/132	100	2
Orrisa	220/132	160	2
Orrisa	400/220	315	13
Orrisa	400/220	500	4
Orrisa	765/400	1500	6
Pondicherry	400/220	315	2
Pondicherry	400/220	500	1

State	Voltage ratio in use	Different capacity in use(MVA)	Total
Punjab	400/220	250	1
Punjab	400/220	315	14
Punjab	400/220	500	7
Punjab	765/400	1500	2
Rajasthan	400/220	315	17
Rajasthan	400/220	500	5
Rajasthan	765/400	1500	4
Sikkim	132/66	50	2
Sikkim	220/132	100	3
Sikkim	400/220	315	7
Tamil Nadu	400/220	315	20
Tamil Nadu	400/220	500	9
Tamil Nadu	765/400	1500	2
Tripura	132/33	5	1
Uttar Pradesh	220/132	100	1
Uttar Pradesh	220/132	200	2
Uttar Pradesh	400/220	315	22
Uttar Pradesh	400/220	500	11
Uttar Pradesh	765/400	1000	2
Uttar Pradesh	765/400	1500	16
Uttarakhand	220/132	100	4
Uttarakhand	400/220	315	4
West Bengal	220/132	50	1
West Bengal	220/132	160	6
West Bengal	400/220	315	11
West Bengal	400/220	500	3

(iv) The transformers which are commissioned to cater to drawal requirement of States should be billed to the State and other DICs should not bear burden for same. Hence, the taskforce recommends that all transformers which are used for drawal of power should be allocated to DICs of the state (drawal DICs). The transformers which are used for stepping up voltage and are primarily used for injection into the ISTS grid need to be billed to its user and hence has to be modelled seperately in PoC. This mechanism may be considered for modified PoC. A list of such transformers which are drawal transformers and injecting transformers may be provided by CTU in consultation with POSOCO.

(v) Under Uniform charges methodology, drawal transformers need to be billed to downstream entities and injecting transformers under Uniform charges.

4.9.27 Treatment of Connectivity Assets separately

(a) Mr. Vijay Menghani, CEA has suggested as follows:

(i) In nine HCTPC many assets are created for generating stations. Some part of this are connectivity assets which were to be used exclusively by generating stations or generating stations connected at that pooling points. Only after secondary side of transformer, transmission assets should be considered as part of common assets which will be considered in POC mechanism. As suggested in CERC staff paper in 2014 and adopted in most of the countries in National Grid UK, other countries of Europe, America etc , this system of connectivity assets should be applied at least to IPPS . CPSU generating station having full allocation of power can be exempted from this. This will unburden state DICs to the extent of about 15% transmission charges.

Also there are some clearly identifiable downstream system whose usage will always be attributed to a particular drawl node. The asset allocation principle followed in Australia is given below:

(ii) ElectraNet's and MTC's AARRs are recovered from transmission charges for the following categories of prescribed transmission services:

"

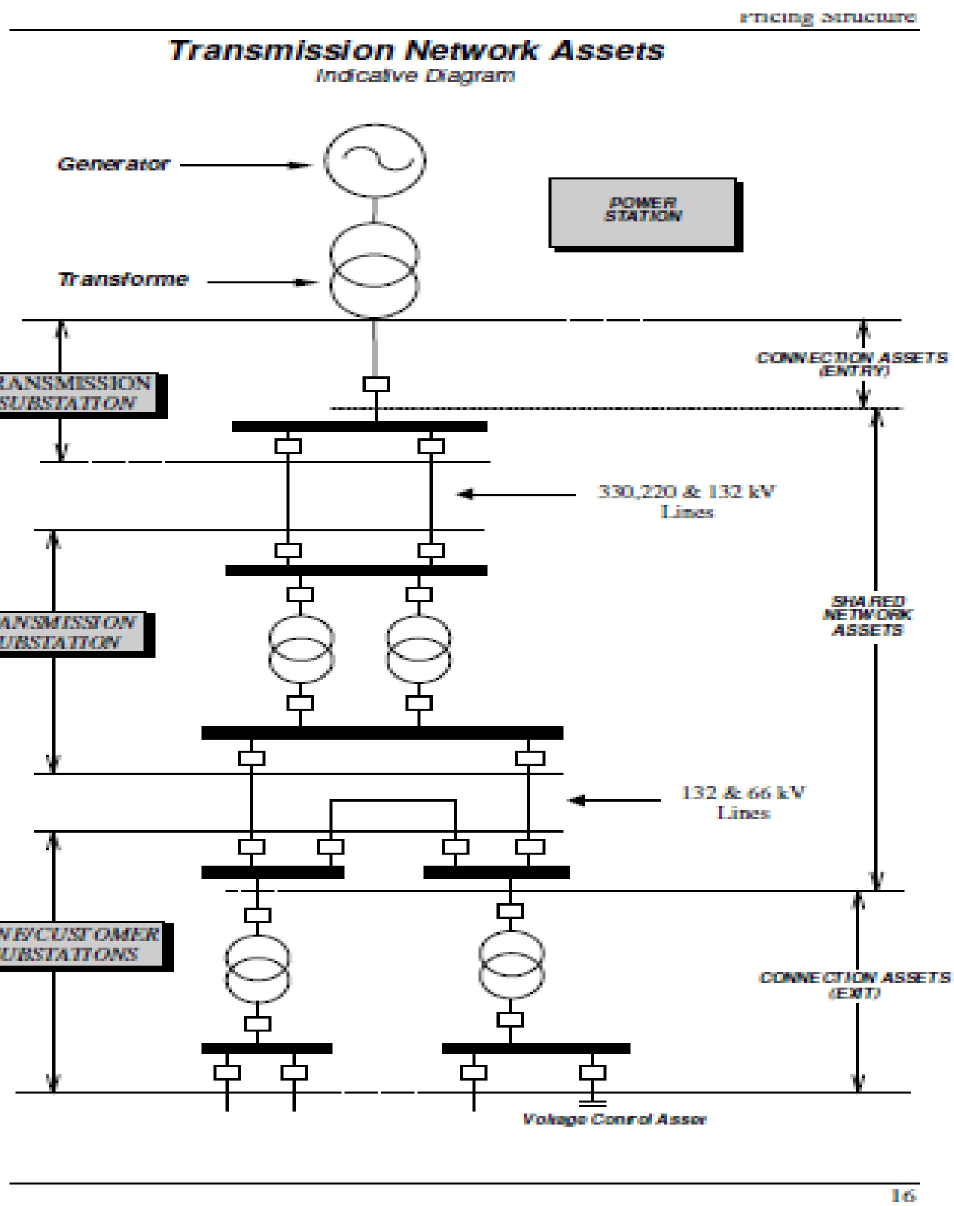
· **Prescribed entry services** which include services provided by assets that aredirectly attributable to serving a Generator or group of Generators at a singleconnection point and are deemed to provide a prescribed transmission serviceby virtue of the operation of clause 11.6.11 of the Rules;

· **Prescribed exit services,** which include services provided by assets that are

directly attributable to serving a Transmission Customer or group ofTransmission Customers at a single connection point and: (a) are deemed prescribed by virtue of the operation of clause 11.6.11 of the Rules; or (b) areexit services provided to Distribution Network Service Providers;

· **Prescribed common transmission services**, which are services that provideequivalent benefits to all Transmission Customers without any differentiationbased on their location, and therefore cannot be reasonably allocated on alocational basis; and

· **Prescribed transmission use of system (TUOS) services,**which include servicesthat provide benefits to Transmission Customers depending on their locationwithin the transmission system, that are shared to a greater or lesser extent byall users across the transmission system and are not prescribed commontransmission services, prescribed entry services or prescribed exit services.



(b) Analysis and Recommendations of the taskforce

The taskforce notes that dedicated line is under the scope of generator post 6th amendment to Connectivity Regulations. Further Grid substations have been suggested to be treated as separate elements under modified PoC mechanism. Under Uniform charges method, the transformers should be paid for by downstream entities or injecting entities as connection assets under bilateral billing. Hence the taskforce agrees that Connection assets should be charged to connecting entities.

4.9.28 IEX proposal on charging PoC rates for all intra-state entities in a consolidated manner

(a) IEX made a presentation on collective and bilateral transactions in exchanges. He described that there is a difference in POC pricing of intra-state bilateral vis-a-vis collective transactions. At present, intra state transactions bilateral are at a price advantage compared to collective transactions. He illustrated the price comparison in these transactions for Rajasthan. The landed cost of intra-state bilateral traded power is Rs. 4/u while it is Rs. 4.63/u for collective traded power, in state of Rajasthan. The difference of Rs. 0.63/u in them is due to injection POC rate (Rs. 0.32/u) and withdrawal POC rate (Rs. 0.32/u). To minimise the cost on account of PoC charges in collective transactions, IEX suggested netting of buy and sell quantum of a state. For example sell volume of a state is 40 MWhr and buactual scenarioy volume is 100 MWhr, then the net drawl for the state is 60 MWhr. This way, the state would incur POC charges only on its net drawl quantity, thereby reducing its POC charges. Further, IEX pointed that the STOA charges paid by a state DIC is reimbursed to them in manner of offset against their LTA. However, the STOA charges paid by intra state entities embedded in the state network are socialised to the advantage of other states as per the method of offset against LTA. IEX suggested that a DIC promoting open excess should be given the benefit offset.

He also requested that there should be intrastate power exchange to facilitate intra state transactions.

(b) Mr. S.K. Soonee rejected the idea citing following (i) Netting is cross subsidizing in nature and shifts the responsibility of POC to another entity (ii) Cost disagreements during times of market splitting. He further said that open access gives access to a larger market and therefore offsets within a state is detrimental to its regime.

(c) Shri S.S Barapanda expressed that charges collected from an embedded entity is passed on to the respective DIC.

(c) Shri S.A. Soman expressed that, in case injection / withdrawal is happening at the same node then in technical terms, there is netting; else there should be no netting. He further said offset benefit should be passed on immediately without lag.

(d) Chief Engg, CEA said that intra state transactions are cleared by respective SLDC as it is presumed to be used by intra state entities. However, in case of IEX transactions clearance is accorded by RLDC due to the interstate nature of the entities. Thus, both are not at par.

(e) Ms. Manju, AGM, CTU said that it is not right to treat power flowing in collective transactions to be separate from power in ISTS. Further, as long as the STOA is within the DIC LTA, benefit of offset is to be given to the state. Further it is only an assumption that all buy by embedded state entity is from the embedded seller within state but cannot be said with certainty.

(f) Analysis and Recommendations of the taskforce

The Taskforce observes that under the current regime, netting of transactions shouldnot be done. Further under GNA where all the charges will be levied on a State as one entity and transactions for intra-state entities are to be levied charges by the State itself. Hence the issue will not survive as the same shall have to be decided by the State.

4.9.29 Issue of different rates for adjoining buses

(a) SRPC vide letter dated 5.6.2018 stated that there is huge difference in POC rates when compared with its neighbouring plant ie., Meenakshi Energy Ltd. It is to kindly inform that both SEL and MEL are identically connected to 400 kV Nellore PG S/S through a common dedicated transmission system. It is also to bring to kind attention that SEL is not generating power since about past one year. Hence, average generation considered in the POC calculations in respect of SEL is zero. However, MEL had generated power and accordingly the average generation was considered in the POC calculation.

(b) Analysis and Recommendations of the taskforce

In this regard it is clarified that in case generation of plant is zero in aparticular base case , it is billed @ average of target region. Fifth amendment to Sharing regulations dated 14.12.2017 provides at regulation 8(7) as follows:

> "(7) DIC with LTA to target region whose POC rate has not been determined for the quarter, shall be billed at Average PoC rate of the target region."

In the instant case utilisation of ISTS by SEL in base case is zero but it has to be billed transmission charges as per contract. However MEL's rate represents its utilisation of ISTS. Hence both cases are not similar and hence not comparable.

4.10 Ex-ante vs ex-post?

(a) The current PoC mechanism is Ex-ante i.e the allocation of charges is decided based on projected load/generation for next quarter. There is no truing up carried out based on actual.

(b) Over the years States have come to know that reducing load and increasing generation in projection will result in lower charges. Once it is responsibility of payers to project their load/generation and almost no penalty for wrong projections (projections are projections after all which is uncertain), it has been more and more challenging at Validation Committee Meetings to conclude on load / generation figures since each figure has its associated commercial implications. It has been observed that different number of load/generation numbers are given for LGBR and for PoC by States.

(c) Internationally both types of methods are prevalent. In Australia the charges are determined post facto based on actual data. In a few Countries, the charges are determined ex-ante basis. It has been said that ex-ante provides siting signal. However based on the experience with PoC mechanism its can be concluded that it has not provided any siting signals to generators. It has definitely helped in removing market congestion since transmission grew at rapid pace with this mechanism

(d) If the transmission charges have to be shared based on utilisation, then utilisation is best captured on post –fact basis i.e based on actual scenario rather than projected one. This will be fair to all entities since present system works in advantage of entities managing to project less intentionally or due to forecasting errors.

4.11 Who should pay-generator or loads?

(a) Sharing regulations was effective from 1.7.2011. As per provisions of principal regulations, charges for both generation and load ends were determined. However for generators who have tied up their power under PPA, and transmission charges are to be borne by buyer, the POC charges as determined at generator end were billed to buyer. However such determination of POC charges at generation node and then billing to beneficiaries led to outcomes which were not distance, direction and quantum sensitive. Representative of CEA in meeting at MoP suggested that charges for both generation and load should be determined. The issue is discussed here in this context.

(b) PJM report states as follows in this regard covering international experience:

> "An overriding question is whether to assess costs to generators, load or both. In the vertically integrated utility environment prior to retail restructuring of the electric utility industry and the advent of organized wholesale power markets in much of the United States, generation and transmission were planned together and built to serve load. Operating under cost-of-service regulation, utilities were allowed to recover their costs and a return from the load they served.

Appropriately, all transmission costs were allocated to load with generation bearing none of the cost burden. Some parts of the country have not undergone retail restructuring and continue to use the vertically integrated model for transmission planning and cost allocation. In today's regulatory environment in which competitive generation and load conduct business on the transmission system in wholesale markets, there is the chance that both generation and load could be beneficiaries of new transmission upgrades/projects. It is not necessarily the case that new generation is built and existing generation maintained to serve specific loads. Instead, generation competes on a contract basis or through wholesale spot markets to serve load, which is no longer necessarily tied to a specific generator or set ofgenerators. All parties use the transmission system to either deliver generated energy to the market or withdraw that energy to serve load. Accordingly, some argue that it is appropriate in this environment for at least some transmission costs to be allocated to generation."

Allocating Costs to Load or Generation

The FERC in its recent Notice of Request for Comments asked whether "the determination of 'beneficiaries' of atransmission facility should include generators as well as loads."43 The answer will depend upon how the use ofthe term transmission system is interpreted, how beneficiaries are defined and whether such costs could or wouldultimately be passed through to loads.

One view is that all transmission costs will be passed through to loads in the wholesale market, as they are inthe vertically integrated regulatory environment. This assumes that generation will be able to recover the costof transmission, either through the wholesale energy market or through an existing wholesale capacity marketconstruct, or both. A similar view is that generation and transmission are constructed to benefit load in the sameway as in the vertically integrated environment, and therefore it is only the loads that are really beneficiaries oftransmission upgrades/projects.

A contrasting view is that new merchant generators also are beneficiaries of transmission projects in that
transmission facilities provide the means by which that merchant power can be delivered. This view is basedon the fact that for new interconnection, in some RTO markets, generators are required to pay for transmissionupgrades for delivery throughout the RTO, or to prevent reliability or deliverability criteria violations. Suchinterconnection costs can be considered part of the fixed cost (capacity cost) of generation. Because there isalready recognition that new generator interconnection may require transmission upgrades, it can be recognizedthat generators who may not need to pay for interconnection upgrades are beneficiaries of transmission facilities.

Allocating Costs to Load or Generation: U.S. Practices

As a general rule, all RTOs in the United States allocate the cost of transmission infrastructure to load. The
manner in which load is allocated cost and the rate design for cost recovery differ across RTOs, but load remainsresponsible for paying for transmission infrastructure.

As a general rule, generators interconnecting to the transmission system are responsible for the cost of directinterconnection facilities, except for a special case in the California ISO. This exception in the California ISOrelates to the interconnection of renewable resources, primarily wind. The California ISO has developed a newclass of transmission/interconnection facility known as a Locationally Constrained Resource Interconnection Facility (LCRIF). The costs of the LCRIF are allocated to load until resources are interconnected to the LCRIF,but once a generator is interconnected, it pays for its contribution on the LCRIF as determined by the capacityof the interconnecting generator.

In some RTO contexts generators are responsible for paying some transmission infrastructure costs over and abovethe cost of interconnection facilities. Currently, these are specific to generator interconnection rather than partof the general cost allocation method for the bulk of transmission infrastructure. For example, in PJM, New YorkISO and ISO New England generators requesting interconnection to the transmission system must pay for 100percent network upgrades beyond the necessary interconnection facilities in order to alleviate potential reliabilityviolations of their interconnection, to ensure deliverability as a capacity resource, or meet other interconnectionrequirements.45 In the Midwest ISO generators pay for most upgrade costs, except for select transmission zones,while in the Southwest Power Pool (SPP) only wind resources may be subject to paying for interconnectionupgrades.46 In this way, some generators are paying for transmission. There may be instances in which generatorsrequesting interconnection do not cause reliability violations or have any deliverability problems. In these cases,generators only pay for their direct interconnection facilities.

Generators interconnecting in ERCOT and the California ISO are not responsible for any transmission upgradecosts resulting from interconnection as they are allocated entirely to load.47
To the extent generators are responsible for cost of transmission upgrades should they be necessary, the needfor generators to pay for network upgrades is a function of their place in the interconnection queue and forecastsystem conditions. Consequently, generators have incentives to try to manage positions in the interconnectionqueue by strategically withdrawing and re-entering the queue in order to potentially avoid paying for networkupgrades.

Finally, there is now a preliminary proposal, being circulated in the Midwest ISO to shift some costs to generatorsin what is being called an "Injection/Withdrawal" proposal. Under the Midwest ISO proposal costs for highervoltagetransmission facilities would be split between load and generation.

Allocating Costs to Load or Generation: International Practices

Internationally, there is a greater acceptance of generators being allocated some costs associated withtransmission infrastructure. Within the European Union (EU) where electricity competition is the standard policy,there is a wide variance in how much transmission infrastructure cost is allocated to generation. In 13 countries,including Spain, the Netherlands, Belgium and Germany, generators are not allocated any portion of the cost oftransmission infrastructure.49 However, there are 12 other EU member countries where generation is allocatedsome portion of transmission cost, ranging from a half percent in Poland to 35 percent in Norway, as shown in

Table 4. These countries combined are approximately one-third the size of the U.S.

Table 4: Relative Shares of Transmission Costs Allocated to Generation and Load in European Countries

Country	Percent to Generation	Percent to Load
Austria	18	82
Denmark	2-5	95-98
Finland	12	88
France	2	98
Great Britain	27	73
Greece	15	85
Ireland	20	80
Italy	8	92
Norway	35	65
Poland	0.5	99.5
Romania	22.62	77.38
Sweden	25	75

Source: European Transmission System Operators, ETSO Overview of Transmission Tariffs in

Europe: Synthesis 2008, June 2009, at 6, available at http://www.entsoe.eu/fileadmin/user_upload/_library/publications/etso/tariffs/Final_Synthesis_2008_final.pdf

It is interesting to note that EU countries with mature or organized wholesale energy markets similar to the U.S.RTO markets, such as Great Britain; NordPool countries (Norway, Sweden, Denmark and Finland) and Ireland,do generally allocate some portion of transmission cost to generators, as shown in Table 4, though it differssignificantly by country. In contrast, Spain, which operates a centralized spot market similar to U.S. RTO markets,allocates all transmission costs to load, as do Belgium and the Netherlands in which power is actively traded onindependent exchanges.

In other parts of the world where wholesale energy markets are in operation, transmission costs are often allocatedto generation as well as load, though not universally, as is the case in Australia. Singapore where load is 100percent responsible for transmission costs.50In South America, specifically Brazil and Chile, generation bears a relatively large share of transmission costs.The exact cost breakdown for Argentina is not known or been reported, but given the methodology, the cost shareis potentially quite large for some generators far from the load center in Buenos Aires.51 In South Korea, whichoperates a simpler type of market known internationally as a single-buyer market, cost allocations are evenly splitbetween generation and load.52 In New Zealand, the general rule is to allocate transmission costs to load, exceptfor the cost of the high-voltage direct current (HVDC) link between the two main islands (North and South), whichis allocated entirely to the generation on the South Island.

Table 5: Relative Shares of Transmission Costs Allocated to Generation and Load in Other Selected Countries with Wholesale Power Markets

Country	Percent to Generation	Percent to Load
Australia	0	100
Brazil	50	50
Chile	80	20
New Zealand	100% to HVDC link between North and South Island. 0% for remainder.	100% of all transmission and 0% HVDC link
Singapore	0	100
South Korea	50	50

Source: Frontier Economics, International Transmission Pricing Review: A Report Prepared for the New Zealand Electricity Commission, July 2009, at 28-33, available at http://www.electricitycommission.govt.nz/pdfs/opdev/transmis/tpr/International-transmission-pricing-review.pdf

(c) The Commission while issuing 3rd amendment to sharing Regulations dealt with the issue extensively as under:

"33.178 Currently the transmission charges are calculated as Injection POC and Withdrawal POC separately. The charges assigned to generation nodes are billed to beneficiaries of the generating station in proportion to their allocation from such generating station. In India such long term transactions are of the order of 90%, where beneficiaries are finally loaded with generation POC charges. The power generated from generating stations flows as per laws of physics depending on demand scenario. This power may be actually absorbed by such States where demand is more and not by the State who has the allocation of power. Software gives sufficient insight in regard to tracing of power from the generator to demand nodes and it clearly demonstrates that it is either not going to beneficiary at all or quantum reaching the beneficiary has no relationship with % allocation. The issue was raised for stakeholders' comments vide the Explanatory Memorandum to Draft Regulations.

33.18 GRIDCO has welcomed the proposal of allocation based on participation factor as it will capture the actual usage of generator for drawing its approved quantum of power. Bihar has also raised the issue that under PoC methodology allocation of power from a generation plant has lost its significance because it is not necessary that allocated power is coming to the beneficiary from the same generation plant from which power is allocated.

33.19 We have considered suggestions of Bihar and GRIDCO. The National Electricity Policy specifies that the transmission charges should be reflective of distance, direction and quantum of usage. However due to billing of generation end transmission charges to beneficiaries based on their share of power in such generating stations, the final charges loaded to beneficiaries become non reflective of distance, direction and quantum of usage. We have therefore decided that charges shall not be calculated separately for generation end where generators have a contract for long term supply to identified beneficiaries. The charges shall rather be calculated only at the Withdrawal nodes so that charges reflect usage of lines by a particular Withdrawal node/zone.

33.20 It is true that for power market, separate injection rates are required for generators. In European countries where separate injection rates are given, generators sell their output in day ahead power market and information is very much required there. But in a country with 90% power allocation being in long term, the information given in Rs/MW/month will not have much use in power market where transactions are based on energy. Therefore, in order to facilitate generators to participate in power market, transmission charges in paise/kWh are given. For long term beneficiaries, allocation of transmission charges in proportion to their share shall be discontinued and transmission charges only based on usage shall be recovered. To give effect to this, after first stage computation, the injection charges of generator who have identified beneficiaries will not be calculated. With already available information of marginal factor, the transmission charges will be allocated only to drawee entities and generators having long term access to target region.

33.21 The calculations as explained above resolves following cases also:

(i) A sample case study for Talcher TPS Stage-I (Q4 2013-14) from which power is allocated to ER and few constituents of SR and NER was done and following results emerged:

While Odisha has allocation of about 32% in Talcher Stage-I, actually 83% of Talcher power is consumed in Odisha. Bihar has allocation of 43% in the station but no power flows to Bihar from the station. Therefore, seeking payment of injection charges on the basis of allocation is not reflective of actual usage.

(ii) Set point for HVDC: GRIDCO in its letter dated 23.7.2014 brought the issue of high injection POC rate for Talcher STPS- I after synchronization of SR grid with NEW grid. It is stated that injection PoC rates of TSTPS-I which were in the lower slab of Rs.1,14,425/- per MW per month till March, 2013 were Rs.1,17165/- per MW per month during the first quarter of 2014-15. It is found that power is forced to be flown from TSTPS-I to Southern Region through Talcher-Kolar HVDC system, since the HVDC control is 2000 MW. The schedule generation of stage-2 of Talcher during the first quarter of 2014-15 was kept at 1592 MW and hence approximately 408 MW power was considered to be supplied from Stage-I. Similarly during the second quarter of 2014-15, the schedule generation of stage-2 was considered as 1314 MW and approximate 686 MW inrushes to SR through Talcher-Kolar due to HVDC setting of 2000 MW. Hence such power flow form stage 1 cannot be considered as actual flow as per law of physics, rather the same may be termed as artificial flow, such flow to SR is resulting in high injection PoC charges of Talcher stage 1 and burdening its allottees. In the present quarter (second quarter of 2014-15, the schedule generation of TSTPS-1 is only 718 MW out of which flow of 686 MW is to SR and only 32 MW is injected to ER for which the allotees of Talcher stage 1 have to pay total injection PoC of TSTPS-1, that to at higher slab rate. On the other hand this power though almost completely utilized by SR beneficiaries, they have to pay nothing since they have no allocation from Talcher stage-1. However, it is observed that for optimal use of Talcher-Kolar link and keeping in view the load requirement in SR, power would be forced to flow from TSTPS-I to SR through SR has got no allocation from the said generator. This problem shall get solved through the new methodology since injection charges for Talcher shall not be calculated and only drawal charges for drawing DICs shall be calculated.

For set point of HVDC one more observation is important. It was found that the HVDC set point considered in the study for PoC computation and operational set point was different in case of HVDC Balia–Bhiwadi. As the same base case is being used for allocation of losses, it is necessary that operational situational is correctly captured in allocation of PoC charges and losses. A different set point affects relative usage of AC lines. The Implementing Agency, therefore, should consider the set point corresponding to near actual scenario.

33.23 The issue of high transmission charges of DICs in exporting region even when the DICs are located near the generating station was flagged in the Explanatory Memorandum and effect of allocation based redistribution of injection charges on sensitivity to distance and direction was discussed and suggestions were sought from stakeholders on this issue. After considering three possibilities i.e. allocation of injection charges based on shares in the generating station, participation factors of drawal nodes in the particular generating stations and directly allocating injection charges to withdrawal nodes, this methodology was found technically correct and it addresses the issue of transmission charges of DICs of exporting regions. In this methodology, the basic principle of PoC mechanism i.e. the charges of transmission assets are payable by the entity who actually uses it and hence usage, distance and direction sensitivity is captured.

33.24 In the prevailing mechanism it is important to see how generators allocate the transmission charges allocated to it further. In India, as most of central sector generating stations having PPA sell power at generator bus, they do not bear the transmission charges. It is their beneficiaries who arrange for transmission system. Thus, even at present, these generators are not billed for transmission charges for injection; rather these injection charges are allocated to their beneficiaries in the ratio of their share in the generating stations. This introduces a situation wherein injection charges computed based on usage, are allocated based on contract. A DIC then has to pay withdrawal charges computed based on usage which is sensitive to relative spatial distance between generators and load points and the injection charges which are based on allocation. A DIC when it considers its total bill and compares it with others' usages, just compares physical distance form a particular generator in which both of these are beneficiary, finds that even though it is located near the generator, it is paying more transmission charges.

33.25 Similarly a DIC which is located near new generating stations find a typical scenario that for withdrawal portion, its power is coming from nearby generator, but for injection portion it is paying for a far off generator and for lines in which it does not have any Marginal Participation.

33.26 The generation POC charges as calculated currently, reflect actual usage of transmission system by the generator's power and not usage by beneficiary of such power. Removing such generation POC charges and allocating transmission charges only to demand zones based on their actual usage of lines will allocate transmission charges on the basis of actual usage by beneficiaries and not on the basis of theoretical allocation of power. However, for Generators who have LTA to target region and do not have identified long term beneficiaries, generation end POC charges shall be calculated and billed to respective generators for such supply for which long term beneficiaries have not been tied up. Such generators shall be liable to pay only the injection charge for such untied quantum. The Withdrawal DICs shall pay for only the Withdrawal Charges. By such modifications, each Withdrawal DIC shall pay for the lines which it is actually using for drawal of power. Hence, Delhi shall pay for inter-State transmission lines from which it is drawing power and similarly Bihar shall pay for lines which it utilizes to draw power and not for the lines on which power from Kahalgaon travels to Northern Region/Western Region. The point made by Bihar that the lines created under ER system strengthening for evacuation of ER surplus power beyond ER are being charged to ER beneficiaries, will get addressed since charges for such lines shall be paid for by the beneficiaries who are actually drawing power through such lines.

33.27 We have considered the suggestions of BSPCL and have modified determination of POC charges only on load points and specified generation points. This amendment shall make the injection charges levied on beneficiariesas per their usage of transmission lines and not as per their allocation of power.

33.28 Bihar has commented that "NLDC for computation of the Injection & Withdrawal transmission charges based on PoC methodology has considered electrical distance in spite of the physical distance at its own which is against the provision of Clause 5.3.5 of the National Electricity Policy notified on 12.2.2005 and Clause 7.1 (2) of the National Tariff Policy notified on 6.1.2006". In this regard it is mentioned the clause of National Electricity Policy and National Tariff policy quoted by Bihar specifies that "the tariff mechanism would be sensitive to distance, direction and related to quantum of flow" which implies that tariff should be reflective of its actual usage which can best be represented by "electrical distance" and not the "physical distance" of contract. Hence, the spirit of POC methodology is very much in line with National Electricity Policy and Tariff policy. Also we are not in agreement with the BSPL views that the assumptions made in computation of PoC charges make sharing of transmission charges illogical. The assumptions were agreed after detailed deliberation in six meetings of implementation committee in 2010-11. These assumptions are discussed in validation committee and also Commission approves assumptions made in computation of PoC charges for each quarter.

33.29 We have considered the contention of Bihar that it is paying charges for lines not being used by it. Accordingly we have amended Regulation 17 which provides for sharing of information. The lines being used by each DIC as per the software output shall be clearly listed out and published for information of stakeholders by the nodal agency on its website.

33.30 We proposed in the draft amendment for allocation of generation end charges on participation factor basis. However we are not inclined to consider the same since allocation of generation end charges may lead to allocation of charges for such lines to a beneficiary which is not using them. For example, if power from Kahalgaon STPS of NTPC is reaching Delhi, U.P. and Rajasthan in the ratio of 20%, 30% and 50% respectively. Let us suppose lines used for transfer of power of Kahalgaon to Delhi, UP and Rajasthan are 2nos 400 kV lines, 4nos 765 kV lines and 4nos 400 kV lines respectively. The generation end charges shall be calculated as sum total of lines used for transfer of 20%, 30% and 50% power to Delhi, U.P. and Rajasthan respectively. The sum of transmission charges corresponding to all the lines being used by Kahalgaon shall be allocated to Delhi as 20%, U.P. as 30% and Rajasthan as 50%. The aggregate whose percentage shall be shared between Delhi, U.P. and Rajasthan shall include the lines being used for transfer of power for other beneficiaries also and hence is non reflective of charges being allocated on usage basis. Hence generation end charges shall not be allocated on participation factor basis but shall be calculated only for withdrawal nodes and specific generation nodes with untied capacity under LTA.

33.31 The decision to arrive at revised methodology has been taken after considering all options and testing their effectiveness to resolve this issue and considering its implications.

33.32 An illustrative example for Kahalgaon STPS is given below, considering the following

(a) Allocation of transmission charges due to contract

(b) Allocation due to participation factor

(c) Transmission lines which are being used by Kahalgaon

(d) Transmission lines which are being used by Bihar.

(e) The additional lines which were shared by Bihar due to its allocation in Kahalgaon even if withdrawal nodes of Bihar have no marginal participation in these lines.

Q2 Truncated Network Average Case 2014-15		
STATE	**Percentages Allocation as per participation**	**Percentage allocation as per ERPC July 2014 Bill**
Bihar	36.92	42.15
Haryana	20.12	3.04
UP	15.90	9.12
Rajasthan	13.70	3.04
Punjab	6.60	6.07
Uttarakhand	3.54	0
Jharkhand	2.07	3.28
Delhi	1.15	6.07
DVC	0	0.59
ODISHA	0	15.56
West Bengal	0	0.64
Sikkim	0	1.55
TAMILNADU	0	0.7
J&K	0	3.68
Assam	0	2.27
Nagaland	0	0.42
ARUNACHAL AL	0	0.19
MIZORAM	0	0.14
POWERGRID(PASAU	0	0.15
NVVN POWER A/C BPDB	0	1.19
TOTAL	100%	100%

33.32.1 It can be seen that while participation factor though software indicates BIhar getting 36.92% of power from Kahalgaon, allocation of power to Bihar from Kahalgaon is 42.15 %. Hence injection charges of Kahalgaon to the extent of 42.15 % are shared by Bihar under present methodology.

33.32.2It is further noticed that there are lines which are used by Kahalgaon node but not by Bihar as detailed below:

- Number of Lines used by Kahalgaon : 420Lines
- Number of Lines used by Bihar: 545 Lines
- Number of Lines used both Kahalgaon and Patna (Common Lines used): 396Lines
- Number of lines used by only Kahalgaon not Bihar: 24Lines
- Number of lines used by only Bihar not Kahalgaon : 149Lines

Hence it can be seen that if injection PoC charges of Kahalgaon are allocated to Bihar based on its allocation in Kahalgaon, it shall have to bear additional charges for 24lines used by Kahalgaon and not by Bihar.

33.33 The change in methodology for allocating injection charges is not merely to resolve the issue of transmission charges of exporting region but is also required to address the transmission planning and execution. It is necessary to remove misconception of some of the DICs that creation of transmission infrastructure for new generating stations increases home State's transmission charges. This misconception was due to the reason that withdrawal DICs pay for transmission charges of nearby transmission system, and they continue to pay for injection charges of generators in which they have allocation whereas power actually does not come from these generators. Actually, the position is reverse. By having a new generating station at a new location, the extent of transmission network usage reduces, as power is received from spatially closer generating stations. The benefits accrue to such Withdrawal DICs since it leads to reduction in Withdrawal Charges. For example, if in a particular scenario in an application period, Odisha is not receiving power from Tala and power is reaching to it on displacement basis from nearby Generating stations using shorter length of transmission lines, this misgiving/misconception can be removed to a large extent and it will create a conducive environment for transmission system development. Also opposition to transmission system for nearby generating station due to its multiple buyers spread across the country would diminish and insistence of home State on seeking separate line for itself for availing power from this station would decrease. Optimal Transmission system planning needs to focus on planning and utilizing the transmission assets in a collectively efficient way, thus obviating the need for duplication of assets. Practical example of this is available in the form of reduction of withdrawal transmission charges of Odisha after commissioning of IPPs in Orissa.. From other similar studies for Q2 2014-15 scenario, it emerges that methodology now finalized solves the problems of States of exporting region.

33.34 So keeping the basic philosophy of PoC computation in mind that an entity should pay for only those transmission assets which it uses, it has been decided that for generator having beneficiary, the injection charges shall not be declared. For generator having LTA for target region, injection charges to the extent of untied capacity shall be computed. This is accordingly provided in Regulation 8(6) of the Sharing Regulations.

33.35 However, if in a particular contract, the Generator has itself taken the responsibility for paying transmission charges upto load end, it will pay the transmission charges to the extent of contracted capacity. For example if a generator X is selling 400 MW to TANGEDCO, then out of total withdrawal charges of TANGEDCO, this generator will pay withdrawal charges for 400 MW. Either TANGEDCO will be billed for total withdrawal charges and then it can take payment from Generator or it can inform billing agency that Generator will pay these charges.

33.36 The allocation of transmission charges to only withdrawing entities will serve purpose in case of Case I bidding wherein the procurer States/DISCOMS will consider the same withdrawal charges for all bidders irrespective of their location.

The Commission had also raised the issue in the draft amendment about the State embedded generators using ISTS but not paying ISTS Charges. The amendment providing of calculation of charges only on withdrawal nodes will take care of charges for the usage of ISTS by State generators. Since majority of power from such intra-state generators is consumed within the state, the transmission charges for use of ISTS by these intra-State generators shall automatically be attributed to State DISCOMs under the methodology as per third amendment . Earlier the usage of ISTS by embedded generators of a State was calculated under the base case. However, such charges were being recovered through scaling up. Under the methodology as per this amendment, the charges attributable to such generation shall automatically be attributed to the concerned State(s).

33.37 To facilitate participation of all generators in power exchanges, and for the purpose of STOA, collective transactions and computation of transmission deviation charges, POC injection rate/withdrawal rate for all DICs shall be determined separately and shall be declared in paise/kWh. These rates shall be other than the rates specified for billing under Bill No. 1 of Regulation 11. The injection and withdrawal rates in paise/kWh shall be computed before transferring injection charges of ISGS having long term customers on withdrawal DICs. Hence these rates shall be determined for zones including generators with identified beneficiaries”

(d) **Analysis and Recommendations of the taskforce**

The taskforce observes that a majority of generators have contracts for ex-bus sale of power. The responsibility to pay transmission charges in these cases is with buyers/load. Hence there is no benefit in calculating the charges separately for these generators for billing to beneficiaries in some ratio which may create distortions as acknowledged in 3rd amendment SOR. The current methodology of determination of transmission charges on the loads in case buyer is identified and on generator for cases where buyer is not identified should continue.

TOR 4: To assess the status of availability of data and data telemetry in order to facilitate shifting towards actual scenario than the estimated scenario as done currently;

4.12 Status of availability of data and data telemetry in order to facilitate shifting towards actual scenario

4.12.1 The requirement of shifting to actual scenario shall require timeblockwise data of generation and demand at all the nodes across India. For the ISTS nodes RLDC receives this data for the purpose of accounting. However the data for intra-state nodes are not available at all places. Integration of RTUs is in progress in States. We have perused status of data telemetry across India which is monitored by respective RLDCs. The report by NLDC for status of telemetry as on 31.12.2018 provides as follows:

Table 15: All india regionwise telemetry status as on 31.12.2018

Regionwise Summary of Telemetry Status as on 31.12.2018

Sl. No.	Region	Total Nos of Stations		Telemetry not Provided		Telemetry Intemittent		Total non-availability of data in % (Telemetry not provided plus Telemetry intermittency)	
		GS	SS	GS	SS	GS	SS	GS	SS
1	NR	148	833	0	105	18	90	12%	23%
2	WR	197	726	0	30	5	97	3%	17%
3	SR	287	547	21	11	29	22	17%	6.0%
4	ER	106	397	5	20	8	37	12%	14%
5	NER	26	150	3	21	13	94	62%	77%
	TOTAL	**764**	**2653**	**29**	**187**	**73**	**340**	**13%**	**20%**
	Total (over all)	**3417**		**216**		**413**		**18%**	

Table 16: Northern region telemetry status as on 31.12.2018

Northern Region summary sheet and details of current status of implementation of telemetry system												
								Updated Till:			31.12.2018	
User Name	Total Nos of Stations		Telemetry not Provided				Telemetry Intemittent				Total non-availability of data in % (Telemetry not provided plus Telemetry intermittency)	
			Total nos of station		Non-availability of data in % (wrt total nos of stations)		Total nos of station		Non-availability of data due to intermittency in % (wrt total nos of stations)			
	GS	SS	GS	SS	GS	SS	GS	SS	GS	SS	GS	SS
Punjab	17	173	-	92	-	53%	1	17	6%	10%	6%	63 %
Haryana	5	70	-	13	-	19%	-	1	-	1%	-	20 %
Rajasthan	20	204	-	-	-	-	-	5	-	2%	-	2%
Delhi	6	43	-	-	-	-	-	4	-	9%	-	9%
UP	22	174	-	-	-	-	3	44	14%	25%	14%	25 %
Uttarakhand	10	29	-	-	-	-	4	4	40%	14%	40%	14 %
HP	15	25	-	-	-	-	2	-	13%	-	13%	-
JK	4	17	-	-	-	-	3	11	75%	56%	75%	56 %
POWERGRID	-	80	-	-	-	-	-	3	-	4%	-	4%
NTPC	14	-	-	-	-	-	2	-	14%	-	14%	-
NHPC	14	-	-	-	-	-	2	-	14%	-	14%	-
NPCIL	5	-	-	-	-	-	-	-	-	-	-	-
NJPC	2	-	-	-	-	-	-	-	-	-	-	-
THDC	2	-	-	-	-	-	-	-	-	-	-	-
BBMB	6	16	-	-	-	-	-	-	-	-	-	-
IPP/JV/Patran	6	2	-	-	-	-	1	1	17%	50%	17%	50 %
TOTAL	148	833	0	105	0%	13%	18	90	12%	11%	12%	23 %
Total (over all)	981		105		11%		108		11%		22%	

Note:

1. Constituentswise details is as furnished by SLDC's / as available at RLDC.

2. 'GS' Generating Stations and 'SS' subStations

Table 17: Western region telemetry status as on 31.12.2018

	Western Region summary sheet and details of current status of implementation of telemetry system													Annexure - IV	
											Status as on :			31.12.2018	
Sl. No.	User Name	Total Nos of Stations		Telemetry not Provided				Telemetry Intemittent						Total non-availability of data in % (Telemetry not provided plus Telemetry intermittency)	
				Total nos of station		Non-availability of data in % (wrt total nos of stations)		Total nos of station		Non-availability of data due to intermittency in % (wrt total nos of stations)					
		GS	SS	GS	SS	GS	SS	GS	SS	GS		SS		GS	SS
1	Maharastra	32	195	0	1	0.0%	0.5%	1	34	3.1%		17.4%		3.1%	17.9%
2	Chattisgarh	6	118	0	26	0.0%	22.0%	3	55	50.0%		46.6%		50.0%	68.6%
3	Madhya Prdesh	17	181	0	0	0.0%	0.0%	0	1	0.0%		0.6%		0.0%	0.6%
4	Gujarat	101	172	0	1	0.0%	0.6%	0	5	0.0%		2.9%		0.0%	3.5%
5	Goa	3 Nos of IPP's	7	3 Nos of IPP's	0	100.0%	0.0%	0	0	100.0%		0.0%		100.0%	0.0%
6	DD	-	1	-	-	-	-	-	-	-		-		-	-
7	DNH	-	4	-	2	-	50.0%	-	2	-		50.0%		-	100.0%
8	ISGS	17	-	-	-	-	-	0	-	0.0%		-		0.0%	-
9	ISTS	-	48	-	0	-	0.0%	-	-	-		-		-	0.0%
10	IPP	24	-	-	-	-	-	1	-	4.2%		-		4.2%	-
	TOTAL	197	726	0	30	0.0%	4.1%	5	97	2.5%		13.4%		2.5%	17.5%
	Total (over all)	923		30		3.3%		102		11.1%				14.3%	

Note:

1 Supporting Details are given below

2 Communication between all SLDCs to WRLDC is in radial mode in ULDC network and any failure in any equipment /Fibre leads to total data black out.

Table 18: Southern region telemetry status as on 31.12.2018

	Southern Region summary sheet and details of current status of implementation of telemetry system												
										Updated Till:		31-12-2018	
Sl. No.	User Name	Total Nos of Stations		Telemetry not Provided				Telemetry Intemittent				Total non-availability of data in % (Telemetry not provided plus Telemetry intermittency)	
				Total nos of station		Non-availability of data in % (wrt total nos of stations)		Total nos of station		Non-availability of data due to intermittency in % (wrt total nos of stations)			
		GS	SS	GS	SS	GS	SS	GS	SS	GS	SS	GS	SS
1	Andhrapradesh	92	126	12	0	13%	0%	18	4	20%	3%	33%	3%
2	Telangana*	84	94	9	10	11%	11%	1	7	1%	7%	12%	18%
3	Karnataka	23	106	0	0	0%	0%	0	1	0%	2%	0%	2%
4	Kerala	13	41	0	0	0%	0%	1	2	8%	5%	8%	5%
5	Tamilnadu	47	122	0	1	0%	1%	4	6	9%	5%	9%	6%
6	Pondicherry	-	4	-	-	-	-	-	1	-	25%	-	25%
7	POWERGRID	-	54	-	-	-	-	-	1	-	2%	-	2%
8	NTPC	6	-		-	0%	-	1	-	17%	-	17%	-
9	NLC	4	-	-	-	-	-	1	-	100%	-	25%	-
10	NPCIL	3	-	-	-	-	-	0	-	0%	-	0%	-
11	IPP/JV/Others	15	0	-	-	-	-	3	-	20%	-	20%	-
	TOTAL	287	547	21	11	7%	2%	29	22	10%	4%	17%	6%
	Total (over all)	834		32		4%		51		6%		10%	

Note:

1. Constituentswise details is as furnished by SLDC's / as available at RLDC.
2. Status considered above are grid substation and upto 132 KV voltage level.
3. 'GS' Generating Stations and 'SS' subStations
4. **Some of the GS/SS are integrated, however, due to availability of partial data it has been considered as telemetry not-provided.**

* 132 kV substations have been removed from list of total no of substations,
as only 220 kV voltage level & above substations are being considered for gridmonitoring.

Table 19: Eastern region telemetry status as on 31.12.2018

Eastern Region summary sheet and details of current status of implementation of telemetry system — **Annexure - VII**

Status as on : 27.12.2018

Sl. No.	User Name	Total Nos of Stations		Telemetry not Provided				Telemetry Intemittent				Total non-availability of data in % (Telemetry not provided plus Telemetry intermittency)	
				Total nos of station		Non-availability of data in % (wrt total nos of stations)		Total nos of station		Non-availability of data due to intermittency in % (wrt total nos of stations)			
		GS	SS	GS	SS	GS	SS	GS	SS	GS	SS	GS	SS
1	West Bengal	19	71	-	2	-	2.8%	5	13	26.3%	18.3%	26.3%	21.1%
2	Bihar	2	106	-	16	-	15.1%	-	8	-	7.5%	-	22.6%
3	DVC	12	36	-	-	-	-	-	-	-	-	-	-
4	Jharkhand	2	25	-	2	-		-	6	-	24.0%	-	32.0%
5	Odissa	49	111	5	-	10.2%	-	2	8	4.1%	7.2%	14.3%	7.2%
6	Sikkim	-	2	-	-	-	-	-	-	-	-	-	-
7	POWERGRID	-	42	-	-	-	-	-	-	-	-	-	-
8	NTPC	10	1	-	-	-	-	1	1	10.0%	100.0%	10.0%	100.0%
9	NHPC	2	-	-	-	-	-	-	-	-	-	-	-
10	IPP/JVs/Others	10	3	-	-	-	-	-	1	-	33.3%	-	33.3%
	TOTAL	106	397	5	20	4.7%	5.0%	8	37	7.5%	9.3%	12.3%	14.4%
	Total (over all)	503		25		5.0%		45		8.9%		13.9%	

Note:
1. Constituents-wise details as per data available at ERLDC
2. 'GS' Generating Stations and 'SS' sub-Stations
3. Status considered above are grid sub-station and upto 132 KV voltage level.
4. Partial data available means if any part of the elements like Bus-Voltage/frequency/analog/degital/reactors is under suspect condition/not 100%.

Table 20: Northe-Eastern region telemetry status as on 31.12.2018

North Eastern Region summary sheet and details of current status of implementation of telemetry system — **Annexure - VII**

Status as on : 26.12.2018

Sl. No.	User Name	Total Nos of Stations		Telemetry not Provided				Telemetry Intemittent				Total non-availability of data in % (Telemetry not provided plus Telemetry intermittency)	
				Total nos of station		Non-availability of data in % (wrt total nos of stations)		Total nos of station		Non-availability of data due to intermittency in % (wrt total nos of stations)			
		GS	SS	GS	SS	GS	SS	GS	SS	GS	SS	GS	SS
1	AEGCL	4	63	-	-	-	-	3	56	75.0%	88.9%	75.0%	88.9%
2	MeECL/MePTCL	7	16	-	-	-	-	5	14	71.4%	87.5%	71.4%	87.5%
3	TSECL	3	22	-	-	-	-	3	19	100.0%	86.4%	100.0%	86.4%
4	POWERGRID	-	22	-	-	-		-	2	-	9.1%	-	9.1%
5	NEEPCO	6	-	-	-	-	-	1	-	16.7%	-	16.7%	-
6	NHPC	1	-	-	-	-	-	1	-	100.0%	-	100.0%	-
7	OTPC	1	-	-	-	-	-	-	-	-	-	-	-
8	NTPC	1	-	-	-	-	-	-	-	-	-	-	-
9	NAGALAND	1	3	1	3	100.0%	100.0%	-	-	-	-	100.0%	100.0%
10	MIZORAM	2	4	2	3	100.0%	75.0%	-	1	-	25.0%	100.0%	100.0%
11	MANIPUR	-	11	-	6	-	54.5%	-	2	-	18.2%	-	72.7%
12	Ar.Pradesh	-	9	-	9	-	100.0%	-	-	-	-	-	100.0%
	TOTAL	26	150	3	21	11.5%	14.0%	13	94	50.0%	62.7%	61.5%	76.7%
	Total (over all)	176		24		13.6%		107		60.8%		74.4%	

Note:
1. Constituents-wise details as per data available atNERLDC
2. 'GS' Generating Stations and 'SS' sub-Stations
3. Status considered above are grid sub-station and upto 66 KV voltage level.
4. Partial data available means if any part of the elements like Bus-Voltage/frequency/analog/degital/reactors is under suspect condition/not 100%.

4.12.2 It is observed that data availability for all the substations and generating stations is not there and the work is in progress. Hence actual scenario at 110 kV level above base case of Poc for every timeblock is not possible with current telemetry without making assumptions of nodal data.

4.12.3 The Taskforce observes that RLDCs have actual data for all the ISTS interface points with States which may be at 765kV, 400kV,220kV or 132 kV since actual ISTS drawal / injection is being measured and billed under Deviation settlement mechanism and regional transmission deviation account. The purpose of the entire exercise is to allocate ISTS charges on entities using ISTS. However data for intra-state points are required for simulation of the network. The model may be simulated such that drawal/injection ISTS is as per actual All India peak. For load generation balance necessary adjustments may be made. Hence calculation on actual scenario is possible on 15 minute blockwise basis as far as availability of data is concerned.

4.12.4 There may be issues in online availability of real time data due to communication issues in Powergrid/ Posoco system / system down . We observe that realtime data is not required for transmission charges allocation which requires data post fact. This ISTS drawal /injection data is already being compiled by RLDCs and provided to RPCs in about a weeks time after end of the month. POC charges can be calculated for the month by end of the 2nd month for 1st month and can be billed in beginning of 3rd month.

4.12.5 Before dealing with TOR 5 in which modifications required in existing mechanism is to be suggested, we are dealing with TOR 6 in which discussions with respect to reliability charge and HVDC charge is to be made. These components forms part of TOR 5 recommendations.

TOR 6: Specify reliability benefit in a large connected grid and provide methodology for determination of quantum of Reliability Support Charges and its Sharing by constituents and to provide Methodology of Sharing of HVDC Charges by constituents;

4.13 What should be reliability charge?

4.13.1 Mr. Vijay Menghani, CEA has suggested as follows:

(a) While approving 10% reliability charges in POC mechanism, CERC vide its SOR instructed implementing agency POSOCO to formulate, within six month, detail methodology for computing how much charges for reliability should be charged to DICs. This is yet to be completed.

(b) The detailed technical literature survey has been made in regards to method of allocation of reliability charges and a numerical value for reliability.

(c) It is important to note the reliability for each node in transmission system is different in a particular load scenario and also if scenario is changed, the value again changes. It is measured under two parameters i.e frequency of disruption and load affected or energy not served. Searching a common value of Reliability for complete transmission system and declaring it through a Tariff Policy as suggested by Advisor Posoco is a never ending exercise as it has not been done anywhere in world. Also the value of reliability is different for different consumers / DICs based on its Value of Load loss (VOLL) , which it self is a big debatable academic issue as it depends on category of consumer. For DIC importing from ISTS value of reliability is different than that for a self-sufficient State.

(d) The reliability based allocation of transmission charges are in vogue since 1998 and technical papers are more or less recommending same methodology and IIT Mumbai is also proposing the same. Under this for each node importance of a transmission line is assessed by opening that line and computing Line loss factor. This is a separate exercise of load flow under contingency. As already POC method is considered complicated, this further computation would result in making it more complex, so it is suggested that this may not be required at this stage.

(e) So the question arises, how reliability should be charged. For answer of this question we may need to go back to transmission planning process. During transmission planning of ATS of a generating station and system strengthening scheme for a regional network, how reliability is ensured. This is not a numerical input of say 20% or 25% reliability is put into planning software and it suggest some transmission line. New proposed system is superimposed on existing system and following is checked for six scenarios as given in planning criteria:

a. Lines are not overloaded.
b. Voltage at different nodes are within limits
c. N-1 criteria is satisfied for different operating condition and system remain stable after outage of elements

(f) How this is achieved, it is achieved through inherent margins in the existing and proposed system which is coming through Lumpy nature of transmission investment, which is now being cursed as "unutilised Capacity". By ensuring stable power supply in all part of the meshed grid a reliability is ensured and the system operator during real time operation follows the limits and margin of system in operation.

(g) So without prescribing a numerical value a really valuable service of reliability is provided to users by ensuring power supply during all conditions especially during Peak hours . So if power supply during Peak hours is ensured, ultimately the margins of transmission system are being utilised and if at this time some contingency happened and still supply is not affected, reliability is delivered.

(h) So peak scenario is itself a proxy to reliability and if states are paying for Peak scenario, then there is effectively no need of paying reliability charges separately. As suggested earlier, under weighted average of Peak and off peak scenario DICs would pay both for flows and margin available in system so effectively reliability would be paid.

(i) The proposal of IIT ,Mumbai for considering only Flow as use and trying to recover balance system cost through some other method would be technically incorrect and problematic . This balance system is not lying un- utilised, this is providing reliability service .

(j) Suggestion: The separate value or a number can not be assigned for reliability of whole ISTS and charge can not be recovered on the basis of that . If reliability cost is to be allocated it would be line wise and user wise allocation which is complex.

4.13.2 During the meetings of taskforce Professor Abhyankar has proposed a methodology to determine reliability benefit. He stated that he has extensively researched international papers and that almost all papers propose Embedded Cost = Capacity Use + Reliability Charge. Roy Billinton, in his epic book mentions that'System Reliability' has two components:

'System Adequacy' and 'System Security'

Question: What is each transmissionelements' contribution in 'systemadequacy'when 'system security' is under threat?

Question: How the absence of an elementaffects the state variables and hence the basecase flow condition?

4.13.3 Prof. Abhyankar proposed two methods are proposed: Method 1 & Method 2 based on:

(a) The impact of transmission element outage on other elements (N-1).

(b) Providing appropriate weight to line outage condition, depending on voltage level.

(c) Both the methods need running of multiple power flows.

(d) Linear dependency of voltage level of line is considered.

POC data of Indian grid consists of 765 kV, 400 kV, 220 kV and 132 kV. The weights (wk) considered for these lines are 1, 0.75, 0.5 and 0.25, respectively.

Method 1

- Obtain base case steady state solution
- For each outage line '*k*', run power flow and get line flows. $l \in L \neq k$
- Calculate Y for all lines

$$Y_k^l = \left\{ \frac{\max\{|P_l^k| - |P_l^0|, 0\}}{\overline{P_l}} \right\} \forall l \in L \neq k$$

$$Y_k = \max\{Y_k^l\} \forall k$$

$$Y_k^{final} = Y_k w_k \forall k$$

$$Y_k^{Cost} = C_k \times Y_k w_k \forall k$$

A. R. Abhyankar, IIT Delhi

For line *k*,

$Y_k^{final} \times 100$ is the percentage of total embedded cost th should be marked as reliability charge

Total Reliability Charge (Y) for the system is

$$Y = \sum_{\forall k} Y_k^{Cost}$$ Flat Rate

$$X = Z - Y$$ Hybrid Method

Method 2:

- For each outage line '*k*', run power flow and get line flows.
- Calculate Y for all line $l \in L \neq k$

$Y_k^{Cost} = C_k \times Y_k w_k \forall k$

$$Y_k^l = \left\{ w_k \left(\frac{\max\{|P_l^k| - |P_l^0|, 0\}}{\overline{P_l}} \right) \right\} \forall l \in L \neq k$$

$$Y_k^{final} = \max\{Y_k^l\} \forall k$$

$$Y_k^{Cost} = C_k \times Y_k^{final} \forall k$$

For line *k*,

$Y_k^{final} \times 100$ is the percentage of total embedded cost that should be marked as reliability charge

Total Reliability Charge (Y) for the system is

$$Y = \sum_{\forall k} Y_k^{Cost}$$

Flat Rate

$$X = Z - Y$$

Hybrid Method

The simulation results are as below:

	765 kV	400 kV	220 kV	132 kV
Method 1	18.84%	8.34%	6.42%	4.15%
Method 2	18.84%	11.12%	12.84%	15.63%

4.13.4 Professor Soman also suggested a methodology to determine reliability component as follows:

- The increased line power flows are computed using the line outage distribution factors (LODF) for the N-1 contingency conditions.
- The difference between the maximum power, thus found, and the base case line flow in that line is the reliability capacity of that line.

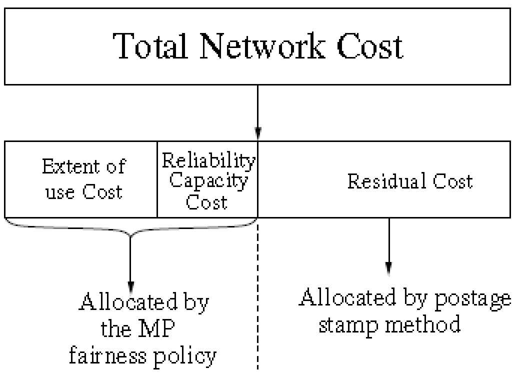


FIGURE: Block diagram of cost causal MP approach with reliability cost

4.13.5 He shared the results on a sample system as follows:

TABLE: Summary of *NetEOUCost* and *NetRelCapCost* percentage of TSU^0 for the proposed method

IEEE Network	%*NetEOUCost*	N-1 contingency based %*NetRelCapCost*
14-Bus	26.63	6.89
30-Bus	43.75	11.46
57-Bus	21.93	7.85
118-Bus	33.14	11.56

4.13.6 CERC had introduced the concept of in view of the fact that DICs getting benefits which accrue to them by virtue of operating in an integrated grid. The Statement of Reasons for 3rd amendment provides as follows:

"The Commission has for the present taken a decision to allocate 10% charges as Reliability Support Charges. However the Commission would like to have a better picture in this regard and hence has directed POSOCO to prepare a base paper in consultation with CEA and CTU on quantification of reliability benefit in a large inter-connected grid such as ours including market risk mitigation based on international experience.

13.23 In view of the foregoing discussions, the concept of common benefit of Reliability needs to be introduced in the mechanism for sharing of transmission charges. We agree with POSOCO that all the entities, be it a generator or load serving entity, are availing reliability support of the grid. We are of the view that any user who is connected to the Grid gets access to improved power quality, enhanced reliability and stabilized operation. The interconnected system (Electricity Grid as a whole) gives stability and provides inertia. Transmission system is a common carrier and every entity (whether an injecting or drawing utility) having connectivity to the transmission system avails its services.

13.24 An operating generator, when it gets connected to a larger system would get the advantage of better frequency control, better reactive power management and voltage control, quick availability of startup power supply in case of a blackout at the power station and so on as compared to a situation wherein it was operating in islanded mode. Similarly, Drawee Entities / Discoms also get benefitted by way of improved frequency and voltage profile, improved adequacy and reliability. The Drawee Entities can source their requirements for power from various generators either to get benefit of cheaper power or to avail supply/assistance during emergencies. The consumers in turn benefit by way of improvement in quality and quantity of supply. For instance, by installation of polymer insulators in place of porcelain insulators in the Northern Region, not only the reliability of Northern Region Grid has improved but also that of other inter connected regional grids in the country benefited, which would have otherwise been vulnerable due to tripping of a large number of transmission lines in NR during heavy fog conditions. Further there is an increasing use of Power Electronic Devices (PEDs) such as High Voltage Direct Current (HVDC) systems, Static Var Compensators (SVCs), STATCOMs, Thyristor Controlled Series Capacitor (TCSC) in the system. The controllability of these devices makes them helpful in case of an emergency in the power system. All players connected to the grid avail benefit of these devices through better grid security. Therefore, the DICs (generator or load serving entity) need to pay certain transmission charges.

13.25 We would like to make it clear that we had proposed dispensing with uniform charges on the premise that the basic philosophy of Sharing Regulations is that sharing of transmission charges needs to be related to quantum of flow and it would be just and appropriate to dispense with uniform charge which is based on LTA or deemed LTA based on allocation of power from Central Sector Generating Stations. However we find merit in considering a part of charges of ISTS as Reliability Support Charges in view of reliability benefits which accrue to users of Grid (DICs) by virtue of operating in an integrated grid. Hence irrespective of location of the user and quantum of payment of transmission charges based on the actual usage, every user needs to pay certain fixed charges corresponding to their Approved Injection or Approved Withdrawal, as the case may be. 13.26 Hence to start with we decide that 10 % of the yearly transmission charge for AC system is to be recovered through Reliability Support Charge. Similarly, 10% of the transmission charge for HVDC systems (including Back-to-Back system) except where the transmission charges for any HVDC system which are to be partly borne by a DIC under a PPA, shall be considered under Reliability Support Charge. The same may be revised as and when considered necessary by the Commission. These charges are to be paid by DICs as a part of transmission charges corresponding to their Approved Injection or Approved Withdrawl. While Commission has for the present taken a decision to allocate 10% charges as Reliability Support Charges, the Commission would like to have a better picture in this regard. We therefore, direct POSOCO in consultation with CEA and CTU to prepare a base paper on quantification of reliability benefit in a large inter- connected grid such as ours including market risk mitigation based on international experience and submit for consideration of the Commission."

4.13.7 Recommendations of taskforce for reliability charge

(a) We have persued international literature on calculation of reliability charge w.r.t transmission cost allocations. A list of such papers is enclosed at Annexure to the report. A few papers have taken capacity left unused as reliability. A few papers calculate reliability component by switching off the line and assessing its impact on the system.

(b) We observe that reliability benefits calculations are proposed as following in IEEE paper "Consideration of the Reliability Benefits in Pricing Transmission Services" by Hyungchul Kim and Prof Channan Singh:

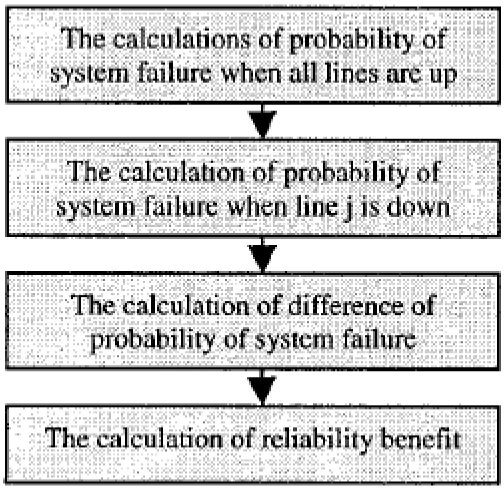


Fig. 1 Flow chart for the reliability benefits calculation

(c) We observe that few components of power system such as reactors, SVCs, Statcoms, back to back HVDC, spare transformers, spare reactors can be considered as providing reliability to the overall system.

(d) The Reliability Criteria as per CEA Transmission Planning Criteria 2013 is provided as below:

"**6. Reliability criteria**
6.1 Criteria for system with no contingency ('N-0')
a) The system shall be tested for all the load-generation scenarios as given in this document at Paragraph: 9 -11.
b) For the planning purpose all the equipments shall remain within their normal thermal loadings and voltage ratings.
c) The angular separation between adjacent buses shall not exceed 30 degree.

6.2 Criteria for single contingency ('N-1')

6.2.1 Steady-state :

a) All the equipments in the transmission system shall remain within their normal thermal and voltage ratings after a disturbance involving loss of any one of the following elements (called single contingency or 'N-1' condition), but without load shedding / rescheduling of generation: - Outage of a 132kV or 110kV single circuit, - Outage of a 220kV or 230kV single circuit, - Outage of a 400kV single circuit, - Outage of a 400kV single circuit with fixed series capacitor(FSC), - Outage of an Inter-Connecting Transformer(ICT), - Outage of a 765kV single circuit - Outage of one pole of HVDC bipole.

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

6.2.2 Transient-state : Usually, perturbation causes a transient that is oscillatory in nature, but if the system is stable the oscillations will be damped. The system is said to be stable in which synchronous machines, when perturbed, will either return to their original state if there is no change in exchange of power or will acquire new state asymptotically without losing synchronism. The transmission system shall be stable after it is subjected to one of the following disturbances:

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

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

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

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

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

f) The system shall be able to survive a fault in HVDC convertor station, resulting in permanent outage of one of the poles of HVDC Bipole.

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

6.3 Criteria for second contingency ('N-1-1')

6.3.1 Under the scenario where a contingency as defined at Paragraph: 6.2 has already happened, the system may be subjected to one of the following subsequent contingencies (called 'N-1-1' condition):

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

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

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

6.3.2 (a) In the 'N-1-1' contingency condition as stated above, if there is a temporary fault, the system shall not loose the second element after clearing of fault but shall successfully survive the disturbance.

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

6.4 Criteria for generation radially connected with the grid

For the transmission system connecting generators or a group of generators radially with the grid, the following criteria shall apply:

6.4.1 The radial system shall meet 'N-1' reliability criteria as given at Paragraph: 6.2 for both the steady-state as well as transient-state. 6.4.2 For subsequent contingency i.e. 'N-1-1' (of Paragraph: 6.3) only temporary fault shall be considered for the radial system.

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

(e) It is observed that reliability is related primarily to (N-1) condition such that system should survive under this contingency. Accordingly we have proposed a methodology to calculate reliability benefit for each line under modified PoC method. Under Uniform charges method since all charges are socialised, there is no need to calculate separate reliability charge. Under modified PoC method following methodology may be adopted for calculating reliability benefit:

(a) The base case shall be prepared as per last month's actual All India peak.Contingency of n-1 should be simulated for all lines one by one. The flows in all lines in this contingency should be captured. Such contingencies should be created for all the lines and flows be captured.

-An illustration is shown below for 5 lines in the network

Table 21: Illustration for simulating N-1 for reliability component calculations

Line No.	**Base case flow PB (MW)**	**Base case flow with Contigency 1 P1 (MW)**	**Base case flow with Contigency 2 P2 (MW)**	**Base case flow with Contigency 3 P3 (MW)**	**Base case flow with Contigency 4 P4 (MW)**	**Base case flow with Contigency 5 P5 (MW)**	**Maximum flow in line considering Contingencies Pmax (MW)**	**PR= Pmax-PB (MW)**
1	500	Line 1 out	600	700	100	500	700	200
2	400	500	Line 2 out	200	100	300	500	100
3	300	200	400	Line 3 out	700	200	700	400

Line No.	**Base case flow PB (MW)**	**Base case flow with Contigency 1 P1 (MW)**	**Base case flow with Contigency 2 P2 (MW)**	**Base case flow with Contigency 3 P3 (MW)**	**Base case flow with Contigency 4 P4 (MW)**	**Base case flow with Contigency 5 P5 (MW)**	**Maximum flow in line considering Contingencies Pmax (MW)**	**PR= Pmax-PB (MW)**
4	200	300	500	100	Line 4 out	600	600	400
5	700	600	200	800	300	Line 5 out	800	100

In the above example PR represents reliability component of each line. PR is to be dividied by loadability of the line to determine % of cost of such line to be considered under reliability component.

(b) The Reliability component of each line shall be calculated and added for the entire network to determine total reliability charges.

(c) These charges should be shared among entities in ratio of their peak ISTS drawal/injection for the month. For example reliability charge to be shared is Rs. 100 crore for the month and there are 5 entities in the grid and peak ISTS drawal for June 2019 is as detailed below.

Table 22: Illustration for Sharing of reliability charges

Entity	Peak ISTS drawal /injection for the month (-ve represents injection) (MW)	Date/time of ISTS drawal	Reliability charge sharing (Rs. Crore)
A	500	15 June, 26th time block	100X500/2900
B	-600	10 June, 46th time block	100X600/2900

Entity	Peak ISTS drawal /injection for the month (-ve represents injection) (MW)	Date/time of ISTS drawal	Reliability charge sharing (Rs. Crore)
C	-800	1 June, 85th time block	100X800/2900
D	1000	21 June, 7th time block	100X1000/2900
Total	2900 MW		

(d) The reliability component shall be shared in proportion to its peak ISTS drawal /injection irrespective of day and time for such drawal/injection i.e noncincident peak for each entity for the last month. For generators it should be shared in proportion to its untied LTA. i.e the entire reliability charge is suppose Rs. 'P'. Rs. 'P' should be divided by sum of non-coincident peak ISTS drawal or injection + untied LTA of generators to get reliability rate in Rs./MW/month. This rate should be multiplied by noncoincident peak ISTS drawal/injection for States and by untied LTA for generators to determine their reliability bill component.

4.14 Treatment of HVDC Charges

4.14.1 Some of the stakeholders have suggested that transmission charges for HVDC system should be socialized. Whereas some of the stakeholders have suggested that HVDC charges should be paid by withdrawing DICS. Some stakeholders have suggested that HVDC charges should also be determined for STOA customers in line with LTA/MTOA customers.

4.14.2 POSOCO has suggested following with regards to HVDC:

(a) HVDC assets are for benefit of the country as a whole and attributing usage to particular beneficiaries may not be appropriate.

- Bi-directional power flow through HVDC links
  - Power flow through Mundra - Mahendragarh and/or Talcher-Kolar HVDCs are modulated in both the directions to control flow through parallel AC system.
  - Further, HVDC allows operators to quickly change the direction of power flow, which makes it suitable for connecting wind, solar and other renewable sources.
- Reliability Benefits
  - HVDC lines help in voltage control, relieving loading of intervening AC network and enhancing power transfer capability, thereby improving reliability of the grid.
- Flexibility for Renewable Integration
  - Renewable energy such as wind and solar are increasing their penetration in the Indian Electricity market and it is expected that an increased percentage of total power consumption and/or generation would come from renewable energy sources. The optimal locations for these renewable energy sources are found in remote or offshore locations that are long distances away from load centres. Therefore, the generated power from these remote renewable energy sources must be transmitted to the urban areas for consumption and whenever power has to be

transmitted over long distances, DC transmission is the most economical solution compared to high-voltage AC.

- HVDC also can connect AC grids to renewable sources while improving power quality, stability and reliability on those networks by reducing disturbances. The networks can be managed by control centres while operators keep the grid balanced by injecting the necessary power when there is a dip or peak in demand.

(b) In the past, states had expressed reservation to termination of new HVDC lines in their state in view of apprehension that it would have impact on PoC rates. Thus optimal development of power sector in the country with a proper mix on AC/HVDC lines would be hampered. In a country with high growth, more such assets may be required for transferring bulk power to load centres and for accommodating renewables.

(c) In view of above, it is suggested that charges of HVDC lines may be socialized amongst all DICs. In fact, the Hon'ble Commission had initially notified node wise apportionment of HVDC charges (depending on which nodes are benefitted most on account of HVDC) w.e.f. July, 2011 but subsequently changed over to socializing the same w.e.f. April, 2014. However, the third amendment followed by separate treatment for sharing of BNC-Agra, Champa-Kurukshetra and Mundra-Mohindergarh, HVDC charges has resulted in uncertainty over future HVDC charges sharing. Considering the upcoming HVDCs, Raigarh-Pugalur and Pugalur

– Thrissur which have bidirectional features (required under high RE scenario when substantial exports are expected from Southern Region), the Commission may consider to socialize the same.`

4.14.3 **CTU has suggested following with respect to HVDC.**

(a) Need for review of sharing of transmission charges for HVDC systems

In last 8 years, Indian Power sector and transmission grid has gone through radical transformation. The NEW grid and SR grid have been synchronized on 31st December, 2013 and Indian grid it has become one of the world's largest interconnected grids. With increasing size and complexities of the grid, which include change in generation mix due to higher participation of RE, increasing customer expectations for reliability and resilience, increasing role of power market in meeting the Discom's power supply requirement, role and need for HVDC systems in India has increased significantly. CERC and MoP have also underlined the importance of HVDC links while declaring NER-Agra HVDC link as an Asset of strategic and National importance.

(b) Further, The Government of India has established an ambitious target of 175 GW RE by 2022 that includes 60 GW of wind and 100 GW of solar. Over the past few years, the share of renewable capacity in the India has increased from 12% in 2012 to over 18% in 2017. Going forward, with renewable power achieving grid parity or even becoming cheaper than conventional power and technological advancements across the eco-system, the renewable generation is staged to play a bigger and a deeper role in the country's energy mix. Between 2017 and 2030, the share of renewable generation is expected to reach over 43% in capacity terms.

(c) Higher the penetration of renewable generation, higher will be the requirement of load following generating stations to manage the system. However, under a high renewable rich scenario, the balancing of the grid through the conventional load following generating stations such as hydroelectric plant and gas based thermal plant would not be adequate. In view of the need of integration of target renewable generation, some conventional generation units may be required to operate at their minimum operating levels and cycle up and down more frequently to accommodate the variable and intermittent renewable generation in the system. In the report, ―Flexibility requirement in Indian Power System, NLDC, January 2016‖, following is stated:

Quote:

Power *produced by renewable like solar and wind continues to grow,* ***the grid will see larger swings in total generation****. Fast ramping power plants, which have enough flexibility, are a good option to have in the system*.

Unquote:

If solar generators do not generate reactive power, then reactive power support is required across the grid, during the high solar penetration period. Thus, in line with the contemporary scenario of increasing penetration of RE , associated issues with RE integration and importance of HVDC bi-Pole links in maintaining stability and reliability for National grid, The sharing of HVDC charges for HVDC Bi-polar links needs to be revisited.

(d) **Benefits of HVDC:**

i. Benefits associated with long distance HVDC transmission projects are availed by beneficiaries spread geographically across multiple utility service areas and states. The major benefits include renewable integration, increased reliability, decreased transmission congestion, reduced losses, reduced generation resource requirements, increased competition in power markets etc.

ii. Although HVDC transmission is a fairly mature technology globally, recent technological improvements have expanded its capabilities and applicability for addressing grid challenges. HVDC has the unique capability to connect asynchronous grids which has been utilized immensely by India during pre-National Grid period. HVDC bi-pole lines provide control opportunities, many of which have been utilized for several decades and for which there is significant operating experience. HVDC provides for multiple controls in the grid. Steady-state control can be imposed by simply changing the flow on the HVDC line. It can be useful to do this in order to relieve congestion elsewhere in the network. Power Regulation in the grid may be obtained by using the DC line to follow part or all of the MW variability in one control area to ship to another control area. This can be particularly useful when there is high penetration of variable generation in one area and available fast-ramping generation in another area. HVDC may also be used to mitigate voltage instability, to increase damping of inter area oscillatory modes, to enhance transient stability performance, and to control sub synchronous resonance.

iii. HVDC links function as a pseudo phase-shifter and help in mitigating oscillations in inter-area mode and above all, the frequency controllers at HVDC stations help in operation of regional transmission system, if it were to get islanded due to any reason.

iv. Thus, HVDC technology provides extremely rapid stability control, power flow control, and the ability to segment parts of the power system—all of which can enhance the grid's flexibility, reliability and resilience. Bi-directional HVDC technology enables optimal hydro-thermal mix of all the regional grids due to its connectivity with the hydro surplus Region on one end and thermal surplus regions on the other end. In post-National Grid period, these attributes of HVDC have becomes extremely critical and further, in view of RE integration, said benefits have become a pre-requisite requirement for large Indian grid which completely changes the context in which utilization of HVDC bi-pole links have been analysed till recently. After RE integration, HVDC transmission system would provide flexibility by providing benefits through reduction of the need for cycling fossil fuel power plants by spreading the impact of intermittent generation across a wider geographic region. Further, it will facilitate in power balancing for grid support and smooth integration of large scale renewable generation. To conserve on the reactive power support needed, implementation of more HVDC links will be helpful. Also, there are inverters that can generate local voltage support also. Thus considering the intermittent nature of RE, these attributes of HVDC links will be required in enabling smooth RE integration in Grid.

v. Further, HVDC links provides safeguard against extreme events such as multiple or sustained generation and transmission outages. Although extreme events occur very infrequently, but when they occur they can significantly reduce the reliability of the system, induce load shed events, and impose high emergency power costs. The investment to be made in additional transmission in reducing the impact of extreme events can be significant, despite the relatively low likelihood of occurrence. While the value of increased system flexibility during extreme contingencies is difficult to estimate, system operators intrinsically know that increased system flexibility provides significant value.

vi. Besides above benefits, HVDC Bi-pole links provides flexibility to grid operators to provide margins in parallel AC networks. These margins are being utilized for STOA and MTOA thus increasing the liquidity in the market.

(e) Keeping above in view, it can be seen that HVDC assets provide benefit to the country as a whole and attributing its usage to select beneficiaries may not be appropriate.

(f) Sharing of HVDC Charges:

i. As elaborated above, it may be difficult to quantify specific beneficiaries and extent of service extended by HVDC links to them. Such benefits are availed nationally for complete grid and with pan India one grid; such benefits cannot be valued locally or individually. Therefore as the importance of HVDC link at national level is established, ultimately during cost allocation analyses, utilization and requirement of HVDC link can be looked from national grid's perspective only instead of looking from individual beneficiary's perspective.

ii. As inherently HVDC links involves large capital investment, YTC for the same is also high. Continuing with cost allocation/sharing of some bi-pole HVDC links to DIC's of beneficiary regions as identified during planning stage will hamper the growth of HVDC system in country as no beneficiary would want to burden themselves with high cost of HVDC links. Considering the importance of HVDC bi-polar links for safe and secure operation of the grid, it is essential that the cost of all HVDC system be socialized among all beneficiaries as the benefits are availed among all grid participants.

4.14.4 CEA has suggested following with regards to sharing of HVDC charges:

(a) The Third Amendment to the Sharing of inter-State Transmission Charges and Losses) dated the 1st April 2015 provides that 10% of Monthly Transmission

Charges (MTC) of HVDC transmission system shall form part of Reliability Support Charges and balance transmission charges for HVDC system shall be borne by DICs of specific regions for whom the HVDC system was created. The HVDC Charge are payable by DICs of the Region in proportion to their Approved Withdrawal. In case of Injection DICs having Long Term Access to target region, it is payable in proportion to their Approved Injection.

(b) With regard to sharing of transmission charges for HVDC system, CEA is of the view that transmission charges for the HVDC system should be borne by the DICs for which the HVDC system was planned / DICs getting benefit from the HVDC system.

(c) Accordingly the transmission charges for the following HVDC transmission lines and HVDC Back to Back may be shared as give below:.

Table 23: CEA recommendation on sharing of HVDC charges

S. No.	Name of HVDC	Name of Region / state / utility for Sharing of transmission charge
1	Rihand-Dadri +500kV HVDC Bipole	Northern Region constituents
2.	Talcher-Kolar +500kV HVDC Bipole	Southern Region Constituents
3.	Ballia – Bhiwadi +500kV HVDC Bipole	Northern Region constituents
4.	Mundra – Mahendragarh + 500kV HVDC bipole line	1495 MW Adani Power Ltd. & for 1005 MW Northern Region constituents
5.	Bishwanath Chariyali–Agra +800kV, HVDC bipole.	Northern Region constituents
6.	Champa-Kurukshetra +800kV HVDC bipole	Northern Region constituents & IPPs in Chhattisgarh
7.	Raigarh-Pugalur +800kV HVDC bipole	Southern Region Constituents
8.	Pugalur- North Thrissur ±320 kV HVDC	Kerala
9.	Gazuwaka HVDC back to back	Eastern Region & Southern Region Constituents
10.	Sasaram HVDC back to back	Eastern Region & Northern

S. No.	Name of HVDC	Name of Region / state / utility for Sharing of transmission charge
		Region Constituents
11.	Vindhyachal HVDC back to back	Northern Region & Western Region Constituents
12.	Chandrapur HVDC back to back	Western Region & Southern Region Constituents

4.14.5 Some stakeholders have stated that HVDC rates for MTOA and STOA customer should be in line with the LTA of customer

4.14.6 **Analysis and Recommendations of the Taskforce**

(a) The mechanism in vogue for sharing of HVDC charges was deliberated in 3rd amendment issued dated 4.4.205. The Statement of reasons are quoted below:

"

45.2 Comments have been received from POSOCO and CEA.

45.3 POSOCO has suggested that, if charges of HVDC are apportioned to nodes which get benefitted because of presence of HVDC, then there would be opposition from the States to termination of HVDC lines in respective States. There is substantial impact of set point of HVDC (direction and quantum of power flow) considered in base case on nodal charges. Thus, the assumptions would be questioned by stakeholders affected. A 800kV 6000 MW multi-terminal HVDC link from Biswanath Chariali/ Alipurdwar to Agra is under construction. If charges are shared based on usage, PoC rates nodes nearer to the stations like NER / ER States may be affected. Further, POSOCO has emphasized that since HVDC systems are national assets, the existing provision may be retained.

45.4 CEA has stated that, in the present methodology, the impact of PoC rate on account of HVDC bi-pole/multi-terminal/back-to-back links is being determined through a 'with and without' methodology in marginal participation algorithm. CEA has suggested that instead of 'with and without' methodology for HVDC, the power order on the HVDC link, as given in the base case under consideration, may be reduced by 1% to account for the impact of cost of HVDC on PoC rates of various nodes. This methodology would be in line with basic principle of marginal participation i.e. to have a small perturbation.

45.5 POSOCO has suggested to continue with existing philosophy of socializing the cost of HVDC system whereas CEA has suggested a modified With & Without methodology. After the notification of Sharing Regulations, a technical study was conducted by IIT Bombay, which also included the method now suggested by CEA. The extracts from the views expressed by IIT, Bombay are given below:

"A Study on Alternatives for Cost Allocation of HVDC Lines with Reference to Central Electricity Regulatory Commission (Sharing of Inter State Transmission Charges and Losses) Regulations, 2010 was conducted by Prof. S A Soman, Power Anser Labs Department of Electrical Engineering, IIT, Bombay during Feb, 2011 on the request of CEA. However the method as suggested by CEA of changing power order was not found suitable".

45.6 We intend to recapitulate the issue of allocation of cost of HVDC from the beginning.

45.6.1 "With and Without" HVDC method provision was made in the Sharing Regulations notified in June, 2010 as under:

"2.7 COMPUTATION: DETERMINATION OF SHARING OF YTC AND TRANSMISSION LOSSES

The simulations will be carried out by the IA by using software duly approved by the CERC. The following steps shall be followed:

1. Converged AC Load Flow data for the NEW Grid and the SR Grid for the truncated network shall be used directly for the implementation of the Hybrid method.
2. Treatment of HVDC lines: Flow on the HVDC line is regulated by power order and hence it remains constant for marginal change in load or generation. Hence, marginal participation of a HVDC line is zero. Thus, MP-method cannot directly recover cost of a HVDC line. Therefore, to evaluate utility of HVDC line for a load or a generator, the following methodology shall be applied:

   Step 1: Evaluate the Transmission System charges (of AC network) for all loads and generators corresponding to base case which has all HVDC lines in service.

Step 2: Disconnect the HVDC line and again compute the new flows on the AC system. Hence, evaluate the new transmission system charges (of AC network) for all the loads and generators.

Step 3: Compute the difference between the Nodal Charges (unit- Rs) with and without HVDC line and identify nodes which benefit from the presence of the HVDC lines. Benefit is new (with disconnection) usage cost minus old (with HVDC) cost. If benefit is negative, it is set to zero.

Step 4: The cost of the HVDC line is then allocated to the nodes in proportion of the benefits they derive from its presence as computed above. **In the case of SR Grid, which is not synchronously connected with the NEW grid, the 'benefits' shall be computed at nodes which were indicated to have higher transmission usage costs attributed to them 'without' the HVDC line (Talcher-Kolar).** When Talcher-Kolar link is disconnected**, the loads in the SR are reduced proportionately such that net reduction is equal to the power received from the Talcher-Kolar link**. Then, new usage costs are worked out. Benefit herein is defined as old cost **(base case with injection from Talcher-Kolar**) minus new usage cost i.e. with link disconnected if any.

HVDC line can be modeled as a load with MW equal to P-order at the sending end and a generator with corresponding MW at the receiving end. A 'without' scenario for a HVDC line, corresponds to disconnecting the corresponding load-generation pair. Sensitivities for these fictitious loads and generators are not computed as they are not to be priced.

45.6.2 However, KPTCL had brought out disadvantages of With and Without method to the State in which the terminals are connected, and same was explained in the Explanatory Memorandum of the draft second amendment as under:

Quote:

1.3 Subsequently, some further difficulties were either pointed out by others or noted by the staff of the Commission. M/s LANCO pointed out that the Point of Connection (PoC)

injection rate (in `/MW/month) for its generating station in the State of Andhra Pradesh was coming unreasonably high, as the PoC injection rate was obtained by dividing the injection PoC charge of the zone by the total long-term access (LTA) of the State and LANCO was the only ISGS in Andhra Pradesh with LTA. It is observed that this would happen when a State has inter-State generating stations with small quantum of LTA connected to the 400 kV systems in any State. There is, therefore a need to remove this anomaly. **Further, Karnataka Power Transmission Corporation Ltd. (KPTCL) pointed out that while adopting the methodology as given in the Sharing Regulations, around 45% of the Yearly Transmission Charges (YTC) of the Talcher – Kolar HVDC bi-**

pole links was being booked to the State of Karnataka, whereas the allocation of power to the State from Talcher – II STPS, for which the HVDC bi-pole link was built to evacuate this power to the constituents of Southern Region, was only 18.86%.

6.0 ISSUE OF SHARING OF TRANSMISSION CHARGES OF TALCHER-KOLAR

HVDC BI-POLAR LINK

6.1 Step 4 of para 2.7 of Annexure to the principal regulations is reproduced as below:

> "Step 4: The cost of the HVDC line is then allocated to the nodes in proportion of the benefits they derive from its presence as computed above. In the case of SR Grid, which is not synchronously connected with the NEW grid, the 'benefits' shall be computed at nodes which were indicated to have higher transmission usage costs attributed to them 'without' the Talcher-Kolar HVDC line. **When Talcher-Kolar HVDC link is disconnected, the loads in the SR are reduced proportionately such that net reduction is equal to the power received from the Talcher-Kolar link**. Then, new usage costs are worked out. Benefit herein is defined as old cost (base case with power received from Talcher–Kolar HVDC link) minus new usage cost i.e. with link disconnected. If any HVDC line can be modeled as a load with MW equal to P-order at the sending end and a generator with corresponding MW at the receiving end. A 'without' scenario for a HVDC line, corresponds to disconnecting the corresponding load-generation pair. Sensitivities for these fictitious loads and generators are not computed as they are not to be priced."

It is observed that the transmission charges for the Talcher-Kolar HVDC line are to be borne by the constituents of the Southern Region. It is seen, however, that this method of transmission charge allocation, loads the transmission charges of Talcher-Kolar HVDC line to the extent of approximately 45% on the State of Karnataka, since this HVDC line terminates in Karnataka (Kolar). Before the Sharing Regulations came into force, the charges of **Talcher-Kolar HVDC line were being borne by the Southern Region constituents in the ratio of the allocation of power from Central Generating Stations of the Southern Region and Eastern Region**.

Moreover, it is seen that for transmission of power from NEW grid to SR grid, other than for evacuation of power from Talcher Stage - II generating station, there are only three HVDC links i.e., HVDC back-to-back links at Gazuwaka and Chandrapur and the Talcher-Kolar HVDC bi-polar link. For **Gazuwaka back-to-back HVDC link and Chandrapur back-to-back HVDC link, the charges are shared in the ratio of 1:1 as** given in the

Central Electricity Regulatory Commission (Sharing of inter-State Transmission Charges and Losses) (First Amendment) Regulations, 2011. For Talcher-Kolar HVDC line, it is mentioned that that the charges shall be shared by the DICs of SR. The same is reproduced below:

> "The charges of the HVDC back to back inter-regional links at Chandrapur and Gazuwaka shall be included in the YTC of the **NEW grid and the SR grid in the ratio of 1:1 and charges** for Talcher–Kolar HVDC bi-pole link shall be shared by DICs of SR only."

6.2 The methodology for the sharing of charges of Gazuwaka back-to-back HVDC link and Chandrapur back-to-back HVDC link is to increase the YTC of the NEW grid and SR grid in 1:1. However, the **methodology for the sharing of charges of Talcher-Kolar HVDC bi pole link, as is given in the Sharing Regulations, is being done based on the difference of PoC charge between injection of Talcher Stage-II generating station at Kolar (Karnataka) end and without that injection, as provided in the Sharing Regulations.**

In view of the above, the sharing of charges of Talcher-Kolar HVDC bi pole link should be done in the same way, as is being done for the HVDC back-to-back links at Gazuwaka and Chandrapur, i.e. by including the YTC of Talcher-Kolar HVDC bi pole link to the total YTC of SR grid. **This implies that the charges of Talcher-Kolar HVDC bi pole link shall be shared by all the DICs of the Southern Region on pro-rata basis.**

For the case of injection PoC rate of Talcher Stage-II STPS for 200 MW share of Odisha in Talcher-II STPS, this shall be as per Sharing Mechanism in the NEW grid.

The Commission has further given thought on the issue of treating all the HVDC systems in the country. It is **observed that the cost of HVDC systems is high, but they are important from the point of view of security and reliability of the whole grid**. **All the HVDCs shall be treated/ classified as national assets and once the whole country is synchronously connected, the total YTC of all the HVDC systems shall be pooled and shared among all the beneficiaries by scaling up the YTC of the all India grid.**

Accordingly, it has been proposed to substitute Step 4 under sub-para 2 of Para 2.7 of Annexure of the Principal Regulations as under:

> **"Step 4: The entire YTC of the Talcher-Kolar HVDC transmission link shall be borne by the DICs of the Southern Region by scaling up their PoC charges. PoC injection charge for 200 MW allocated from Talcher–II station to the State of Odisha shall be charged at the PoC injection rate of Talcher–II station as per Sharing Mechanism in the NEW grid.**
>
> **Provided that after the entire country is synchronously connected, the cost of all the HVDC systems shall be borne by all the DICs in the country by scaling up the YTC calculated without including the HVDC costs.**

Unquote

After considering the comments of the stakeholders on the draft proposal, the commission decided as under:

> “Step 4: The entire YTC of the Talcher - Kolar HVDC transmission link shall be borne by the DICs of the Southern Region by scaling up their PoC charges. However, the PoC injection rate for the allocated share from Talcher – II station to the State of Odisha shall be the PoC injection rate of Talcher – I station as per Sharing Mechanism in the NEW grid.
>
> Provided that after the entire country is synchronously connected, the cost of all the HVDC systems shall be borne by all the DICs in the country by scaling up the YTC calculated without including the HVDC costs.”

45.7 Though it was proposed in the draft third amendment to delete the proviso under Para 2.7 of Annexure-I, which effectively meant that "with and without method" would be adopted for calculation of HVDC charges (except for Talcher-Kolar), the Commission after keeping in view the rationale explained in the Explanatory Memorandum to the draft Second amendment and SOR to the Second amendment and the comments received from POSOCO on the draft third amendment, has decided not to go ahead with the proposed amendment. The liability for payment fo HVDC charges shall be that of the regions for which HVDC has been built.

45.8 Technical literature was referred to in this regard. It is found that there are various methods suggested for allocation of cost of HVDC system. However, as per the literature, none of the solutions is ideal which implies that methods for sharing of charges for HVDC are in evolving stage.

45.9 FERC order recognizes the concept of different cost allocation methods for different type of transmission assets as under:

> “Principle 6:
>
> Interregional Cost Allocation Principle 6: The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional transmission facilities, such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements."

45.10 In India, both types of systems are there i.e. HVDC Back to back and evacuation assets. While there is broad consensus on usage of back to back

HVDC for common grid benefit due to power flow in both directions, the evacuation assets were planned to cater the requirement of a particular set of users or a pair of Generator and Demand customers bound by PPA as power flow is mostly unidirectional, transmission cost allocation needs to be on a separate principle. As tariff of HVDC links cannot be allocated with marginal participation method, a separate treatment is unavoidable.

45.11 It is important to mention that such a different treatment of HVDC assets specifically set up for evacuation purpose under Regional Transmission planning system, prevailed in the past. The HVDC systems were treated in the following ways:

S No	Name of HVDC System	Methodology before PoC	Methodology After PoC (w.e.f 01.7.2011)	Methodology after 1st Amendment (25.11.2011)	Methodology after 2nd Amendment (29.3.2012)
1.	**Talcher-Kolar**	Sharing by SR beneficiaries including Goa in the ratio of weighted average allocation	**With and without method.**	**T-K HVDC shared by all DICs of SR**	**Existing method** **By all DICs, post synchronization of SR Grid with NEW Grid by scaling up of YTC of AC lines.**
2.	**Rihand-Dadri**	In the ratio of weighted		**With and**	
3.	**Balia-Bhiwadi**				
4.	**Mundra-Mohindergarh**	**N/A**			

HVDC Back to Back					
1.	**Sasaram**	**100 %NR**	**With and without**	**With and without**	**By all DICs, post synchronization by scaling up of YTC of AC lines**
2.	**Gajuwaka**	**100 %SR**		**50:50 SR-**	
3.	**Chandrapur (Bhadravati)**	**50:50**			
4.	**Vindhyachal**	**50.:50**		**With and without**	

***CGSs = Central Generating Stations**

45.12 It may be seen from above that prior to introducing POC in July 2011, the charges for HVDC were borne by beneficiaries for whom the asset was created.

We note that HVDC system helps in voltage control, relieving loading of intervening AC network, power oscillation damping, sub synchronous resonance damping and enhancing power transfer capability. However the benefit to other regions has not been stated by NLDC. We have decided that 10 % of YTC of the ISTS system shall be recovered through charges known as Reliability Support Charge except for capacity for which the transmission charges for any HVDC system are to be partly borne by a DIC under a PPA or any other arrangement. While HVDC Back to Back system shall be borne by all the DICs of the country, we are not inclined to distribute the cost of HVDC lines among all DICs. For allocation of remaining 90% of cost of HVDC Line, we rely on the principles for payment of HVDC historically and principle of causation (as given in FERC order 1000 in Tariff Provisions and Agreements for Interregional Transmission Coordination - page 348 – 400). In the event of better projection and appreciation of benefits of HVDC links in due course, keeping in view evolving methodologies worldwide, the Commission may consider the proposal for review of sharing of transmission charges of HVDC links. NLDC may in consultation with CEA, CTU, IITs and international consultant submit a technical report indicating various solutions for allocation of cost of HVDC system in India supported by adequate calculations.

45.13 We have also considered the view of FERC that the challenges associated with allocating the cost of transmission system appear to have become more acute as the need for transmission infrastructure has grown. FERC noted that constructing new transmission facilities requires a significant amount of capital and, therefore, a threshold consideration for any company considering investing in transmission is whether it will have a reasonable opportunity to recover its costs. It should be ensured that transmission rates are just and reasonable; the costs of jurisdictional transmission facilities must be allocated in a way that satisfies the "cost causation" principle. FERC noted that the D.C. Circuit defined the cost causation principle stating that "it has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them. Also the cost causation principle requires that the costs allocated to a beneficiary be at least roughly commensurate with the benefits that are expected to accrue to it.

45.14 Talcher-Kolar HVDC line was specifically set up for transfer of Bulk power to Southern Region (SR) constituents. Accordingly, the beneficiaries for this HVDC are Withdrawing DICs of SR and Injecting DICs with target region as SR. However, in the present Regulations, we are providing that withdrawing

DICs shall bear the injection charges for generators having beneficiaries with PPA/LTA. Hence, the charges for such HVDC will be borne by withdrawing DICs of SR and the DICs having LTA to target region (as SR). Similar logic is applicable to NR constituents for Rihand-Dadri and Balia-Bhiwadi HVDC.

45.15 Accordingly, it has been decided that 10% of YTC of these three HVDC links as discussed in para above, shall be recovered through Reliability Support Charges and the balance cost of these lines shall be borne by respective constituents in proportion to their approved withdrawal i.e. Talcher-Kolar by SR constituents and Balia-Bhiwadi and Rihand-Dadri by NR constituents. Similarly generating station which has SR or NR as target region, as the case may be, shall bear the HVDC's charges in proportion to their approved injection.

45.16 Mundra-Mohindergarh HVDC was built as dedicated line to transfer 1495 MW power to Haryana. Subsequently, it was made ISTS and M/s Adani has obligation to bear withdrawal charges of Haryana corresponding to 1495MW. Accordingly, 1495/2500 part of YTC of the HVDC line shall be borne by M/s Adani Power Ltd (APL). The remaining 1005 MW capacity can be utilized for transfer of power to any DIC in any region. Hence 1005/2500 part of YTC of the HVDC line shall be included in the PoC calculation by scaling up YTC of AC lines on all India basis. However, this arrangement will not give any right or preference to M/s APL to schedule its power on this line. The scheduling shall be done by RLDC based on system requirement. As M/S Adani Power Limited will pay transmission charges for HVDC to deliver power at Haryana periphery, and with modified approach of allocation of injection charges of Generator wherein generator would pay injection charges only for untied power, APL would not be liable to pay PoC Charges for 1495 MW, so there shall not be any double charging to APL.APL will pay MTC towards 1495 MW for Mundra-Mohidergarh HVDC as specified by Commission in the Order.

45.17 For any new HVDC line, the Commission shall decide the methodology through an order. However, the above principle of sharing of transmission charges of HVDC lines may be reviewed based on the national transmission planning, if certain HVDC systems are planned to cater to multiple needs i.e. evacuation or reliability or Renewable integration or change in the benefits derived by the stakeholders.

45.18 Accordingly, we have decided the treatment of HVDC lines as under:

"Treatment of HVDC Lines: Flow on HVDC systems is regulated by power order and remains constant for marginal change in load or generation. Hence, marginal participation (MP) of HVDC systems is zero. Since the HVDC lines were specifically set up for transfer of bulk power to specific Regions, the DICs of the Region shall share the cost of HVDC lines. HVDC lines also help in controlling voltages and power flow in inter-regional lines and some benefits accrue to all DICs by virtue of HVDC system. Accordingly, 10 % of the MTC of these systems be recovered through Reliability Support Charges. The balance amount shall be payable by Withdrawal DICs of the Region in proportion to their Approved Withdrawal. In case of Injection DICs having Long Term Access to target region, HVDC charge shall be payable in proportion to their Approved Injection.

Where transmission charges for any HVDC system are to be partly borne by a DIC (Injecting DIC or Withdrawal DIC, as the case may be) under a PPA or any other arrangement, HVDC charges in proportion to the share of capacity in accordance with PPA or other arrangement shall be borne by such DIC and the charges for balance capacity shall be borne by the remaining DICs by scaling up of YTC of the AC system included in the PoC."

45.19 Accordingly, the cost of HVDC system (other than HVDC Back to Back systems)
shall be shared as under:

a. Transmission Charges of Talcher-Kolar HVDC transmission link shall be borne by (a)Withdrawal DICs of the Southern Region in proportion to their Approved Withdrawal and (b) Injecting DICs having LTA to target region in proportion to their Approved Injection.

b. Transmission charges of Rihand-Dadri and Balia-Bhiwadi HVDC transmissionlinks shall be borne by (a) Withdrawal DICs of Northern Region in proportionto their Approved Withdrawal and (b) Injecting DICs having LTA to targetregion in proportion to their Approved Injection.

c. HVDC charges for a region shall be calculated by multiplying

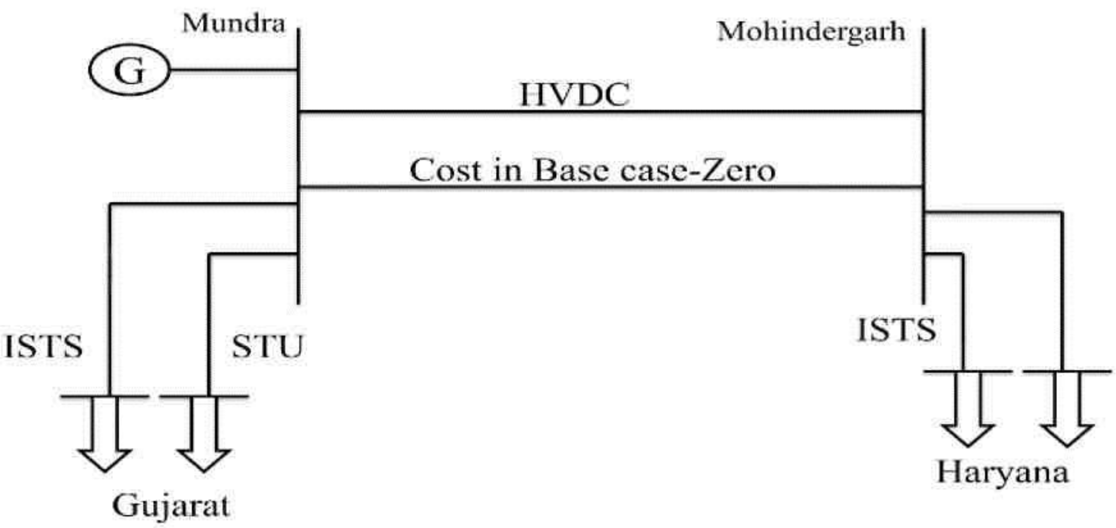
[{90% of the Monthly Transmission Charges of HVDC systems} /

{Total Approved Withdrawal of the Withdrawal DICs and Approved Injection of the Injecting DICs having LTA to target region}]

With Approved Withdrawal of the Withdrawal DICs or Approved Injection of the Generators having LTA to target region or additional MTOA, as the case may be.

d. Transmission charges of Mundra-Mohindergarh HVDC link shall be borne byM/s Adani Power Limited in proportion to its share for transfer of capacity toHaryana (1495/2500). Balance 1005/2500 of YTC of the link shall be borneby all the DICs in the country by scaling up of YTC of the AC systemconsidered in PoC.

45.20 To explain the above, the schematic diagram of HVDC system of APL is given



45.21 For 1495 MW of power the transmission charges are to be paid by M/s Adani Power Ltd. as per PPA with Haryana. Accordingly, 1495/2500 part of transmission charges of Mundra-Mohindergarh HVDC system donot form part of recovery through the PoC mechanism and are to be borne by M/s. APL itself. However, M/s. APL will not have any exclusive right on this transmission capacity.

45.22 Remaining part (1005/2500) of HVDC charges shall be considered in PoC and recovered through scaling up of YTC of the transmission system in the PoC calculations. It may be seen that Haryana uses this HVDC system for drawal of its power from Mundra TPS with transmission charges which are already built in the generation tariff. Accordingly LTA for this quantum shall not be considered in computation of Withdrawal PoC Rate of Haryana. Since in base case no cost of HVDC has been considered, Haryana uses the HVDC system at zero cost for receiving power from Mundra TPS, as per PPA, the injection of corresponding capacity transferred through HVDC doesn't affect charges of other DICs of other DICs as the HVDC cost considered in base case is Zero.

45.23 Cost of all HVDC B2B systems shall be borne by all the DICs in the country after deducting Reliability Support Charge as specified. The cost of these B2B systems shall be included in the PoC computation by scaling up of YTC of AC system or by including the Cost of all HVDC B2B system in the AC system "

4.14.7 **Analysis and Recommendations of the taskforce**

(a) Vide the third amendment it was concluded that since it is not possible to identify utilisation of HVDC on the basis of marginal participation methodology, it should be borne by beneficiaries/ DICs for whom it has been created i.e causer pays. HVDCs which are back to back systems and are used for control purpose are being put under reliability component since control function can be seen as benefiting everybody in the grid. Further 10% component of other HVDCs created fro specific regions have also been considered under reliability based on POSOCO's suggestions that these HVDCs are also used for control. However the objective quantification of how much % such HVDCs are used for control have not been provided by POSOCO or CTU. Considering that the entire HVDCs such as Talcher-Kolar, Rihand-Dadri, Bali-Bhiwadi etc are used for control is not acceptable. These systems are largely built for evacuation of power from one region to another region. Biswanathchariali-Agra has been declared as National asset by GoI and considering its peculiarities, the sharing of transmission charges for the same was done across India.

(b) Internationally it is observed that HVDC systems are paid for by the Areas which draw power through such HVDCs. It is possible because HVDCs have been set up a radial systems in these Countries. India has a unique system where HVDC and AC system is meshed within each other. Hence it is not possible to clearly identify the utilisation of such HVDC on scientific basis and hence causer pays principle is being adopted to share its charges.The usage of HVDC charges is based on the power order decided by the system operator based on various operational factors. Hence cost allocation of HVDC system cannot be based on

Load flow. HVDC is planned predominately to carry Long term power based on the system conditions. The importance of HVDC is predominately to carry Long term demand rather than meeting the peak demand of a state. Hence cost of HVDC is based on the LTA+MTOA of the region for which it is meant.

(c) Keeping in view that HVDC are largely set up for evacuation, it is recommended that existing provisions for sharing of HVDC charges on 'causer pays' principle should continue under both modified PoC method as well as Uniform charges method. HVDC back to back systems should be considered under reliability component in Modified PoC and under YTC to be shared uniformly with all entities in Uniform charges method.

(d) Currently 10% component of HVDC except back to back is covered as reliability component. In proposed modified PoC mechanism, recovery of transmission charges is done in 3 categories Usage, Reliability and Residual for AC system. Since usage for HVDC and reliability can not be quantified through load flow and considering meshed nature of HVDC and AC system with each other where flow in HVDC is controlled as per flow in AC system , it is proposed to consider All India reliability% calculated for AC network to be same as for HVDC except Back to back and National asset. MTC corresponding to % of reliablity to be shared in ratio of non coincidental peak.

(e) HVDC back to back systems should be considered under reliability component in Modified PoC and under YTC to be shared uniformly with all entities in Uniform charges method. HVDC declared national assets to be shared as per CERC orders.

(f) With regards to HVDC charges for MTOA customers, it is clarified that HVDC charges are shared by MTOA customers in the same ratio as LTA customers. Further we agree that HVDC charges should also be paid by STOA customers till mechanism of GNA comes into place where no separate charges for STOA are envisaged.

(g) During meeting of taskforce, representative of POSOCO had suggested that it may happen that HVDC created for specific region is used for transfer of power in reverse direction with upcoming renewables for eg. Talcher-Kolar or Raigarh-Pugulur. In such circumstances, the methodology of HVDC sharing may be reviewed.

TOR 5: Suggest modifications required in the Existing mechanism in due consideration of future market scenario, large scale capacity addition of renewable, introduction of GNA concept for transmission planning, introduction of ancillary services and reserves, support by international experience in this regards;

4.15 International experience with respect to transmission cost allocation

(a) The taskforce carried out extensive literature survey through papers available on internet and as provided by professors and members of the taskforce with respect to international experience. A list of such references are annexed.

(b) A report by PJM named “ A Survey of Transmission Cost Allocation Issues, Methods and Practices” dated March 2010 states as follows:

"That simple question dominates the policy discussion about transmission expansion. The debate typically hascentered on the choice between "beneficiary pays" and "socialization," which have different meanings to differentstakeholders. Generally, proponents of "beneficiary pays" argue that those parties benefitting from transmissionshould pay the costs of building transmission, with the implicit assumption that all benefits can be assigned toindividual parties. Proponents of "socialization" argue the most important benefits – such as reliability – cannotbe easily assigned because all parties enjoy these benefits, and therefore costs should be spread over all usersconnected to the transmission system.

In practice, there is no broad consensus on precise definitions for "beneficiary pays" or "socialization", as evidencedby stakeholder disagreement over who should be considered beneficiaries or what constitutes socialization. Thus,it is exceedingly difficult to apportion transmission costs in a way that satisfies all stakeholders. Moreover, theremay be other considerations, such as ease of administration and understanding, or stability of the allocation overtime, that may drive stakeholder preferences for a particular allocation method.
As the nation's economy rebounds, state and federal environmental mandates are implemented, and greateramounts of intermittent wind and solar generation (often located in remote locations) integrate into the grid, moretransmission will be needed – yet the assignment of transmission costs remains among the electric industry'smost contentious issues."

The report briefs cost allocation methods under following heads

Transmission costs can be allocated:

• **Between load and generation:** A threshold question is whether to assess costs to load or generation. The general practice among RTOs in the U.S. is that load pays transmission costs. A contrasting view, which has been implemented in some other countries, is that generators use transmission to deliver energy to customers and therefore are beneficiaries that should be allocated some transmission costs.

• **By amount of usage:** Allocating costs based on the annual megawatt-hours of consumption and/or generation, regardless of location or peak usage is a simple way to spread costs over a wide base under the implicit assumption beneficiaries are difficult to identify.

• **By peak consumption or generation:** This method also spreads costs to all users of the transmission system based upon their maximum amount of load or generation, which is usually measured at the system peak, without regard to location.

• **By flow-basis:** Power flow models that are used to plan future transmission and to determine locational marginal prices in energy markets can be used to identify users' physical impacts on the transmission system by their location or the amount of power flows they affect. The "beneficiary pays" concept can be applied using this flow-based method.

• **By a monetary impact basis:** This is a form of "beneficiary pays" that assigns costs to those parties who receive a monetary gain, such as changes in energy prices or production costs. This method is compatible within or between organized wholesale markets that use locational pricing, where economic benefits of proposed projects can be estimated through market simulations.

(c) The Report concludes following

"*Key Conclusions*

Consider priorities when determining cost allocation.

The choice of allocation method depends on the priorities stakeholders place onthe type of benefits and practical considerations. For example, stakeholders maysuggest that some costs be allocated through flow-based or monetary metricmethods because it's important to identify and ensure that "beneficiaries" arespecifically allocated costs, and it is important for cost allocation to be consistentwith transmission planning. Implicit in this choice is that ease of understanding andadministrative burden are not too important.

Conversely, if there is a strong emphasis on grid reliability which benefits everyone,or the fact that all users benefit from reduced losses with new transmission facilities,or if ease of understanding and administration are important, then allocating costsacross all MWh or all peak MW may be considered desirable.

Cost allocation is a societal decision.

Cost allocation is a public policy mixed with engineering, economic and politicalconsiderations. By its very nature, cost allocation must serve individual as wellas collective interests. It demands regulatory prescription or approval, just liketransmission siting and reliability.

A combination of methods is common practice, reflecting the diversity of priorities.

U.S. and international practice with regard to cost allocation show a patternof "mixing and matching" elements of the various methods for allocatingtransmission costs.

Most ISOs and RTOs in the U.S. use this hybrid "mix and match" approach, spreadingsome costs over peak MW to load while other costs are allocated using flow-basedmethods. Internationally, there is a willingness to "mix and match" different costallocation methods as well. Reasonable arguments support all of these methods."

(d) The Report provides a brief practices over the three types of methodologies:

a. Megawatt-hours
b. Peaks
c. Flow based methods

(e) A brief of each type of method is detailed below:

"U.S. Practice in Allocating Costs over Megawatt-Hours

The California ISO allocates transmission cost over megawatt-hours for transmission facilities at 200 kV andabove. The New York ISO allocates costs to transmission customers on a megawatt-hour basis, but the allocationof costs for new transmission projects to transmission zones are allocated based on a combination of peak loadand location-based methods. While not in actual operation, there is currently a proposal in the Midwest ISO,
as previously mentioned, known as the "Injection/Withdrawal" proposal, that would shift the allocation of sometransmission costs over to a megawatt-hour-basis for both load and generation.

International Practice in Allocating Costs over Megawatt-Hours

International practice is split into two different categories of allocating some transmission infrastructure costs overmegawatt-hours. The first is a simple allocation over megawatt-hours generated or consumed. All EU countriesallocate some portion of their transmission costs through megawatt-hour charges, though only six countriesallocate all transmission costs on a megawatt-hour basis.Transmission companies in Australia have the optionto allocate a portion of its transmission costs on a megawatt-hour basis.In Norway, the transmission companyStatnett allocates costs to generation through the use of megawatt-hour charges.The other method for allocating transmission costs on a megawatt-hour basis uses the so-called marginal loss and/or congestion surplus – the difference between what is collected in locational energy prices from load and whatis paid out in locational energy prices to generators to cover the cost of transmission. The use of congestion ormarginal loss surplus as a means to recover transmission costs introduces a locational component into megawatthourcharges, but only covers of portion of transmission infrastructure costs and requires additional means bywhich to recover the cost of transmission infrastructure. The use of congestion and marginal loss surplus isexplicit in Argentina and Chile where the nodal pricing of energy is employed.Norway and Sweden explicitlyinclude marginal losses in their tariff structures and presumably any surpluses would go toward covering the costof transmission infrastructure.

Congestion and Marginal Loss Surplus, ARR/FTR Allocations and Cost Allocation

There is a distinct difference in the way prices by location (to account for congestion and marginal losses) aretreated internationally relative to the United States. The use of congestion and marginal loss surpluses as amethod for allocating and recovering the cost of transmission infrastructure implies that any remaining chargesallocated to transmission customers are lower than they would be otherwise.In the case of

New Zealand's nodal pricing, the surpluses are rebated back to transmission customers rather thandirectly going toward the recovery of infrastructure costs.In Brazil, energy prices are computed on a zonal basisaccounting for congestion and marginal losses, but adjust marginal losses so that there is no surplus.However,the use of congestion surpluses as a rebate or as a way to cover transmission costsleaves no mechanism for transmission customers to hedge against congestion costs.In U.S. RTO markets with locational marginal pricing or nodal pricing such as PJM,transmission customers paying for the infrastructure are allocated Auction RevenueRights (ARRs) which can then be converted directly into Financial Transmission
Rights (FTRs) or sold at auction, the proceeds of which are a hedge againstcongestion costs. The congestion rents are used to pay the holders of FTRs whohold these rights as a hedge against congestion rather than being used to recovertransmission infrastructure costs. With all else being equal, transmission customersare allocated a larger cost for transmission charges. However, in exchange for thatthey receive a hedge against future congestion costs.

Transmission Planning Context

In the context of transmission planning studies, the allocation of costs overmegawatt-hours does not correlate, in general, with how the system is plannedbecause the impact at system peak and the location of generation and/or load maynot be a consideration in allocating costs. Loads that are large consumers and haveflat load profiles do not drive system peaks and may be allocated greater costsrelative to being allocated costs over peak usage which drives planned transmissioncapacity additions. If the allocation of costs over megawatt-hours is not locationallydifferentiated, all else equal, loads close to generation may bear greater costs thantransmission power flow studies would indicate such loads are causing as representedby distribution factors.

In contrast, loads with low load factors, but contributing much to the system peak,may be allocated a smaller portion of the cost relative to their contribution to theneed for transmission expansion to meet peak load conditions. Loads far fromgeneration could pay less than the relative impact they have on the transmissionsystem at peak as represented by distribution factors used in transmission powerflow studies.

However, if the allocation of costs over megawatt-hours encompasses the use ofmarginal loss or congestion surpluses, then there is a locational component in theallocation of costs that corresponds to transmission power flow studies. Loads farfrom generation (and generation far loads) contribute relatively more to losses,for example, and would be charged accordingly. On net the use of the marginalloss or congestion surplus to cover transmission infrastructure costs accounts fortransmission system impacts by location of the users of the system.

Understandability and Administrative Ease

Allocating costs over megawatt-hours is relatively simple for loads and generation to understand because the rate is the total cost of transmission divided by the total megawatt-hours of consumption and/or generation. The allocation could be forwardlookingby using a forecast of consumption and/or generation during the next year,or the allocation could be retrospective by allocating costs based on megawatt-hoursof consumption and/or generation from the previous year. From an administrativeperspective, all that is needed to set the rate is the forecast or previous year totalconsumption and/or generation in megawatt-hours as the divisor, and the total costsof transmission, which are already known.

The use of marginal loss or congestion surplus is slightly more complex to explain tomarket participants and may be slightly more difficult to administer, but otherwisehas the same properties as allocating costs over non-locationally differentiatedmegawatt-hours.

U.S. Practice in Allocating Costs over Peaks

In current practice, most RTOs in the U.S. allocate some or all transmission costs based upon some idea ofcoincident or non-coincident peak load or generation. However, peak load or generation is not always employed as the sole means to allocate costs of transmission additions/upgrades but is a complementary part of cost allocationpractices in the U.S.PJM allocates all costs associated with transmission facilities at 500 kV and above based on each zone'scontribution to the non-coincident zonal peak64; for transmission upgrades below 500 kV PJM allocates costs totransmission zones based on flow impacts determined from peak conditions.Similarly, the New York ISO usescoincident system peak conditions in conjunction with other criteria to allocate the cost of reliability upgradesto individual zones, although individual customers are allocated costs on a megawatt-hour basis. The MidwestISO allocates part of its transmission expansion costs to transmission customers based on monthly coincidentzonal peaks. SPP allocates its transmission upgrade costs based on monthly zonal peak, but also has a flowbasedcomponent to its allocation.The California ISO uses an interconnecting resource's maximum capacityto allocate costs on Location Constrained Resource Interconnection Facilities (LCRIFs). ISO New Englandallocates all costs associated with transmission upgrades through peak charges and does so based on monthlypeaks rather than annual system peaks. ERCOT allocates all transmission costs based on the share of averagemonthly coincident system peak over the months of June through September.

International Practice in Allocating Costs over Peaks

All but six EU countries allocate some portion of their transmission costs through charges based on some kind ofpeak megawatt concept, but none uses peak load or generation allocation to recover all transmission costs. Forexample, in Great Britain generators are allocated costs based on their maximum capacity, and loads are allocatedcosts based on their usage at the three coincident peaks after accounting for locational impacts. Statnett inNorway allocates costs to load via charges based on the average peak loads over the previous five years.Sweden allocates costs based on network capacity reservations, which presumably would match the potential peak usage.Australia and New Zealand also allocate a portion of their transmission costs on a peak-load basis.Generators on the South Island in New Zealand are charged for the HVDC link based upon their maximuminjections at any point in time.

In South America, Brazil allocates approximately 80 percent of its transmission costs based on peak loads ormaximum generating capacity.Much like the U.S., international practice in employing cost allocation over peak load or generation generally isused as a complement to some other method. In many cases, such as in Australia, Great Britain, Sweden, Norwayand Brazil, this method is complementary to the use of location-based or flow-based methods.

Transmission Planning Context

Because transmission is generally planned to meet the system peak, the allocationof costs over peak megawatt use and/or generation matches the way the system isplanned. It also tends to allocate a greater portion of the cost to loads with low loadfactors that contribute much to the system peak commensurate with their impactsat peak. In contrast to allocating costs over all megawatt-hours of consumption and/or generation, allocating costs over peak megawatts tends to reduce the allocatedshare of costs to loads that have flat load profiles (high load factors).However, cost allocation over peaks alone does not account for the location ofgeneration and/or load. Peak loads close to generation could pay more than therelative impact they have on the transmission system according to distributionfactors, while similar-sized peak loads far from generation could pay less than theirrelative impact on the transmission system according to distribution factors.

Understandability and Administrative Ease

Allocating costs over all peak megawatt usage and/or generation is relatively simplefor loads and generation to understand in that the rate is the total cost of transmissiondivided by the total megawatts at peak. The rate could be made forward-lookingby using a forecast of peak megawatt use and/or generation during the next year,or the allocation could be done retrospectively by allocating costs based on peakmegawatt use and/or generation from the previous year. From an administrativeperspective, all that is needed to set the rate is the forecast or previous year's peakmegawatt by transmission customer and in total as the divisor and the total costs oftransmission, which are already known, to derive the rate system-wide and the costfor each customer.

Flow-Based Methods Defined

Flow-based methods link flows on particular transmission assets back to loads and generation through the useof distribution factors and allocate costs according to a market participant's relative impact on transmissionfacilities. In transmission planning, load flow studies' distribution factors are used to determine the impact of loadand generation on transmission facilities at forecast system peaks. Distribution factorsalso are used to determineimpacts of load and generation on flows that ultimately determine LMPs during actual real-time system dispatch.Given that the cost allocation corresponds to the impacts of load and/or generation on transmission facilities,flow-based methods can be considered related to the idea of beneficiary pays.

Flow-based methods can allocate costs based on loads and/or generation that have contributed to the reliabilityor deliverability violation prior to the implementation of a transmission solution for those violations. In this case,the determination of the beneficiaries assumes that those who contributed to the violation benefit from resolvingthe violation and that the beneficiaries remain fixed over time.

Flow-based methods may also define beneficiaries as those loads and/or generators that contribute to flows on thepgraded facility. Those parties using the facility, as determined by their distribution factor impacts, are deemedto benefit without regard to the flows that may have caused the violation. Defining beneficiaries in this mannerallows for the possibility of the set of beneficiaries changing over time as the power system evolves with changingtransmission and generation infrastructure and changing load patterns.

A proxy for using flow-based methods to allocate costs are location-based methods where geographic locationassumed to determine the impact of generators or load on flows over transmission assets. Location-based methodscan be a reasonably accurate proxy for flow-based methods in transmission systems that are more radial in natureand loop flows are not prevalent.

U.S. Practice in Allocating Costs by Flow Basis

Reliability-Based Upgrades

In current practice, most RTOs in the U.S. employ some type of locational differentiation, usually based on flowsas determined by distribution factors to allocate some part of transmission costs. In most cases, the use of flowbasedmethods is combined with the use of the system at peak use – coincident or non-coincident – in order todetermine the cost allocation.ERCOT has no location-based cost allocation scheme, but only allocates costs over system peaks. ISO-NewEngland has a procedure to identify potential localized costs stemming from a transmission upgrade that wouldbe allocated to a subset of load in the RTO. The California ISO has the notion of Locationally ConstrainedResource Interconnection Facilities for some generator interconnections but otherwise has no locational basis forallocating transmission costs.PJM allocates all costs associated with transmission facilities below 500 kV built for reliability based on thecontribution of load at system peak to flows contributing to violations.Those loads zones contributing to theviolations are considered the beneficiaries of the upgrade and are allocated costs based on their distribution factorcontribution to flows that resulted in the violation. Given the prospective nature of the beneficiary determination,the cost allocation remains fixed over the life of the upgraded asset.PJM and the Midwest ISO also use distribution factors on constrained facilities to determine cost allocation ofcross-border facilities built to relieve constrained cross-border transmission facilities. Each RTO then uses itsown internal cost allocation method to allocate the RTO share of costs of the cross-border facility to load withinthe RTO.The Midwest ISO employs a distribution factor methodology for allocating all costs of transmission upgrades. Fortransmission at 345 kV and above, it allocates 20 percent of the upgrade costs on a system-wide basis basedon peak load shares and the remaining 80 percent based on distribution factor methods, while 100 percent ofupgrade costs from 100 kV to 344 kV are allocated to zones based on distribution factor methods.Similar to the Midwest ISO, SPP's method allocates 33 percent of the cost of reliability-based transmissionupgrades system-wide and the remaining 67 percent on a megawatt-mile basis as determined by the use of loadflow models.The location-based cost allocation in the New York ISO uses an iterative method to determine locationalallocations for upgrade costs, examining location specific reliability violations, and, if transmission solutions tothose violations alone are sufficient for the system, the local zones alone pay for the upgrades. The processworks outward to a system-wide level where any required upgrades would be allocated system-wide and thenback to examining violations due to constrained interfaces where costs would be allocated only to those zonescontributing to the flows on the constrained interfaces.

Economic-Based Upgrades

The RTOs that employ location-based or flow-based methods for reliability upgrades also use similar flow-basedtools in evaluating economic upgrades. However, the focus of cost allocation for economic upgrades emphasizesmonetary metrics rather than actual flows or geographic location, as will be seen below.

International Practice in Allocating Costs by Location or Flow Basis

The international trend is toward the use of location-based or flow-basedmethods to allocate and recover at least some portion of transmission costs.In some cases, flow-based methods to recover transmission costs are usedto provide locational signals to generators and load in markets where thereis no nodal or LMP pricing. For example, in Great Britain, where there isno LMP in the energy market, a charge is derived from a load flow analyseswhich differentiates a portion of transmission charges based on location.88 Generators in the north and loadsin the south of the country pay higher locational charges, while generators in the south (around London) mayactually face negative charges because they are close to the load center.89 Generators close to the load center mayeven be paid for free up transmission capacity due to their location under this method. However, the locationalcharges in Great Britain do not recover the entirety of transmission costs, and the remaining costs are recovered based on usage at system peak.Sweden uses any marginal loss surplus and marginal loss differences to provide a time and locational basisto cost allocation for transmission. The remaining transmission costs
are recovered through a geographicallydifferentiated cost allocation designed to capture what flow-based allocations would capture. Generators facehigher charges in the north where generation is located, and lower charges in the south closer to the load centers,while load in the north faces lower charges than load in the south.Norway is similar to Sweden in that it usescongestion and loss surpluses which are locationally based, but otherwise uses identical peak charges for loadand megawatt-hour charges for generation in a departure from the Swedish

methodology.Around the Pacific Rim, South Korea allocates 50 percent of transmission costs based on load-flow methods,and Australia similarly uses flow-based methods to allocate approximately half of transmission costs.Flow-based methods, often referred to as "area of influence" methods, are prevalent inLatin American markets, being used in Argentina, Chile and Brazil. In Argentina andChile, congestion and marginal loss surpluses from nodal pricing (LMP) are used toallocate and recover some portion of transmission cost.The costs allocated throughthe area of influence method are based on the impacts online or transformer flows. In Argentina, upgrades are based on economics as well as reliability. Proposedtransmission upgrades must be approved by 70 percent or more of the identifiedparties that would affect flows on the new facility and consequently pay forthe facility in a manner similar to what is done for economic upgrades in theNew York ISO.In Brazil, the flow-based cost allocation recovers only approximately 20 percent ofall transmission costs because the measured flows on lines is quite low on average,whereas facilities that would be close to fully loaded would have a larger portionrecovered through the flow-based allocation. Another charge, based on peak usagefor load or maximum capacity for generators100, is assessed in order to recover theremaining 80 percent of transmission costs as has been referenced above.

Transmission Planning Context

Flow-based and location-based methods can be viewed as a direct offshoot oftransmission planning studies. Market participants are charged according to theimpact they have on transmission facilities, which accounts for their locations relativeto generation and loads on the system at system peak. Loads and/or generators thathave greater impacts on transmission facilities according to the flows they cause paya greater share of costs associated with those transmission facilities. Loads and/orgenerators that have smaller impacts on flows on transmission facilities pay a smallershare of the costs associated with those transmission facilities. Large peak loadsclose to generation will pay a relatively smaller share of transmission costs than largepeak loads that are far from generation, who pay a greater share of transmission costs.

Along the same lines, if generators are allocated cost responsibility, generators farfrom load have greater impacts on transmission and correspondingly are allocated agreater share of transmission cost; generators close to load have smaller impacts ontransmission and are allocated a smaller share of transmission cost.

In contrast to allocating costs either by total megawatt-hours of consumption and/orgeneration or by peak megawatt usage and/or generation, in flow-based methods theelectrical location of the load and/ or generation is a determinant in how costs areallocated. Costs are allocated to loads and/or generation according to their impacts onthe transmission system in terms of both peak usage and location.

Understandability and Administrative Ease

Allocating costs based on the impacts of individual loads or generators based ondistribution factors, while intuitively appealing to some, is a more complex costallocation method for load, generation and other interested parties to understand inpractice than the allocation of costs over megawatt-hours or peak megawatts. Theversion of the flow-based cost allocation method used also may affect the ease ofunderstanding with a method that remains fixed over time potentially being easier tounderstand than a method that may change cost allocation shares over time.The administrative burden of flow-based methods also depends upon the choiceof whether beneficiaries are determined based on contributions to the violation forwhich the new transmission facility is designed to resolve or whether beneficiariesare determined by the impacts of parties on the new facility itself. Determination ofbeneficiaries prior to the new transmission facility is easily taken from the distributionfactors in the power flow study identifying the violations. And, given these beneficiaries remain fixed over time,this method would be administratively straightforward.Determining beneficiaries by impacts after the transmission facility has gone into service and allowing the setof beneficiaries to change over time is administratively more difficult. Power flow studies based on the actualsystem peak conditions would be required each year to derive the distribution factors applicable to loads and/orgeneration in order to determine the cost allocation. Such an exercise is not insurmountable but requires moretime and resources than other allocation methods discussed to this point.Location-based methods such as the method employed in Sweden is administratively easier to carry out asgeography serves as a proxy for power flows.

(f) Report observes that many cost allocation methodologies in use around the world today allocate some costs based on a notion of beneficiary pays, and the remaining costs are socialized in some way. Examples of this can be seen in PJM, theMidwest ISO, New York ISO and SPP in the United States as outlined in Appendix B. Internationally, Australia,Brazil and Great Britain allocate some portion of costs through flow-based methods, with the remainder spreadout over peak MW as shown in Appendix C, but each country has developed its own split on how it allocates such costs and what portions are allocated to generation and what portions are allocated to load.

Ways to Evaluate Cost Allocation Methods

Characteristic	MWh – Energy consumed or produced	Peak MW Usage	Flow Based	Monetary Metrics
Understandability *Can stakeholders understand how costs are allocated?*	Simple	Simple	Complex	Complex
Administrative ease *How easily can necessary data be gathered and used to allocate costs?*	Easy – use megawatt consumption / generation over past year or forecast for next year.	Easy – use the previous year's peak megawatt or forecast for next year.	Not so easy – beneficiaries are determined through power flow studies based on relative impact on transmission facilities.	Not so easy – beneficiaries are determined through market simulations based on monetary gain.
Reflect system changes over time *Is load growth or other changes in system conditions reflected in the cost allocation method?*	Yes – Changes in total consumption/ generation result in changes to the allocation of costs.	Yes – Changes in peak usage or generation result in changes to the allocation of costs.	Maybe – Prospective identification of benefits probably remains fixed over time. Updates to identification of benefits is possible.	No – Monetary beneficiaries are likely to remain fixed over time because it identifying financial impacts on an on-going basis is complex.
Stability of rates *Do rates derived from the cost allocation method remain stable over the life of the transmission project?*	Probably yes -- As long as use doesn't change dramatically from year to year, rates will remain relatively stable.	Probably yes -- As long as peak consumption or generation doesn't change relative to other parties, rates will remain relatively stable.	Maybe – Prospective identification of beneficiaries and rates likely remains fixed over time. Updating identification of beneficiaries is possible but may change rates.	Yes – Monetary beneficiaries are likely to identified prospectively and remain fixed over time. Updating would require extensive modeling and scenario analysis.

Characteristic	MWh – Energy consumed or produced	Peak MW Usage	Flow Based	Monetary Metrics
Incentives for generation and load *Are incentives created that reinforce or counteract the incentives provided within existing wholesale energy and capacity markets?*	Reinforces incentives to reduce electricity use through energy efficiency. May introduce inefficiencies if applied to generation.	Reinforces existing incentives to reduce peak usage through energy efficiency and demand response.	Reinforces incentives for loads to reduce use through energy efficiency or demand response. Additional long-term incentive to locate load and generation in a place that would help reduce congestion.	Reinforces incentives for loads to reduce use through energy efficiency or demand response. Additional long-term incentive to locate load and generation in a place that would help reduce congestion.
Public good aspects *Are public good features (like reliability) recognized as part of a cost allocation method?*	Yes – Implicit recognition that all consumers enjoy public good (like reliability.) Higher volume consumers enjoy reliability more and pay more relative to lower volume consumers.	Yes – Implicit recognition that all consumers enjoy public good (like reliability.) Higher peak-load consumers enjoy reliability and pay more relative to lower peak-usage consumers with lower peak generation.	No – Costs are allocated based on relative impact on transmission facilities. Public good is generally not recognized.	No – Costs are allocated based on financial impact. Public good is generally not recognized.
Are positive externalities (reduced losses) recognized?	Yes – Reduced losses are enjoyed by all users. Higher volume consumers enjoy greater benefit from reduced losses and pay more relative to lower volume consumers.	Yes – Reduced losses are enjoyed by all users. Higher peak-load consumers enjoy greater benefit from reduced losses and pay more relative to lower peak-usage consumers with lower peak generation.	No – Positive externalities generally are not recognized. No costs are allocated to others who may benefit from reduced losses.	No – Positive externalities generally are not quantified. No costs are allocated to others who may benefit from reduced losses.

4.16 Disputes observed in transmission pricing internationally

(a) In India PoC mechanism has become a political issue. We have found that similar was the situation in New Zealand and FERC, a brief of experience is detailed below:

(b) Disputes handled by FERC has been captured in Richard J. Campbell, Specialist in Energy Policy, has noted as follows in its paper Electricity Transmission Cost Allocation dated December, 2012 as follows:

(i) For many years, the Federal Energy Regulatory Commission (FERC) declined to go beyond establishing general principles as set forth in its Order No. 890, which addressed "undue discrimination and preference" in the providing of transmission services. Transmission cost allocation proposals made by transmission service providers were therefore reviewed by FERC to ensure compliance with the general principles outlined in Order No. 890 and the Federal Power Act (FPA). However, there were calls for FERC to provide a clearer framework for cost allocation. The decision of the Seventh Circuit in Illinois Commerce Commission v. FERC, to reject a cost allocation plan approved by FERC which would have permitted "socialization" of the costs for some new transmission projects (i.e., allowing the costs to be spread widely among ratepayers in the PJM Interconnection, even those who do not substantially or clearly benefit from a project) encouraged FERC to seek more clarity with respect to cost allocation. Congress also entered the fray in the form of legislative proposals that would amend the Federal Power Act to include new transmission cost allocation guidelines that FERC would be required to follow. In 2009 FERC decided to take an in-depth look at cost allocation and other transmission planning issues as part of a new docket. FERC observed that its "best remaining opportunity to eliminate barriers to new transmission construction may therefore be to provide greater certainty in its policies for allocating the cost of new transmission facilities, particularly for facilities that cross multiple transmission systems." FERC requested comments from stakeholders on transmission planning issues. After receiving and reviewing comments from stakeholders and offering a proposed rule in 2010, FERC published Order No. 1000, a final rule reforming FERC's transmission planning and cost allocation requirements for transmission service providers, on July 21, 2011. The final rule required transmission service providers to (1) participate in a regional transmission planning process; (2) amend their transmission tariffs to provide for consideration of public policy; (3) remove from their tariffs a federal right of first refusal for certain new transmission facilities; and (4) improve coordination between neighboring transmission planning regions.

(ii) The paper provides details of cost allocation in PJM and associated disputes that arose as follows:

"PJM Interconnection

The cost allocation process established by PJM and approved by FERC allocated costs in terms of the physical characteristics and purpose of the proposed transmission line:

- The cost of projects planned by individual utilities to meet local needs rather than system-wide needs are to be charged to the customers in the zones of PJM that benefit (i.e., beneficiary pays).
- Beneficiaries are also to pay for new projects with a rating of less than 500 kilovolts (kV). FERC directed PJM and its customers to develop a standard methodology for allocating the costs of such projects.
- For "backbone" transmission projects with a rating of 500 kV or greater—that is, the proposed lines with the greatest capability to move large amounts of electricity—costs would be socialized throughout the PJM Interconnection (i.e., all customers within PJM would pay a portion of the costs of the facilities, regardless of their location relative to where the upgrades were made, on the assumption that all customers would benefit from these "backbone" upgrades).

The socialization of the costs of 500 kV and greater facilities was controversial from the outset; for example, the Illinois utility commission reportedly characterized it as "not only unjust and unreasonable, but patently irrational."31 On August 6, 2009, the United States Court of Appeals for the Seventh Circuit, in response to petitions filed by the Ohio and Illinois utility commissions, rejected PJM's cost socialization approach and remanded the issue to FERC. The court stated that:-

> "FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members.... No doubt there will be some benefit to the midwestern utilities just because the network is a network, and there have been outages in the Midwest. But enough of a benefit to justify the costs that FERC wants shifted to those utilities? Nothing in the Commission's opinions enables an answer to that question."

Legislative Efforts to Dictate Transmission Cost Allocation Principles

As described above, the FPA's only direction regarding the allocation of transmission costs are that the rates charged for transmission service must be "just and reasonable." This gives FERC broad authority to dictate transmission cost allocation policy, although that authority has its limits, as the Illinois Commerce Commission decision demonstrates. However, in recent years Members of Congress have introduced legislation intended to provide a tighter framework for FERC's transmission cost allocation policy. In the 112th Congress, at least one bill has been introduced that would amend the FPA to specifically address transmission cost allocation. S. 400, introduced on February 17, 2011, by Senator Bob Corker, would amend Section 205 of the Federal Power Act to provide that: No rate or charge for or in connection with the transmission of electric energy contained in any filing made [by a public utility] after June 17, 2010 shall be considered just and reasonable unless the rate or charge is based on an allocation of costs for new transmission facilities that is reasonably proportionate to measurable economic or reliability benefits projected, as determined by the Commission, to accrue to the 1 or more persons that pay the rate or charge. This was not the first legislative effort to adopt principles for transmission cost allocation requiring that costs be allocated in a way that is "reasonably proportionate to measurable economic or reliability benefits." During the 111th Congress, the Senate Committee on Energy and Natural Resources reported out of committee S. 1462, the American Clean Energy Leadership Act. The bill contained an amendment proposed by Senator Corker that would direct FERC to issue a new electricity transmission cost allocation rule that could allow for "allocation of the costs of high-priority national transmission projects to load-serving entities within all or a part of a region, except that costs shall not be allocated to a region, or sub-region, unless the costs are reasonably proportionate to measurable economic and reliability benefits."51When the amendment to S. 1462 was proposed during the 111th Congress, some advocates of new electricity transmission construction expressed concern that it would limit FERC's ability to spread costs widely among all users in a given region.52 They also argued that the benefits from a new transmission project may accrue over many years and therefore may not presently be "measurable."

FERC Chairman Jon Wellinghoff was also critical of the amendment, saying that it would both restrict the Commission's ability to spread transmission costs across the region and also needlessly tie up FERC in litigation over individual transmission cost allocations.

Three former FERC chairmen also voiced their disapproval of the amendment, noting in a letter that the amendment could "hamstring" FERC and that the language could jeopardize planned infrastructure investment due to uncertainty about cost recovery

ORDER 1000

While FERC declines to specify a standard or preferred methodology in Order No. 1000, it does require each regional or interregional cost allocation method to satisfy six generalized cost allocation principles:

•Regional cost allocation principle 1: The cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits.

Interregional cost allocation principle 1: The costs of a new interregional transmission facility must be allocated to each transmission planning region in which that transmission facility is located in a manner that is at least roughly commensurate with the estimated benefits of that transmission facility in each of the transmission planning regions.

•Regional cost allocation principle 2: Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of those transmission facilities.

Interregional cost allocation principle 2: A transmission planning region that receives no benefit from an interregional transmission facility that is located in that region, either at present or in a likely future scenario, must not be involuntarily allocated any of the costs of that transmission facility.

•Regional cost allocation principle 3: If a benefit to cost threshold is used to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation, it must not be so high that transmission facilities with significant positive net benefits are excluded from cost allocation.

Interregional cost allocation principle 3: If a benefit-cost threshold ratio is used to determine whether an interregional transmission facility has sufficient net benefits to qualify for interregional cost allocation, this ratio must not be so large as to exclude a transmission facility with significant positive net benefits from cost allocation.

•Regional Cost Allocation Principle 4: The allocation method for the cost of a transmission facility selected in a regional transmission plan must allocate costs solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs.

Interregional Cost Allocation Principle 4: Costs allocated for an interregional transmission facility must be assigned only to transmission planning regions in which the transmission facility is located. Costs cannot be assigned involuntarily under this rule to a transmission planning region in which that transmission facility is not located.

•Regional Cost Allocation Principle 5: The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.

Interregional Cost Allocation Principle 5: The cost allocation method and data requirements for determining benefits and identifying beneficiaries for an interregional transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed interregional transmission facility.

•Regional Cost Allocation Principle 6: A transmission planning region may choose to use a different cost allocation method for different types of transmission facilities in the regional transmission plan, such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements.

Interregional Cost Allocation Principle 6: The public utility transmission providers located in neighboring transmission planning regions may choose to use a different cost allocation method for different types of interregional transmission facilities, such as transmission facilities needed for reliability, congestion relief, or to achieve Public Policy Requirements.

4.17 Analysis carried out by taskforce with respect to various options

(a) The taskforcerequested NLDC to carry out comparative analysis of PoC cases as detailed below. NLDC carried out the analysis on Q1-2017-18 case for the following scenarios:

1. The comparative analysis of PoC transmission charges on Average demand case vs Peak demand PoC result
2. Comparison of results with and without slabs
3. Comparison of results with Uniform all India Postage stamp vs PoC charges method
4. Identification of lines which are marginally used and its sharing based on socialisation
5. Comparison of transmission charges with 3 slabs, 5 slabs, 7 slabs, 11 slabs and 13 slabs
6. Comparison of Actual Peak Demand vs Projected Peak Demand as considered in POC Calculations

4.17.1 The comparative analysis of PoC transmission charges on Average demand case vs Peak demand PoC result

(a) The ratio in which transmission charges to be shared among the beneficiaries also depends upon the ratio of demand of each beneficiaries considered in the studies for computation of charges for each beneficiary.

(b) The ratio of average demand of all the beneficiary would differ from the ratio of peak demand of all the beneficiaries, hence the ratio of the cost sharing among the beneficiaries would vary.

(c) Comparison of transmission charges to be paid for sample case showing increase / decrease in PoC charges:

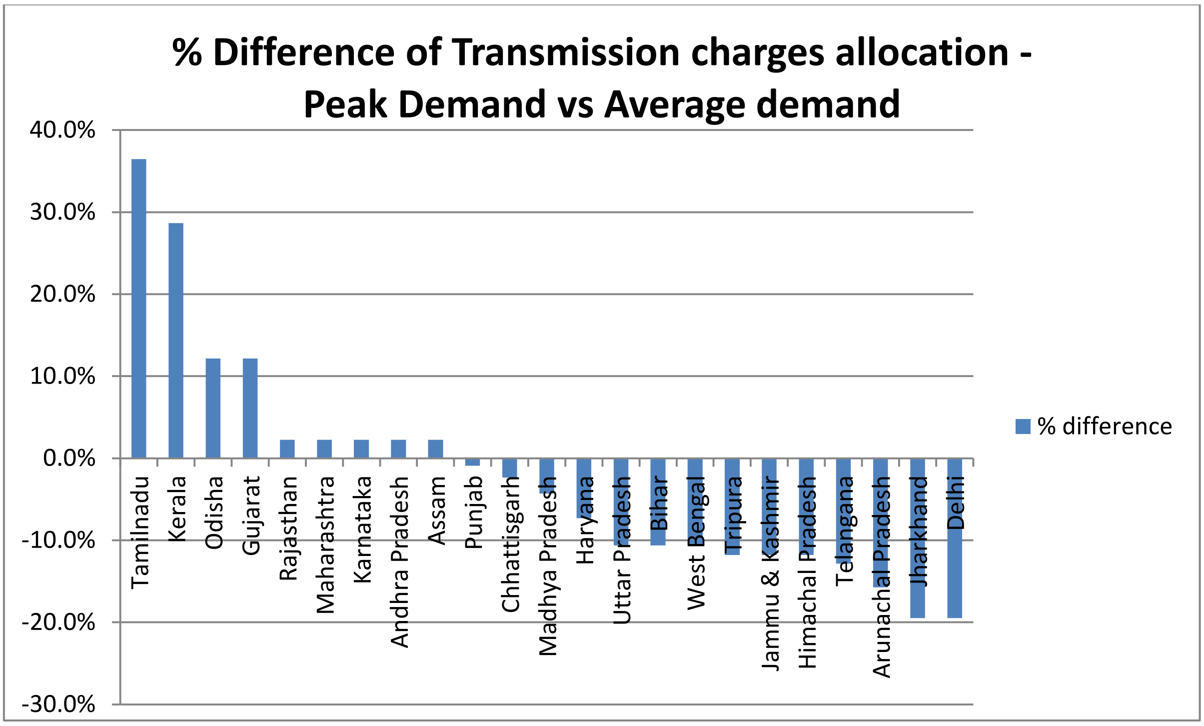


Figure 14: Percentage difference of transmission charges allocation on States under peak demand vs average demand

(d) It is observed from above that in case average case is considered, Delhi, U.P., Jharkhand, Telangana are benefitted whereas Tamil Nadu, Kerala, Odisha, Gujarat, Rajasthan are under loss. The above depends on how much gap is there between average and peak demand for a particular state.

4.17.2 Comparison of results with and without slabs

(a) Slab rates were introduced to avoid initial tariff shock during 2011. Further slabs were increased to 9 in 2015. Slabs were retained in 2015 keeping in view POSOCOs suggestion on assumptions being made while POC.

(b) Slabs facilitate in keeping the difference between minimum and maximum rate as a defined number as required by amended Tariff Policy.

(c) The beneficiary whose actual transmission charge payable rate were below a defined slab rate were scaled up to lowest slab rate and the beneficiary whose actual transmission charge payable rate was above the maximum slab rate were scaled down to pay based on the maximum slab rate.

(d) The beneficiary whose Rate was less than minimum slab rate ended paying more than software computed charge and beneficiary whose rate was more than maximum slab rate ended up paying less than the software computed charge. The beneficiary whose cost computed where in between the maximum and minimum slab rate had least impact.

(e) As number of slab rates are increased and the gap between maximum and minimum increase, it creates advantage to less transmission charge paying utility and disadvantage to higher transmissions charge paying utility.

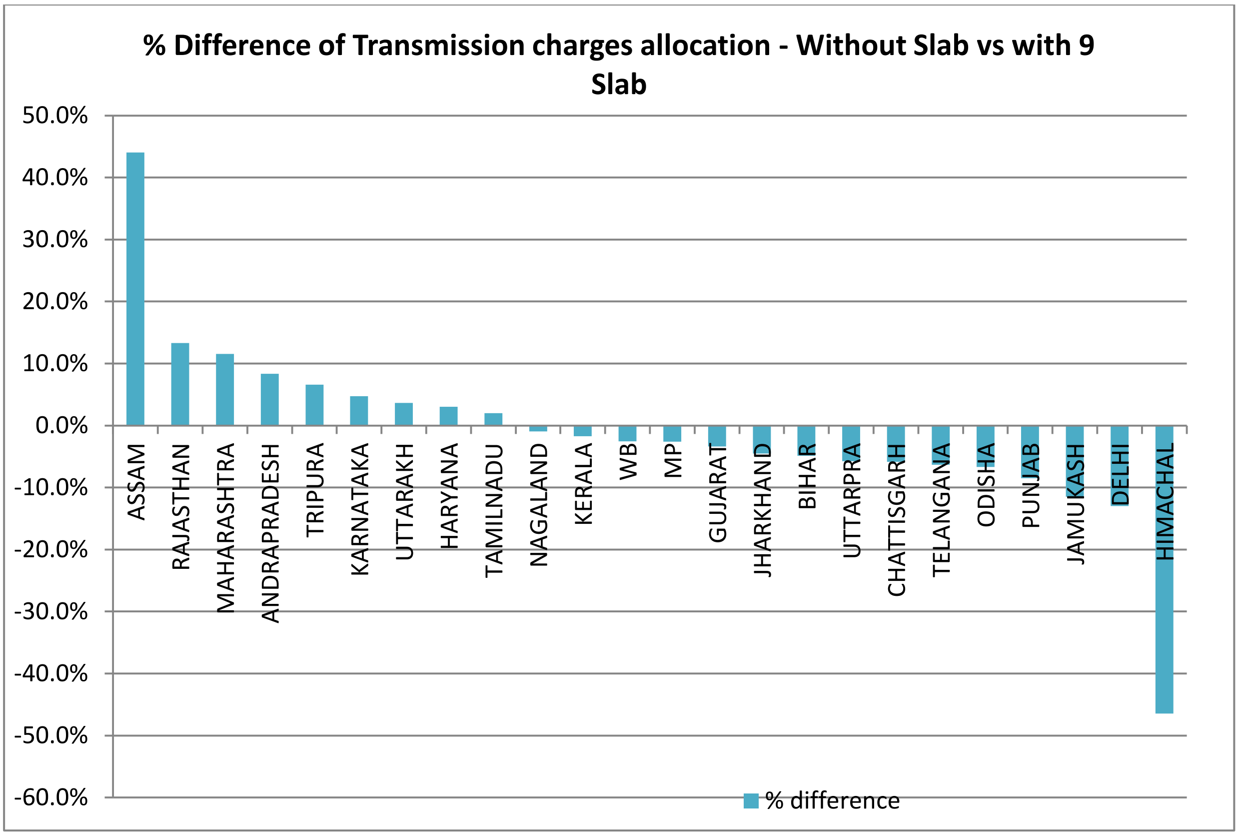


Figure 15: Percentage difference of transmission charges allocation on States without slabs vs 9 slabs

(f) It is observed from above that major benefits of slabbing is to states like Rajsathan, Assam, Haryana and loss is to Telangana, U.P., Himachal Pradesh.

4.17.3 Comparison of results with Uniform all India Postage stamp vs PoC charges method

(a) All India Postage stamp rate was determined by dividing total monthly transmission charge by LTA+MTOA.

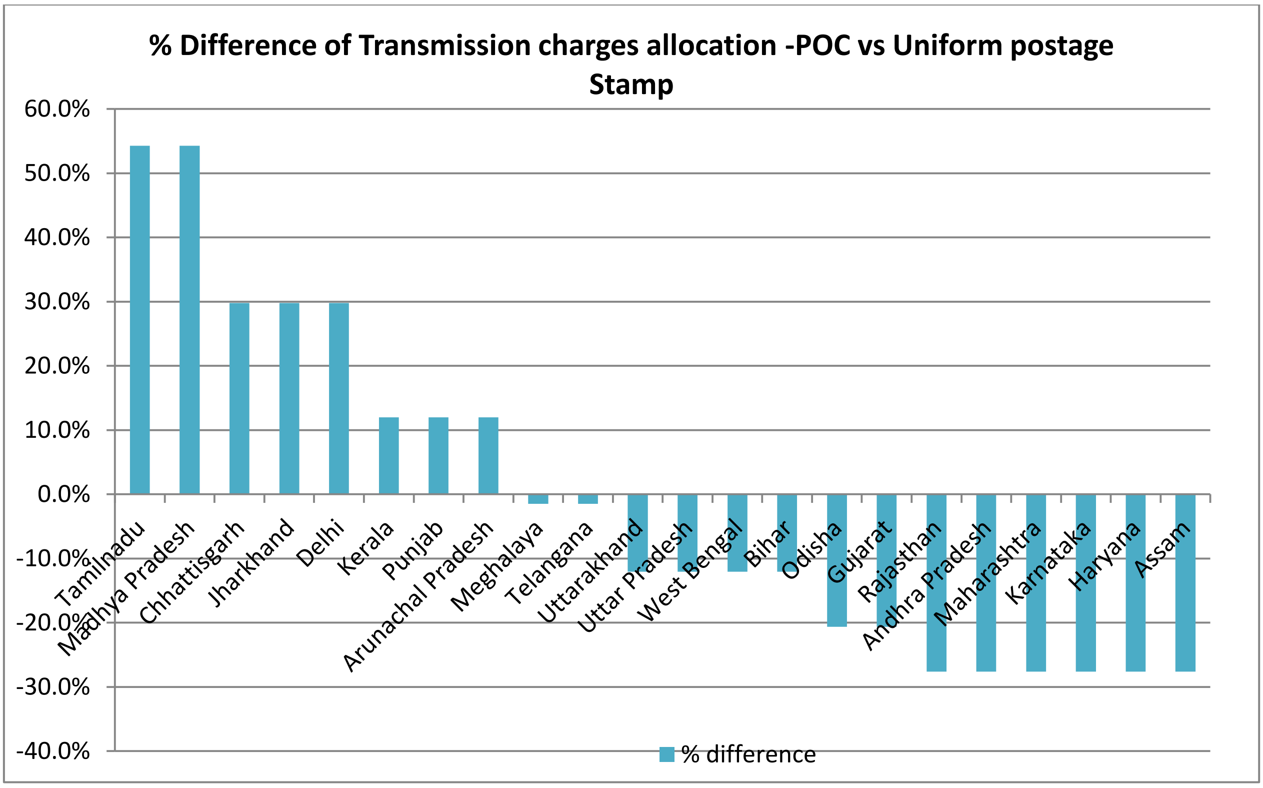


Figure 16: Percentage difference of transmission charges allocation on States under PoC vs Uniform charges

(b) In case all India average price is billed to all States, major benefits shall be to states like Maharashtra, Rajasthan, Karnataka, A.P., Haryana, Assam, Gujarat and loss is to Himachal Pradesh, T.N, M.P., J&K, Delhi

4.17.4 Identification of lines which are marginally used and its sharing based on socialisation

(a) The cost of each line has to be recovered in full as per approved tariff of CERC, irrespective of the power carried by the line. To check the impact of less loaded line on the total transmission charge paid by a beneficiary, the cost of such lines were not considered and computation were carried out.

(b) It was observed that the cost of less utilised lines were being paid by certain beneficiary as per location of the line and direction of power carried by the line.

(c) In the sample case, 400 kV transmission lines carrying less than 100 MW and 765 kV lines carrying less than 300 MW were excluded from cost allocation. The charges for these lines were socialised on all beneficiaries in ratio of their transmission charge allocation for other lines.

(d) Out of Monthly Transmission charge of approximately Rs. 2500 Crore, Lines worth rs. 783 Crore were found to be marginally utilised

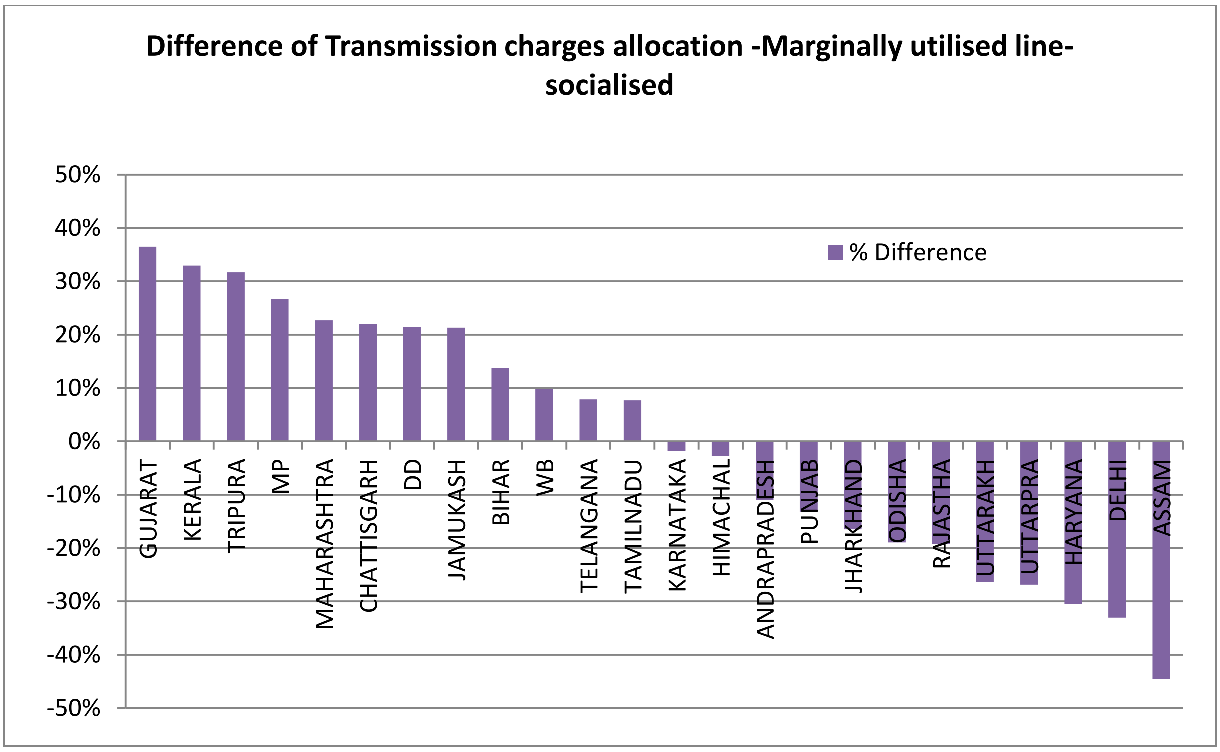


Figure 17: Percentage difference of transmission charges allocation on States under current Poc vs when marginally utilised lines are socialised

(e) It is observed from above that major benefits of socialising marginally utilised lines is to states like Rajsathan, Assam,Haryana, U.P, Delhi and loss is to Gujarat, Maharashtra, M.P, Kerala.

4.17.5 Comparison of transmission charges with 3 slabs, 5 slabs, 7 slabs, 11 slabs and 13 slabs

(a) There is a minor variation in results if slabs are reduced or increased as under:

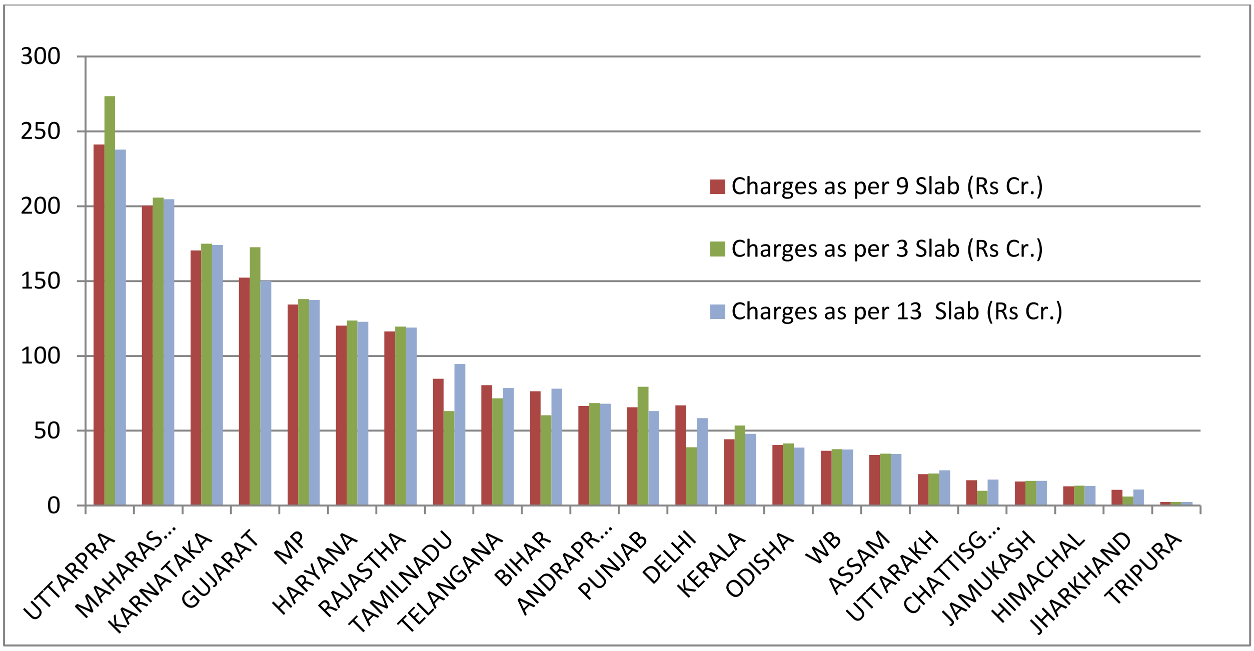


Figure 18: Transmission charges allocation on States under 3,9 and 13 slabs

4.17.6 Comparison of Actual Peak Demand vs Projected Peak Demand as considered in POC Calculations

(a) An analysis was carried out for Q1-2017-18 to compare the actual demand met vs projected data to determine the accuracy of data used. There is minor variation in the actual demand except for a few states who have been advised to provide their data prudently during validation Committee meeting of CERC.

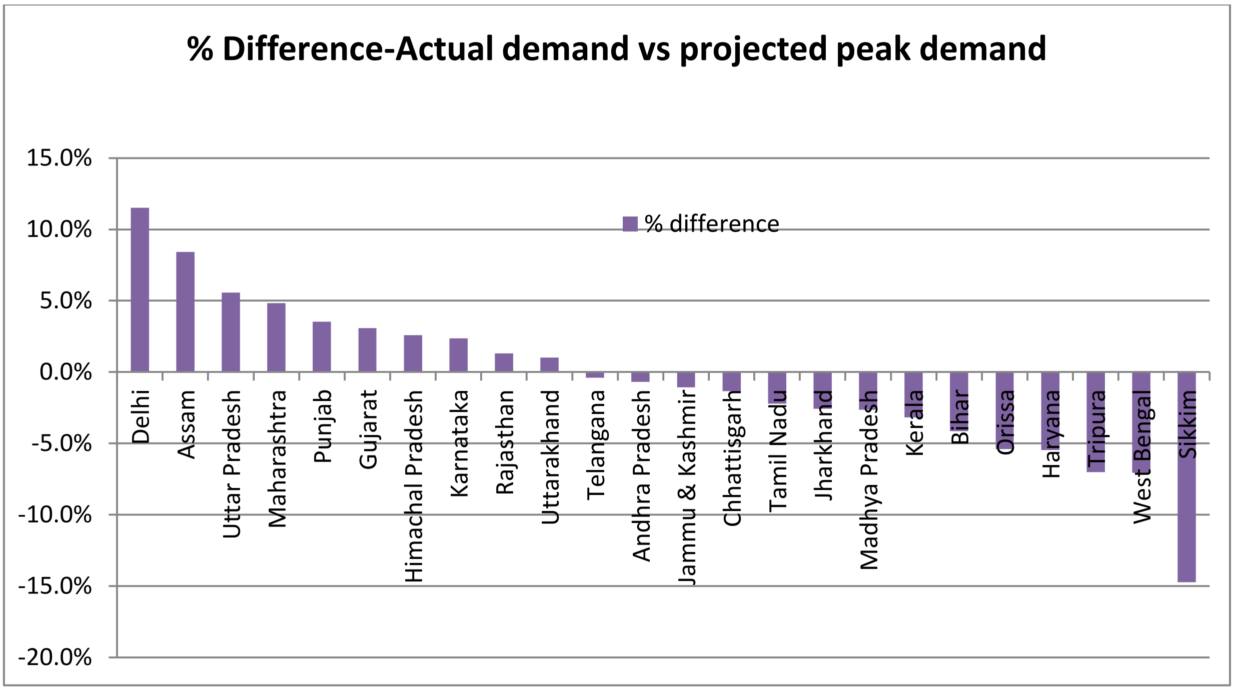


Figure 19: Percentage difference of actual average demand vs projected peak demand

4.17.7 PoC charges based on Projected peak demand vis a vis Actual Average demand

(a) NLDC carried out comparative analysis of Poc charges as per notified rates based on projected peak vis a vis based on actual average demand.

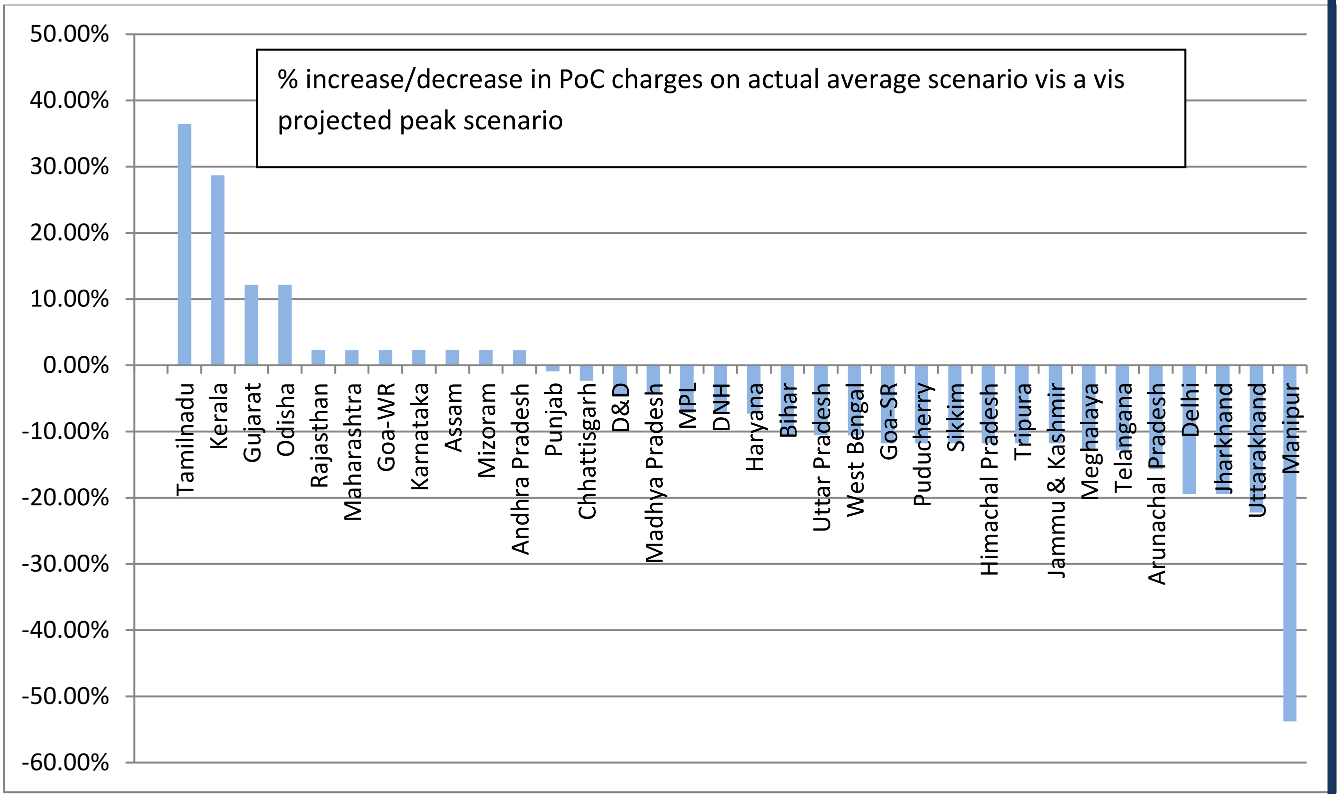


Figure 20: Percentage difference of transmission charges allocation on States under actual average demand vs projected peak demand on prevailing PoC

It is observed that based on actual average scenario , one snapshot for the quarter, charges for Tamil nadu will increase by approx 36% and that of states like A.P, telangana, U.P will decrease.

4.18 Suggestions of stakeholders for transmission pricing methodology

4.18.1 Few stakeholders have advocated that number of slabs should be reverted back to 3 or there should be all India Uniform rate. Mr. Pradeep Jindal, CEA stated that all India single POC rate (Postage stamp), results in higher(and uneconomical) investment in transmission system. (And this is the reason for CTU/POSOCO to support such concepts). It distorts the economic signal for optimum procurement of power by the States. It blurs the distance-direction philosophy of the tariff policy.

4.18.2 Mr. Vijay Menghani, CEA has suggested that weighted average of peak and off peak cases should be used explaining as follows:

(a) Few states are contesting that due to their load pattern it is not possible to flatten load curve and their usage of ISTS is less than what they have to pay. It is true that when usage or flow based transmission charges are done, taking only one scenario may not be a true reflection. So for making it representative more scenarios need to be considered.

(b) This need to be looked into but there is also demand of making POC charges computation simple. As more scenarios are included , the complexity increased , it become more fair , so a call need to be taken by all stakeholders . But for making it simple, the efficiency and fairness should not be sacrificed.

(c) In principal regulations published in study for peak and off peak period was decided and based on weighted average, transmission tariff were to be computed. It is suggested that to make it more fair two scenario study may be made. Peak and Average usage case and based on simplified weighted average .Later it was dropped as states were not furnishing required data even it was i their own interest and method of average case based on Energy was adopted . The average method was distorting as cost allocation was shifting widely from planning to pricing. It was benefiting the state for whom the system was built to cater their peak demand and liability was being shifted to other states.

(d) The proportionate and more fair approach would be give due consideration to both peak and off peak because drawl pattern form ISTS system changes in both. This has been adopted in UK where usage based almost similar transmission charges allocation methodology is adopted. Also in Maharashtra, even postage stamp methodology is used based on 50% peak and 50% Average usage.

(e) The adoption of Peak /off Peak or Peak / Average methodology is need of the hour also due to increasing penetration of renewables. Due to generation from Wind /Solar , the drawl of RE rich states from ISTS system decrease during day time so for correct representation of usage load flow study of both peak /off peak period is must and it will address problem of RE rich states. The generation from RE sources will be considered in off peak period appropriately by reducing generation from conventional source. The success of this method will depend on data given by state utility.

(f) This will also decrease the spread between minimum and maximum tariff.

(g) At present procedure depend upon submission of data by utility. In other countries like UK and Australia the computation is done based on last year snap shot as available with system operator and even five minutes cases are run . The running of as many cases as possible is recommended to allay the fears for stakeholder that they are charged for a single case while their usage at other time is less. In the comparison of many cases with actual drawal it was found that sometime states are also drawing much more than what they projected for peak scenario.If study is done on the basis of past data, while chances of data deficiency and manipulation decreases and on rolling bases usage is captured correctly.

4.19 Analysis and recommendations of taskforce for transmission pricing

4.19.1 The suggestions of stakeholders and analysis of the taskforce thereof interalia on issues like ex-ante vs ex-post, quantification of reliability component, allocation of charges based on utilisation and survey of internation practices, the Taskforce recommends two options for transmission pricing:

(i) Point of Connection based
(ii) Uniform charge based

The methodology to be followed for each of the options is described in subsequent paragraphs:

4.19.2 **Point of Connection charge based**

(a) This methodology shall have four components of transmission charge viz (a) Point of Connection charge (b) Reliability charge (c) Residual Charge (d) HVDC charge. Each component is described in subsequent paragraphs

(b) Point of Connection charge based method

I. Preparation of base case

(i) Mr. Vijay Menghani, CEA has submitted as follows:

"

a. After analyzing data considered by implementation agency and actual operation for the period Q12017-18, it appears that many states are trying to giving lower estimate of their drawal from ISTS. This is resulting in wrong computation of POC for every DIC.The important data for POC computation is not the peak demand of state but how and on which drawal points DIC want to draw from ISTS. At present by giving higher figures of own generation and lower figures of demand , deliberate effort is made to show less drawls from ISTS. CERC and implementing agency should look into this aspect.

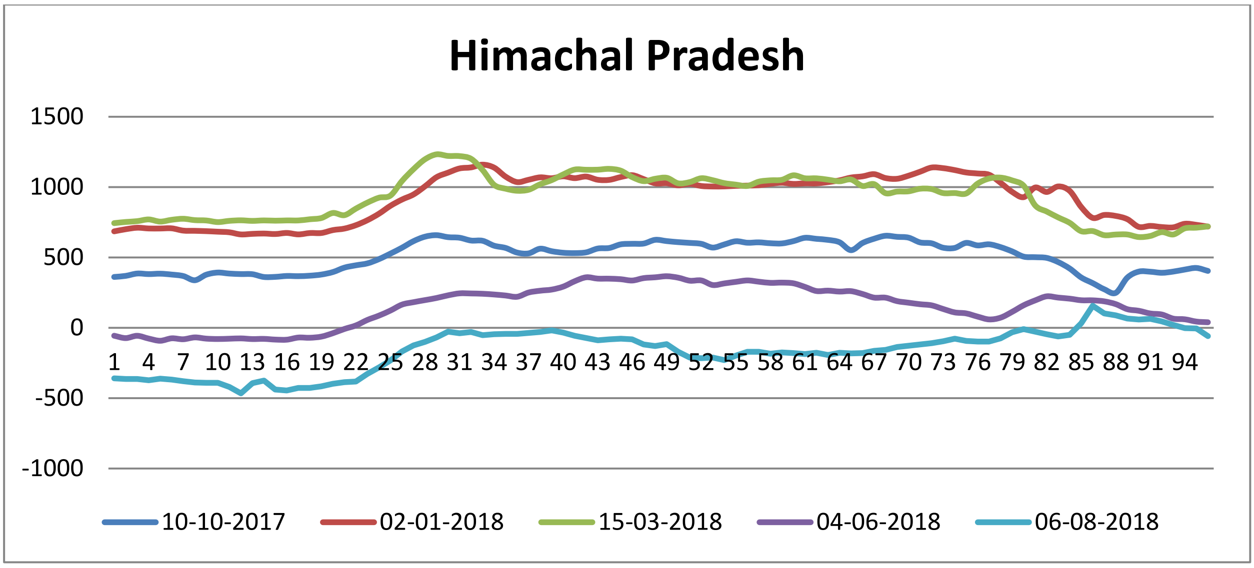
b. Also drawls pattern of few states is quite different from peak scenario of country. For example in case of Rajasthan, its drawls from ISTS was maximum during morning hours in place of evening. This aspect need to be captured as objective intention is to compute usage of ISTS. The actual usage is more than 10 to 15% than projected. Actually linking billing with LTA is also gives lot of leeway to states. The transmission charges calculated on the basis of projected drawal should be billed and then for additional drawal states should be billed under deviation . By calculating on lower forecasted figure and considering this for upto LTA , results in benefit to states who under forecast.

c. For charging based on actual usage, datum should be usage considered in load flow and then if drawls is more than that under deviation transmission charges, billing should be done. At present by using LTA as a datum this account is more or less defunct and states drawing more than projected demand are not paying anything.

d. The base case preparation is very crucial for determination of correct transmission charges to be paid by state utility. CEA , CERC and POSOCO should prepare a guideline how best it can capture utilization of ISTS by state utilities keeping in view the utilisation of ISTS by different users."

(ii) Analysis of taskforce for preparation of base case

a. We have perused typical blockwise ISTS drawal for a typical day for a few select States as follows:


Himachal Pradesh
1500
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-500
-1000
1 4 7 10 13 16 19 22 25 28 31 34 37 40 43 46 49 52 55 58 61 64 67 70 73 76 79 82 85 88 91 94
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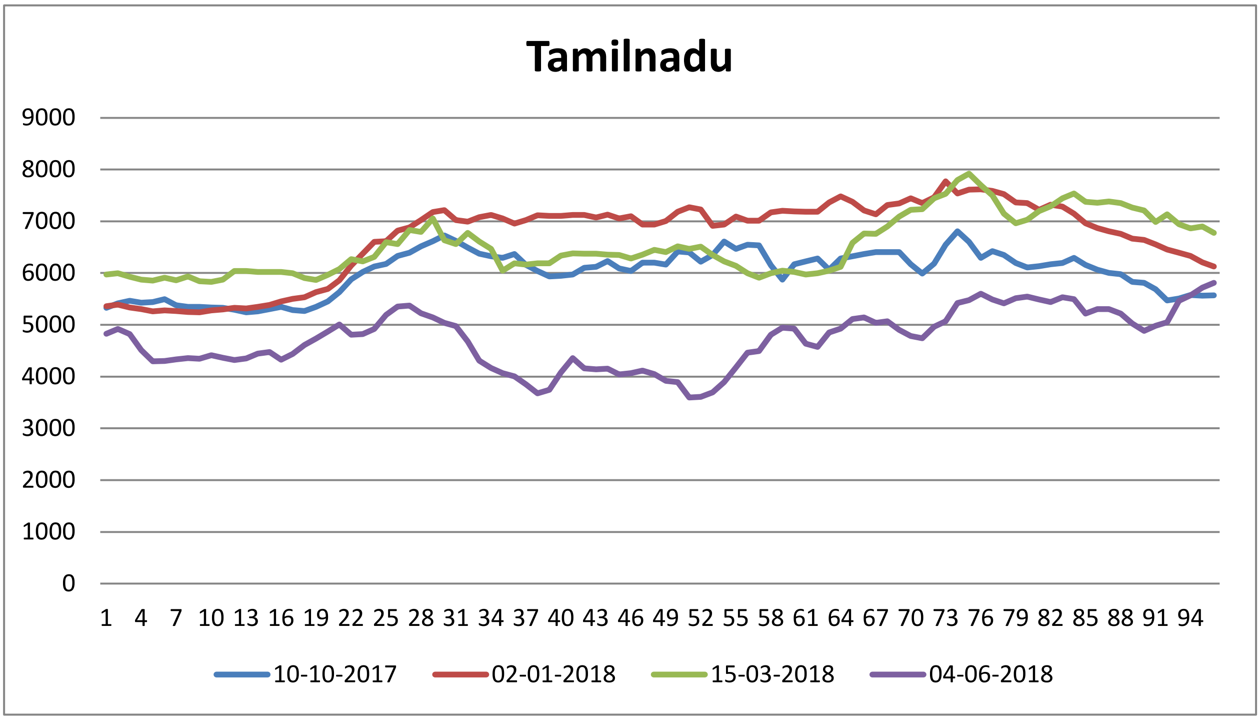
02-01-2018
15-03-2018
04-06-2018
06-08-2018

7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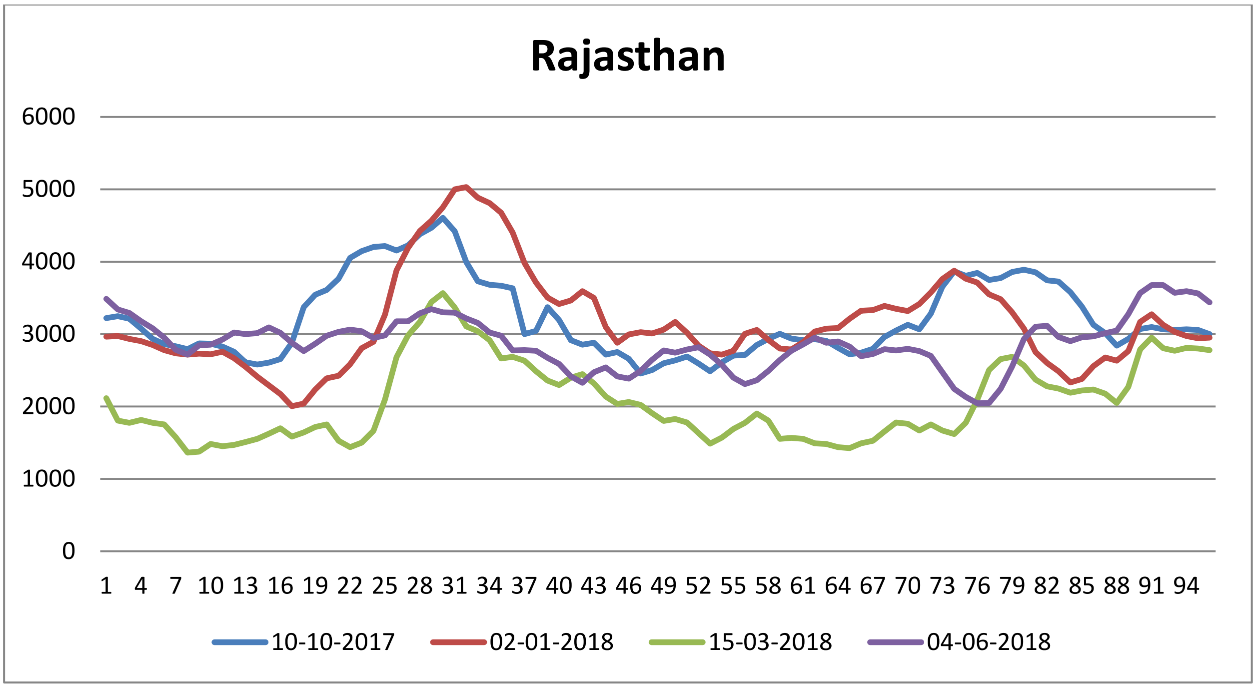
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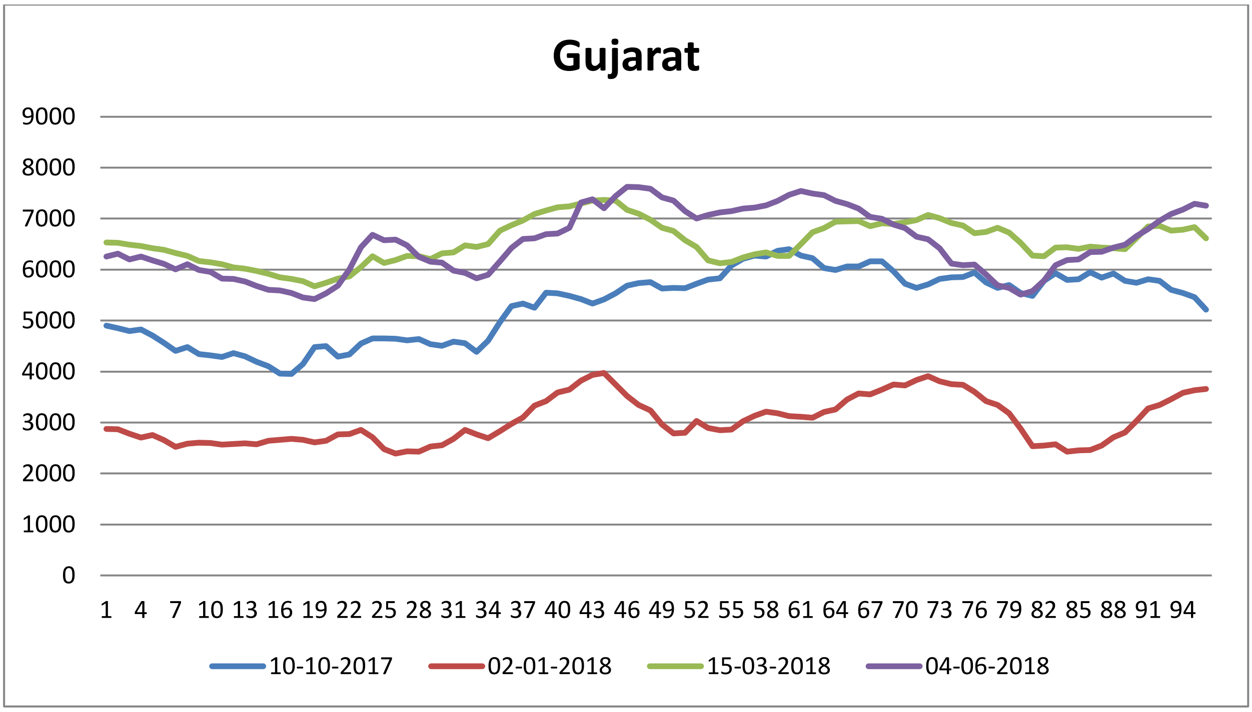
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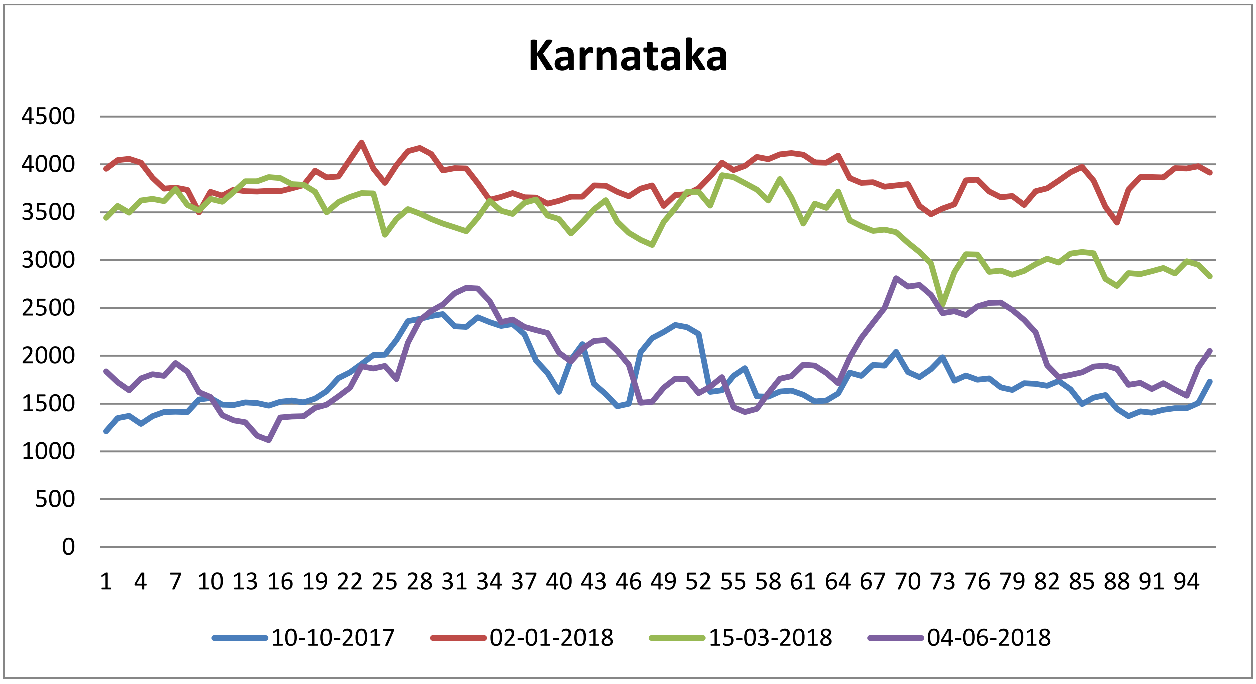


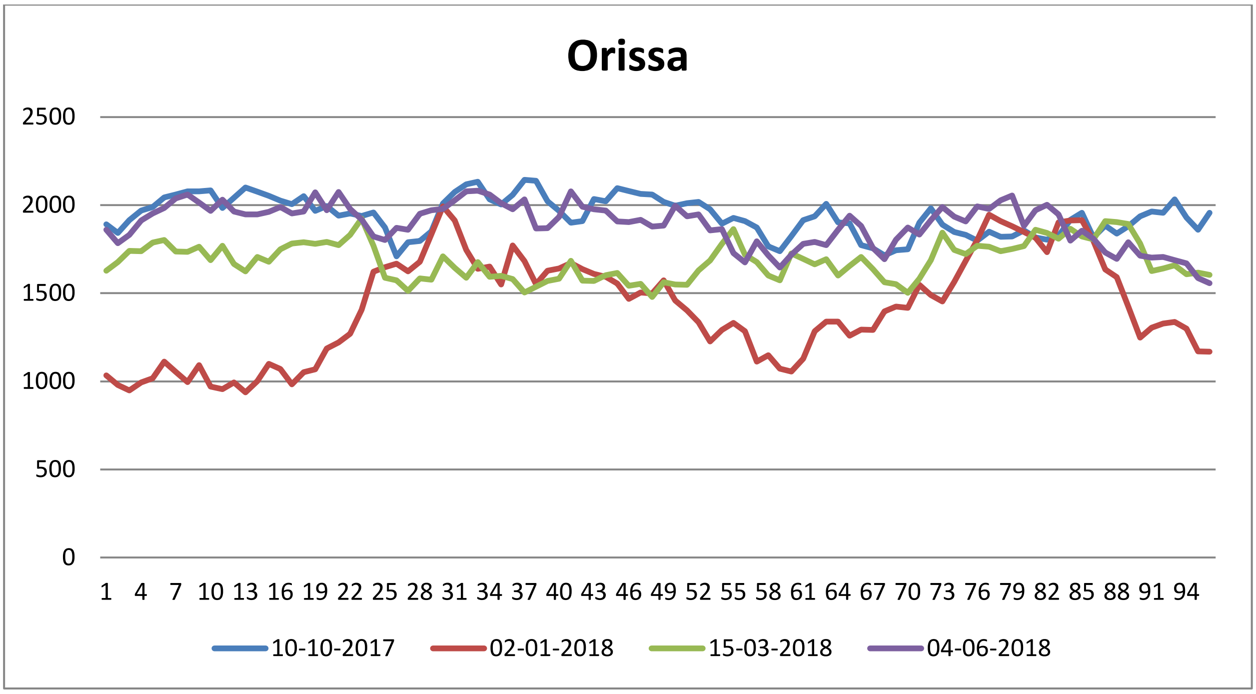


Figure 21: ISTS drawal of States for a day for select dates for select States

b. It is observed that ISTS drawal varies over a day. For example for Orissa ISTS drawal varies from 1000 MW to 2000 MW over a day.

c. To determine actual usage of ISTS lines, blockwise actual data for ISTS drawal may be considered to determine the applicable charges under usage component.

However there may be issues with running the software for everyblock. Till the time systems are built to run the software for every block, a monthly peak scenario based on actual ISTS drawal may be considered. Monthly peak means the block in which monthly All India peak demand is experienced. The Actual ISTS drawal /injection for all entities for such a case should be captured.

d. NLDC has provided feedback in Validation Committee meetings that States are not providing nodewise data as required vide Sharing Regulations. It is also observed from the availability of data telemetry that data of nodes within States are not available completely. Once the base case is prepared on actual scenario, nodewise actual data would be required for preparation of the base case. However it is observed that transmission charges of ISTS is supposed to be allocated to entities through these Regulations. All such ISTS interfaces are metered and monitored by POSOCO for which actual data is available including the reactive power component of such data. Hence simulation of ISTS network on actual data is most accurate, feasible and practical option.

e. The DICs should provide data for intra-state points accurately as per actual. The base case file shall be prepared so as to get the actual load/generation for ISTS points and corresponding data for intra-state network should be provided by DICs . However in absence of such actual data for intra-state points, the data for such intra-state points shall be included in simulation, so as to approximate the actual drawal/injection at ISTS interface. This is subject to necessary adjustment required for load generation balance.

II. Percentage of Monthly transmission charge to be considered for base case

(i) Mr. Vijay Menghani, CEA has submitted as follows on Underutilised lines and approach to recover their tariff

a. It is being stated that as due to less than expected growth of demand , flow in line is much less than its capacity , the utlisation of ISS is 35% , so i place of recovering full charges through flow based POC method , only 35% may be computed using POC and rest should be allocated to all on postage stamp method.

b. This suggestion is very much against the principle of Tariff policy and not only it will affect distance direction and usage sensitivity, it will transfer the burden of unutilized lines to those DICs who have no role either in planning and construction of these lines nor they are responsible for under utilization of line.

c. It may be mentioned that usage of line is being defined very narrowly. Only power flow cannot be termed as usage of line. It must be kept in mind that transmission system is a “LUMPY “ investment i.e a line can be of 220 kV , 400 kV or 765 kV and are being constructed through an integrated planning process considering usage for next 25 years .It can not be built for incremental use of 1 MW.

d. In addition to this during planning process , reliability of transmission system need to be ensured for all scenario and possible contingencies. With six scenario study and considering N-1 contingency as mentioned in Planning criteria and Grid code, a transmission system will be built where flows would always be less than line capacity for majority of line and no line would be overloaded except for small duration under contingency..

e. The system usage in other countries is also of the same level and in many it is less than 35%.. So saying line is under utilised w.r.t. Its capacity is not a correct statement. The line is providing additional margin due to its lumpiness, provide adequacy and reliability under contingency and most important it provide economic value by facilitating import of cheaper power.

f. YES, there may be some lines which are grossly underutilized due to some external reasons like relinquishment by generators. This is a problem area because even a small flow /change of low on this line burden a DIC unnecessarily and this problem need to be addressed, but for solving this all the efficiency of methodology should not be sacrificed.

g. Professor Ignacio J. Pérez-Arriaga , original proponent of marginal participation method suggested that as for new lines utilisation in initial period is less than average, it should be decided based on average utilisation of similar capacity line.

h. So in case of our country If it is much less than say 35% , it can be considered as under utilised.

i. It is understood that as per a study by CERC transmission lines having tariff of rs 827 crs are underutilised, that corresponds to almost 25%. The load flow of Q1 2017-18 was examined in detail ,it was found that this estimate is on higher side. Underutilised lines need to be defined/ segregated in a different way.

(i) Underutilized due to change in flow pattern : Some of ATS of gas based generating station is underutilized because power generation from gas is not being scheduled. This should not be considered as under utilised.

(ii) Under utilised due non commissioning of hydro generating stations in NER: The ATS for Kameng and Subansiri is underutilized due to delay in hydro generating stations due to environment reasons. These assets are heavily burdening NER region. For example 400 kV Bongaigaon Baripara quad with 30% FSC is resulting in almost 35% transmission charges for NER. Considering special status of NER a policy decision need to be taken and these can be shared through a pool mechanism.

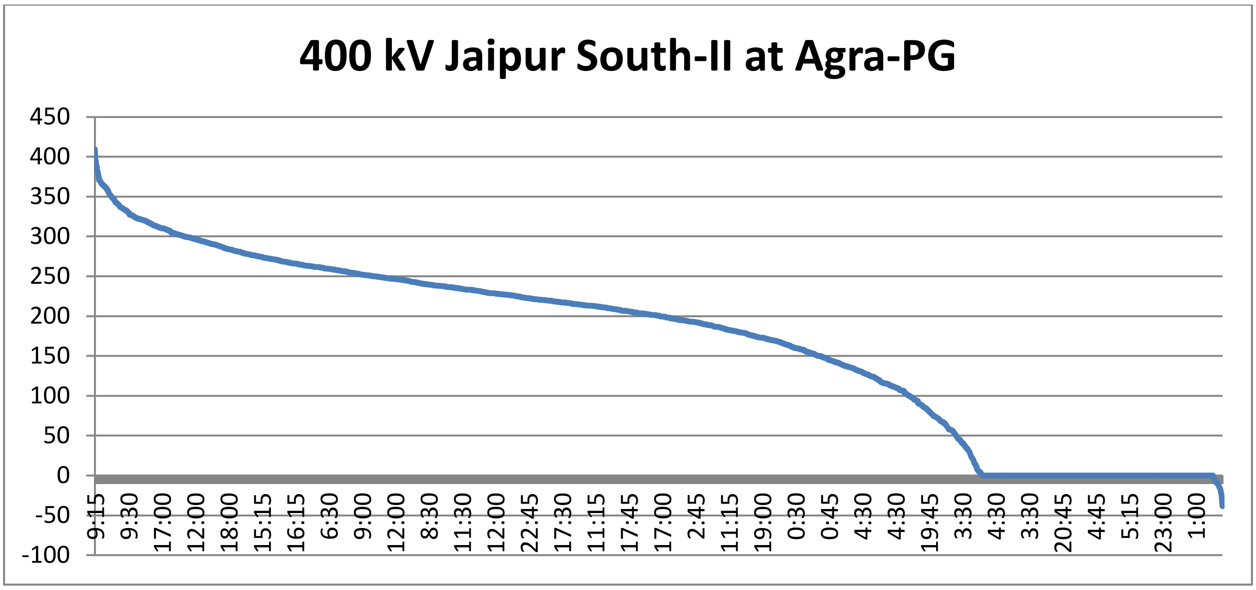
(iii) Underutilized assets of HCPTC corridors: This a major problem area. Due to various reasons many generators relinquished their LTA and line constructed under these schemes are burdening unintended DICs. This problem need to be resolved quickly through planning and regulatory action so that utilization of these lines can be increased and generator for whom it was build are made liable to pay these charges. Till then, a policy based mechanism like debt service through PSDF, return dilution, asset shifting and tariff pooling need to be formulated and these lines can be kept out of POC computation. The charges for the same can be recovered under a separate head and billed under POC mechanism. It is proposed that same may be recovered by raising STOA charges.

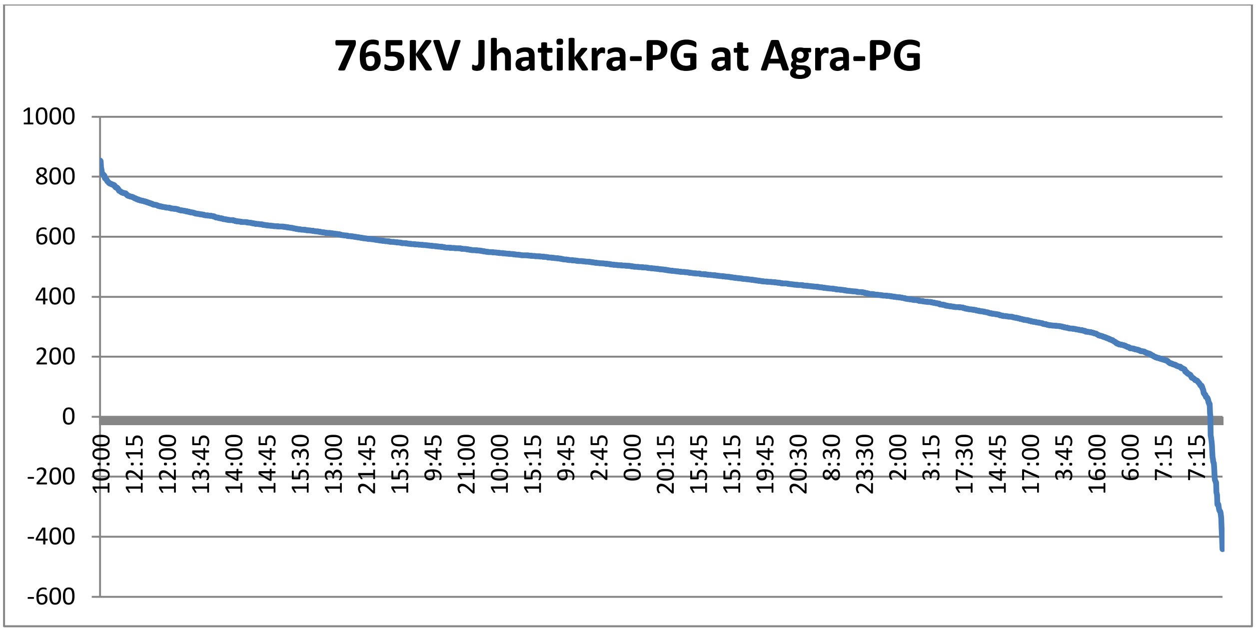
(iv) Also after examination of data collected from CERC and from POSOCO website it was found that line utilization changes not only season to season but within the day itself. In case of one state its ISTS drawl during peak was 2500 MW against projected drawal of 1700 MW and during early hours of morning it was reaching upto 4000 MW. So if early morning lad flow is done (which persist for days together) , utilisation of many lines undergoes a change.

j. Suggestion There was a proposal to treat almost 65% line capacity as unutilized and billed through postage stamp. We do not agree with this. Any attempt to bifurcate a line utility as utilized and unutilized is not in line with how planning of infrastructure assets is done. As already stated postage stamp method is an inefficient mechanism and it has many externalities like transfer of burden of charges from actual user to all members of pool. Just because for a planning period demand as projected initially did not materialize, all the efficiency gain of modern method of transmission pricing should not be sacrificed.

(ii) Analysis of the taskforce with respect to monthly transmission charges to be considered in base case

(a) We have perused typical flow of a few transmission lines based on actual data obtained from RPC and RLDC for ISTS. The flows are blockwise data for month of January 2019.The following represents flow duration curve for the line.





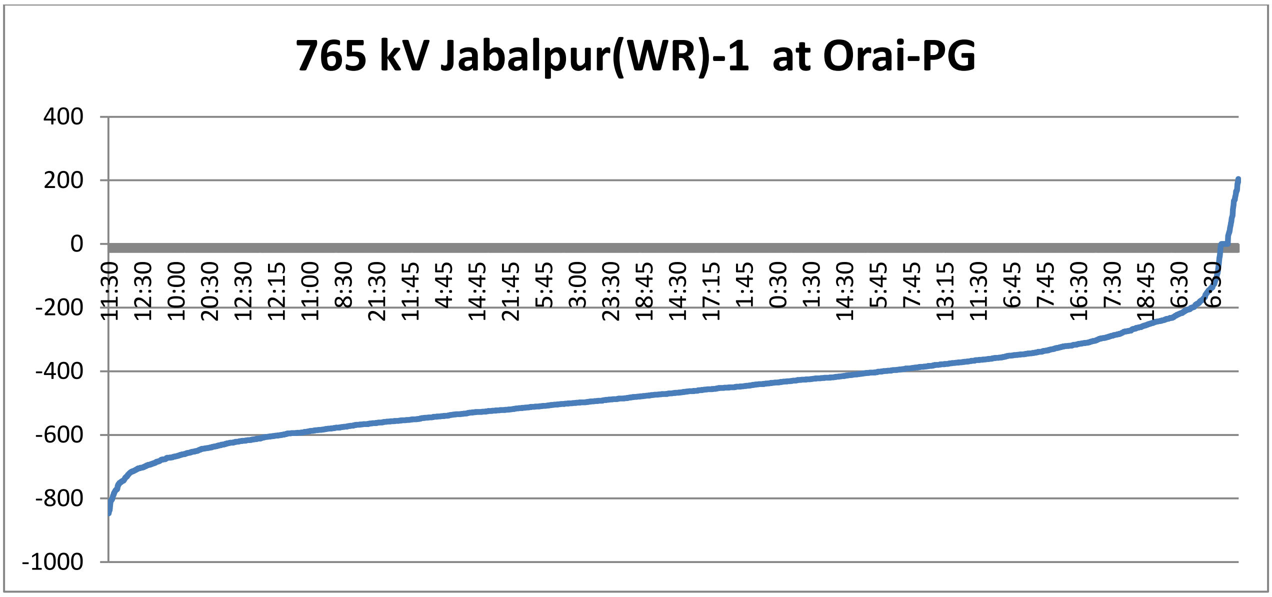


Figure 22: Load duration curve for select lines for January 2019

(b) It is observed that utilisation of lines varies over a day and over the year. Since PoC methodology allocates charges based on utilisation, percentage utilisation for each line may be determined and MTC corresponding to such utilisation for such line should be considered in the base case as per its utilisation. To determine this component, the flow in the line in the base case as prepared above should be captured and should be divided by loadability of the line. The loadability of the line shall be considered as per CTU website as used under ATC/TTC assumption. A sample of such Assumption on CTU website as "Major assumptions/observations for declaration of TTC/ATC for Apr'18 to Jan' 19 issued on 05.01.2018" is quoted below for clarity:

"3. The limit of various 765kV Inter-regional corridors between WR & NR has been considered as 3000MW under n-1 condition after commissioning of Jabalpur – Orai – Aligarh 765kV D/c corridor between WR & NR. Limit of Aurangabad – Solapur – Raichur 765kV corridor has been considered as 2750MW per circuit under N-1 contingency. Limit of all other 765kV lines has been considered as 2500MW under N-1 contingency. The loading limits of all the 400kV lines are the thermal limits."

III. Modifications in present PoC method-Modified PoC method

i. Computation of PoC to be carried out Ex-Post on monthly basis based on actual scenario. Actual All India peak scenario for the month shall be taken.

ii. This methodology suggests to have four components of transmission charges viz (a) Point of Connection charge (proportional to actual MWs drawn/injected blockwise during the month) (b) Reliability charge (based on non-coincident peak demand during a month) (c) Residual Charge (based on contracted capacity LTA+MTOA during the month) (d) HVDC charge.

iii. The MTC for the entire AC system (for each line) excluding lines identified under renewables (with waiver of charges) shall be divided into three components viz.

1. POC portion: based on ratio of Base case flow in the load flow corresponding to the All India peak scenario for the month and loadability as per CTU website used for TTC/ATC.
2. Reliability Portion –based on difference between base flow corresponding to the All Peak Scenario and the maximum flow observed for the (n-1) contingency divided by loadability.
3. Residual portion - which is balance of the charge for each line after deducting POC and reliability portion.

iv. The above three portions shall be shared amongst the DICs in the manner as described below:

1. POC portion: This portion shall be shared by each DIC corresponding to the actual utilisation of ISTS in each 15 minutes block. The same shall be

arrived at by multiplication of blockwise POC rate (as derived from Webnet software) by actual MW in a given time block.

2. Reliability Portion – This portion shall be shared by each in DIC in the ratio of non-coincident Peak power drawn/injected during to the month to the sum of non-coincident Peak power drawn/injected during to the month.
3. Residual Portion – This portion shall be shared in ratio of LTA/MTOA of each DIC and the total LTA/MTOA on All India basis in the ISTS. For generators this shall be taken as untied LTA as being done currently.

v. To arrive at the POC rate, the zonal charges determined for All India peak scenario for the month shall be divided by an entity's ISTS injection / drawal at that block. There is no need for put these rates into slabs. There may be 40-50 such rates depending upon the number of ISTS payers in the grid.

vi. The charges shall be determined ex-post i.e based on actual scenario. Actual All India peak scenario for the month shall be taken. The actual data at ISTS points is available with POSOCO. The base case file shall be prepared so as to get the actual load/generation for ISTS points and corresponding data for intra-state network should be provided by DICs . However in absence of such actual data for intra-state points, the data for such intra-state points shall be included in simulation, so as to approximate the actual drawal/injection at ISTS interface. This is subject to necessary adjustment required for load generation balance.

vii. It may happen that an entity was injecting / drawing less at time of All India peak. It is also observed that injection / drawal varies in every block. An entity's PoC rate shall be multiplied by its actual injection/drawal for each block. Due to billing on actual blockwise MWs, there may be over or under-recovery of MTC for PoC portion based on DICs drawal/injection during All India peak vis a vis its blockwise drawal/injection. Any over or under-recovery shall be adjusted from next months' MTC.

viii. HVDC

The HVDC except back to back HVDC or the one declared as National asset shall be shared on causer pays principle as being done currently and shall not be part of uniform charge or modified PoC charge. The HVDC charges shall have % reliability component which shall be equivalent to the % reliability component as derived for the entire AC system. The reliability component of HVDC charges shall be added to reliability component for AC system and shared on the basis of non-coincident peak.

4.19.3 Uniform **Charge** based

(a) Few states have contended that transmission charges should be shared based on uniform rate. There should be minimum variability and that transmission charges sharing should be easily understandable. That the current mechanism is complex.

(b) Keeping in view the suggestions, the taskforce suggests and alternate formulation based on uniform rates as follows:

(c) All India Monthly transmission charges (excluding transmission system identified for renewables who are availing waiver of transmission charges) shall be divided by Average ISTS drawal / ISTS injection for all entities. All entities imply entities to whom transmission charges are to be billed. This will not include generators whose full /part capacity is tied up under long term PPA. For generators this quantum will be considered as contracted LTA capacity which is not tied up under PPA. The Average ISTS drawal/injection shall be determined by taking average of 15 minute blockwise data for the month for each entity. For states which inject in ISTS in while calculating the average their injection will be considered as drawal and average MW will be arrived at.

(d) For billing, the uniform rate (Rs./MW/block) shall be multiplied by actual ISTS drawal/injection for states. For generator, the billing shall be based on Uniform rate X contracted capacity not tied up.

(e) In Uniform rate methodology is adopted, augmentation done for renewable projects (systems specifically created considering renewable generation) should be separately listed. The MTC for such system should be allocated to all entities in the ratio of their contracted capacity (LTA+MTOA).

(f) The treatment of HVDC (except back to back) shall be as per current methodology of "causer pays" principle. No reliability component shall be deducted from such HVDCs since no separate component of reliability shall be calculated under this method.

4.19.4 Other **suggested options**

(a) Few members of the taskforce have suggested additional options as follows:

(i) Ms. Manju Gupta, suggested an option as "Hybrid Uniform Charges method" as follows:

"

1. While calculating uniform charges based on only energy drawl, following issues have been raised :

- LTA is granted in terms of peak power flow (MW) not in MU and LTA granted is predominantly the basis of Transmission planning in India. Therefore, Investment required are generally not a function of the amount of energy generated or consumed, but rather the amount of new generating capacity connected to the grid or the peak demand of consumers

- In MU based tariff, it is not possible to keep track of the violation of the LTA limit (MW)
- Tariff calculation for future transmission system is difficult as MU consumption cannot be anticipated. Monthly rate would vary due to changes in MTC and Energy drawl, leading to volatility in transmission charges payable by Discom.
- In MU method, transmission tariff during off peak conditions may become very less compared to actual investment towards transmission infrastructure.
- Transmission System is used for both injection and drawl. Uniform Rate for net drawl/injection does not consider full usage of Transmission System by beneficiary.

2. To overcome above, an alternate formulation based on hybrid uniform rates – partly based on energy and partly based on contracted capacity is suggested:
3. The weightage of these two parts may be considered as 50: 50 or 40 (usage): 60 (contracted capacity). Alternatively, after making calculations in option 1 i.e. modified POC Method, the percentage of transmission charges allocated based on utilization and Reliability may be recovered through uniform charges based on usage i.e. MU. The balance percentage of transmission charges (corresponding to Residual Charges) may be recovered through unform charges based on contracted capacity. In Uniform rate methodology is adopted, augmentation done for renewable projects (systems specifically created considering renewable generation) should be separately listed. The MTC for such system should be allocated to all entities in the ratio of their contracted capacity (LTA+MTOA).

(iii) Chief (Engg.) has suggested an additional option as modified Uniform charges proposed above as detailed below:

"

- Transmission system is planned based on LTAs duly considering redundancies, system contingencies maximum or peak capacity to be transmitted and other reliability criteria. Apart from these system is also planned considering future requirements on account of right of way issues or technology considerations. A transmission system is thus generally planned for a capacity which may be higher than the LTA capacity. Further, transmission system does not operate at its full LTA capacity all the time and thus average usage or the peak usage are much lower than the actual capacity planned. The balance capacity could be related to the reliability of the system to meet the credible contingencies. Any additional capacity for meeting future requirements also adds to the system reliability.

- In the light of above, sharing of transmission charges could be in two parts. First part in the nature of fixed component to be shared proportionate to the respective. LTAs irrespective of usage and the second part in the nature of variable component to be shared in proportion to average usage preferably or the peak usage.

- From the last five year data of actual flows through the lines, average flows in the lines may be captured as a percentage of the line capacities. As such, the variable component shall be set at this average percentage of the monthly transmission charges which may be shared in proportion of actual average drawals of the month of respective DICs. The fixed component shall be balance percentage of the monthly transmission charges which may be shared in proportion to the respective LTAs of the DICs. Value of fixed component and variable component may be reviewed from time to time.

4.19.5 **Comparison of PoC (beneficiary pays) vs Uniform method**

(a) William W. Hogan in its paper titled "Transmission Benefits and Cost Allocation" dated May 31 2011 has stated as follows:

"The attraction of the principle that the beneficiaries pay for transmission investment has dimensions of both fairness and efficiency. The fairness criterion is important especiallybecause the cost allocation principles apply to mandated transmission investments thatexploitthe power of government to compel participation. The emphasis here, however, ison the effect of cost allocation principles on the efficiency of electricity systemframework. Absent a beneficiary-pays principle, it would be difficult to maintain amixed system of voluntary and mandated transmission investments, or provide efficientincentives for generation and load that in part compete with and in part arecomplementary to transmission. For particular investments, beneficiaries that might beprepared to agree to voluntary cost allocations would have strong incentives to prefermandated investments if the mandate were to shift the cost in part to those who do notbenefit. Similarly, socialization of the cost of transmission would create the demand foroffsetting socialization of competing load and generation investments. However, if theeffect of mandated investments were to allocate the costs to beneficiaries, there would bea reinforcement of the incentive to proceed with voluntary arrangements. Therefore, theprinciples for mandates transmission expansion and cost allocation stand at the center ofthe structure for electricity market design".

(b) While beneficiary pays seems more fair and efficient but the complexity to determine who is beneficiary may affect the acceptance of these methods. On the other hand it may appear that with Uniform rates, transmission investment will be easier and acceptable by all since all share the cost, the results can be counterintuitive where an entity who will not benefit by such investment may oppose such investment because it will also have to share the cost. This is stated by Hogan in its paper.

(c) Further Scott Burgera, Ian Schneiderb, Audun Botterudb, and Ignacio Pérez-Arriaga in their paper titled "Fair, equitable, and efficient tariffs in thepresence of distributed energy resources" dated August 2018 have stated as follows:

"Some power sector stakeholders – primarily select consumer advocates and trade groups – haveadvocated for maintaining today's largely time invariant and volumetric2 tariffs. These stakeholdersargue that efficient prices will be fundamentally unfair and/ or inequitable, arguing that efficient tariffswill have undesirable bill impacts for certain classes of consumers (e.g. low-income, fixed-income, orrural customers) (AARP et al. 2010; Southern Environmental Law Center et al. 2015; Solar EnergyIndustries Association et al. 2017; Alexander 2010). These stakeholders argue that today's temporal andlocationally invariant tariffs protect vulnerable customer groups. Moreover, they argue that at-riskcustomer groups will not be able to respond to efficient prices and would face higher and more volatilebills as a result (Alexander 2010). Others take a more precautionary approach, noting that, because realtime pricing may harm some vulnerable customers, real time pricing should be offered with caution andonly to certain groups (Horowitz & Lave 2014).

Focusing primarily on time varying versus flat3 rates, many scholars have noted that today's flat tariffs are inequitable, as they imbed cross subsidies between customers that consume more power during high price hours and those that consume less (Simshauser & Downer 2016; Faruqui 2012; Hogan 2010; Faruqui et al. 2010). In the short term, these "expensive" customers pay less than their cost of service, while other customers pay more. In the long term, customers that tend to consume at times of high system demand drive greater need for investment in system infrastructure, which drives up costs for all users

…

While network costs are driven in the long run by the need to develop network infrastructure to meet peak injections and/ or withdrawals, the costs of existing network infrastructure largely do not change in the short term with the amount of energy consumed or produced (Borenstein 2016; Pérez-Arriaga et al. 2016). Differences in energy prices at different locations in the network can recover only a small fraction of network costs due to the significant impact of a variety of non-convex costs and constraints, including:

- regulatory, political, engineering, and environmental constraints on network investment decisions;
- the discrete nature of network investments; and
- economies of scale (Pérez-Arriaga et al. 1995).

In areas of growing demand, peak-coincident demand-based charges, that is, charges as a function of anetwork user's demand during times of peak network utilization, can improve economic efficiency bysignaling a network user's contribution to future network costs (Pérez-Arriaga et al. 2016)."

(d) The paper concludes that the tariffs necessary to enable socially beneficial customer stratification are more equitable across many dimensions than today's flat, volumetric tariffs. By reducing cross subsidies of marginal costs and cost shifts of residual costs between customers, efficient tariffs are more"allocatively" equitable. In addition, this chapter highlights that, within a set of reasonable assumptions, it is possible to improve the efficiency of electricity tariffs without sacrificing allocative equity. Should regulators or policy makers wish to mitigate all potential distributional impacts, means-tested, minimally-distortionary rebate programs can protect vulnerable customers without sacrificing efficient signals for the remaining mass market customers.

(e) In Uniform charges few entities will cross subsidise other entities which may not be an equitable approach.

(f) Professor Ignacio in its email dated 13.2.2019 to Member convenor of the taskforce have suggested as follows:

> "What are the signals that matter in order to achieve efficiency? Get rid of the residual charges in the efficient signals and take them outside of the tariff or, if in the tariff, with some format that does not (or minimally) distort the efficient signals. Finally, pay attention to fairness, social perception and politically correct issues and make any necessary adjustments, trying to distort the economic signals as least as possible. This does not mean that you have to throw away the prior work that has been done in transmission. Transitions have to be transitions, not drastic or announced changes. But keep in mind the objective: i) realize that transmission is a small part of the electricity cost for the end consumer; ii) the only practical effect of a locational signal in transmission charges is the location of new generators (and perhaps the retirement time of some old ones); iii) in order for the locational signals to be effective, they have to be announced before the plant makes the decision to locate anywhere and they must be announced for a significant period of time (e.g. 7 years). Otherwise they are totally useless (my Irish colleagues when I was a regulator there paid every year a substantial amount of money to hire the best consultants to recalculate each year the transmission charges based on the latest information; a very dumb idea); iv) your method, based on "reasonable measures of usage" is probably roughly signaling correctly that location of new generators, since it is more or less rightly indicating the congested areas to export and the congested areas to import, although, with the "new mindset", what matters is the responsibility of the agents in causing further costs and not that much how much they are using the present costs. The results of both approaches align (although the specific values can differ) if heavy utilization coincides with the existence of congestion. They do not if there is no threat of congestion that will need further investment.
>
> For a huge country like India, and if the States have jurisdiction on how to implement the charges internally in the tariffs, it could make sense the "hierarchical approach" followed in the EU, whereby some method based on use (for the existing assets and minor new reinforcements) or in allocation based on some estimation of beneficiaries (a detailed methodology has been developed for this) is used to allocate the cost of the EU transmission network to the countries. In a second step, the countries decide individually how to allocate the cost of transmission to the different agents and to reflect it in the tariffs. Only very generic guidelines are given at EU-wide level to do this second step. "

(g) A very cautious approach needs to taken while adopting uniform charges which may seem to be less complex, but is unequitable and may lead to issues with future investments.

4.20 Transmission pricing under GNA

4.20.1 One of the TORs of the Taskforce is to recommend changes due to GNA approach of transmission planning. We observe that draft CERC(Grant of Connectivity and General Network Access to the inter-State transmission system and other related matters) Regulations, 2017 was notified on 14.11.2017. The draft had proposed a methodology of transmission sharing in its Explanatory Memorandum as follows:

"

2.2 Sharing of Transmission Charges under GNA

2.2.1 The sharing of transmission charges under GNA mechanism for transmission panning shall be similar to the prevailing mechanism provided under the Sharing Regulations. The Committee in its report submitted to the Commission has also observed the same. The relevant portion of the report is extracted below:

"6.10. Sharing of transmission charges under GNA

(a) The outline of the proposal for Connectivity, GNA, sharing of transmission charges, etc. is presented below for sake of clarity and completeness.

(b) The transmission charges should be shared among users of ISTS in accordance with CERC (Sharing of Inter-state transmission charges and losses) Regulations, 2010.

(c) The methodology of sharing of transmission charges should be as under:

(i) Prior to beginning of a quarter for which POC charges are to be specified, Designated ISTS Customers (DICs) need to provide their peak demand/injection from their generating stations. This data is fed into POC software which has the entire grid modelled. Injection into / drawal from ISTS in respect of each DIC is automatically derived from the peak demand/injection data provided by DICs.

(ii) Based on projected peak injection/drawal requirement, transmission charges are allocated to various nodes under POC mechanism. These charges should be divided by GNA (MW) of each DIC to determine POC rate for each DIC. These rates should be put into slabs as per prevailing Sharing Regulations notified by CERC.

(iii) There may be cases where projected peak injection /drawal in actual time frame i.e. just prior to beginning of a quarter will be different from the GNA quantum projected 5 years before by a DIC. In such cases projected ISTS drawal/injection as projected before beginning of quarter should be used in the POC software for the purpose of allocation of transmission charges as in the prevailing CERC Sharing Regulations. However, additional charges should be levied for injection /drawal beyond GNA sought by an entity so as to bring seriousness while seeking GNA. An example is illustrated below for clarity:

Suppose an entity has sought GNA for 5,000 MW for Quarter 2 of year 2021-22. In May 2021, entity would be required to provide its projected demand/ injection for determination of transmission charges for quarter July-September 2021. Suppose this entity has 3000 MW under Long term PPA and 1000 MW under Medium term PPA. In July 2021 it does Short term PPA for another 2,500 MW, thereby its total transaction shall be equal to 6500 MW which is 500 MW more than 120% of its GNA, it should be liable to pay transmission charges @ 1.25 times POC rate for this 500 MW and normal POC rate for drawl up to 6000 MW.

(iv) In cases where power is tied up under contracts other than short term contracts, the POC charges should continue to be calculated directly at drawal nodes as in the prevailing Sharing Regulations.

(v) The DISCOMs seem to have an apprehension that they may be required to pay transmission charges for the entire quantum of GNA which would be projected 4 years before and may cause huge penalty in case of wrong projection. The apprehension is misplaced as the basic premise of Sharing Regulations is that the transmission charges are usage based. Hence a DIC will be allocated transmission charges which are commensurate to its usage of ISTS as per its projected demand for the next quarter. However DISCOMs should endeavour to seek GNA as prudently as possible and there should be additional transmission charges if actual drawal is more than 120% of its GNA. GNA quantum should be used to determine the slab rate for POC Charges and additional transmission charges should be payable by a DIC only in case the drawal from ISTS is beyond 120% of Withdrawal GNA.

(vi) An entity transacting power in a grid is either an injecting DIC or a withdrawal DIC. As per the proposed mechanism for sharing of transmission charges, each entity should be paying as per its GNA quantum under first bill as per sharing mechanism currently in vogue for long term access. Since it should be seeking GNA quantum for its maximum injectable/maximum drawal quantum required, it should transact under power exchange within this quantum for which it should pay charges under first bill. Hence there should be no separate transmission charges for exchange transactions / short term transactions."

2.2.2 Hence, the sharing of transmission charges under GNA mechanism shall be done amongst the users of ISTS in accordance with the proposal of the Committee. Further, required amendment shall be done in due time in the Sharing Regulations to incorporate the provisions of the regulations on GNA."

4.20.2 **Analysis and recommendations of the taskforce:** The taskforce observes that the final regulations is yet to be notified. If the recommendations has to be based on draft Regulations, the modified PoC or Uniform charges method as proposed may be used under GNA. The sharing of HVDC as based on LTA+MTOA shall be replaced by GNA under GNA regime.

4.21 TOR 7: Final Recommendations on Transmission pricing;

4.21.1 Based on discussions under TOR 5 and TOR 6, final recommendations are included in this Clause.

4.21.2 Two options for transmission pricing are proposed:

(a) **Point of Connection charge based**

This methodology shall have four components of transmission charge viz (a) Point of Connection charge (b) Reliability charge (c) Residual Charge (d) HVDC charge.

(a)Point of Connection Charge- The base case shall be prepared as per last month's actual All India peak for billing in subsequent month. Percentage utilisation for each line may be determined and discounted MTC for such line should be considered in the base case as per its utilisation. To determine this component, the flow in the line in the base case as prepared above should be captured and should be divided by loadability of the line. The loadability of the line shall be considered as per CTU website considered for ATC/TTC. Based on MTC and base case flow, PoC charges shall be calculated for each entity as per existing hybrid method. This will provide Charges in Rs. Crore for each zone. These charges should be divided by actual ISTS drawal /injection considered in the base case. There is no requirement of slabbing the rates. For billing these rates should be multiplied by blockwise actual ISTS drawal /injection for each entity.

(b) Reliability Charge- The base case shall be prepared as per last month's actual All India peak. Contingency of n-1 should be simulated for all lines one by one. The flows in all lines in this contingency should be captured. Such contingencies should be created for all the lines and flows be captured. Reliability component for each line shall be taken as (Maximum flow in the line among all contingencies – Base case flow). Percentage of transmission charges corresponding to reliability component shall be reliability charge for each line. Reliability charge for all lines to be added to get All India Reliability Charges. Reliability charges are to be shared by all DICS in ratio of their peak ISTS drawal /injection for the month and for generators in ratio of their untied LTA.

(c) Residual Charge-After calculating the utilisation percentage and reliability percentage, there shall be a residual component left for each line. The total monthly transmission charge for each licensee should be recovered fully. Hence the residual component shall be shared among all entities in the ratio of their contracted capacities i.e LTA +MTOA and for generators in ratio of their untied LTAor GNA as the case may be.

(d) HVDC-All HVDC except back to back HVDC and that of National importance shall be shared by entities for whom it has been created i.e it shall be shared on causer pays principle as per present mechanism in vogue. In modified PoC method, reliability component of these HVDCs as average reliability percentage calculated for AC system shall be considered and billed under reliability charge.

(e) Merchant generators shall be treated as being done currently.The methodology for other generators with untied LTA shall also as being done under prevailing mechanism. i.e generation corresponding to untied LTA shall be allocated charges. Such generation will based on generation at time of All india peak for the month for PoC component and based on peak generation corresponding to untied LTA for reliability component.

(f) Implication of waiver for Renewable – **A**ugmentation done for renewable projects (systems specifically created considering renewable generation) should be separately listed. The MTC for such system should be allocated to all entities in the ratio of their contracted capacity.

(b) **Uniform charges method**

(a) All India Monthly transmission charges (excluding evacuation HVDCs) shall be divided by Average ISTS drawal / ISTS injection for all entities. All entities implies entities to whom transmission charges are to be billed. This will not include generators whose full /part capacity is tied up under long term PPA. For generators this quantum will be considered as contracted LTA capacity which is not tied up under PPA. The Average ISTS drawal/injection shall be determined by taking average of 15 minute blockwise data for the month for each entity. For states which inject in ISTS in while calculating the average their injection will be considered as drawal and average MW will be arrived at.

(b) For billing, the uniform rate (Rs./MW/block) shall be multiplied by actual ISTS drawal/injection for states. For generator, the billing shall be based on Uniform rate X contracted capacity not tied up.

(c) Augmentation done for renewable projects (systems specifically created considering renewable generation) should be separately listed. The MTC for such system should be allocated to all entities in the ratio of their contracted capacity.

(d) The treatment of HVDC (except back to back) shall be as per current methodology of "causer pays" principle. No reliability component shall be deducted from such HVDCs as done currently.

(c) In the proposed methodologies, distance, direction and quantum sensitivity shall be as under

- Modified PoC- PoC component shall be distance, direction and quantum sensitive. Reliability and Residual component shall be quantum sensitive only.
- Uniform methodology- The charges shall be quantum sensitive and not distance and direction sensitive.

(d) However Member representing POSOCO had different views on some of the above recommendations. His views are given below:

(i) Charges of HVDC links, which are useful for controlled power flow in a large synchronous grid should be shared by all DICs in ratio of LTA/MTOA.

(ii) The charges should be determined based on data of previous quarter ex-ante. An entity's PoC rate should be multiplied by its maximum injection/drawal during previous quarter. Block-wise MW effectively means energy. Any transmission charge sharing methodology based on energy will distort merit order. Further, it is not desirable for a sunk investment like transmission. Sharing may be based on GNA/LTA-MTOA/peak drawal.

(iii) Slabbing should continue. If slabs are removed, it would be against the provision of Tariff Policy.

(iv) Uniform Charges method: The Monthly transmission charge shall be divided by sum of maximum ISTS drawal/injection or LTA/MTOA, whichever is higher for the quarter. This rate shall be multiplied by maximum ISTS drawal / injection or LTA/MTOA, whichever is higher for billing purpose.

(v) Till implementation of GNA, STOA rates can be declared on annual basis

(vi) Charges should be paid by both load and generator. Under GNA mechanism, both generators and loads should pay. Generator may further recover from drawee entities based on contract.

TOR 8: To assess the utilization of transmission system and suggest measures to improve the utilization of transmission system;

4.22 Utilization of transmission system

4.22.1 Representative of Powergrid has submitted as follows on the aspect of utilisation of transmission system:

"

A. Background

Utilization of any asset is the extent up to which intended objectives for which the asset is planned is effectively and efficiently achieved. For a Transmission asset, these intended objectives are the criteria considered for Transmission Planning.

Since the inception of power sector in India, transmission planning follows generation. Before the formation of POWERGRID, ISTS systems were planned to evacuate power from ISGS to the identified beneficiaries. After the formation of POWERGRID also, most of the transmission planning is based on requirement of generation capacity addition as indicated by generation companies. In addition, transmission links have been planned to transfer power from surplus regions to deficit regions, to cater increase in demand and for system strengthening to achieve reliability. Recently to evacuate power from renewable rich regions, Green energy corridors have been planned.

B. Factors affecting Transmission Planning:

Planning of transmission system in a meshed power system is carried out based on many factors. All these factors affect the power flow through the transmission lines. The major factors are summarized below:

1. **Grid Security and Reliability (N-1/N-1-1):**The transmission lines in a meshed network is planned with inherent capacity margin to take care of N-1/N-1-1 contingencies as per Transmission Planning Criteria 2013 of CEA.

   This may be explained with a simple interconnection of one line between a generator and a load centre. If the line will have 100% utilization in terms of capacity and actual power flow, there would be no redundancy for outage/contingency condition. In order to maintain N-1 contingency, two lines would be required in this case with 50% utilization of each line.

Similarly, to maintain N-1-1 condition, three lines would be required and the utilization of each line will be brought down to 33%.

2. **Grid Stability**: The transmission system is also required to transfer power without loss of stability. For example, in case of long transmission lines, additional parallel corridors are provided to maintain stable operation of the grid which may lead to low power flow.

3. **Load - Generation condition**: Transmission lines facilitate flow of power from generations (source) to load centres (sink). The quantum of power therefore, largely depends upon the availability of generation/load at either end. The daily variation of load from Peak to Off-peak is generally in the range of 30-40%. The seasonal variation of hydro generation between monsoon & winter is almost 80-90%. Further, the renewable generation also varies a lot throughout the day. All these factors result in variation in the power flow in the transmission lines.

4. **Peak power flow requirement**: Transmission lines are mainly planned to cater the anticipated peak power requirement in ideal conditions, in order to avoid any generation rescheduling or load shedding.

5. **Long term perspective/Right of Way optimization**: While planning Transmission lines optimal utilization of Right of way, future load forecasting/ Generation potential etc. are also taken care. Accordingly, high

capacity transmission lines are built, which may lead to lower utilization in the initial stage.

6. **Transmission interconnecting two areas/regions**: Transmission lines interconnecting two different areas/regions are planned to facilitate transfer of power from surplus to deficit areas/regions depending upon the requirement. In this case, the utilization may be low; however, the same is required for operation of the whole grid and mutual exchange of power.

7. **Voltage level limitation in Transmission:** Limited kV rating choices e.g. 132 kV, 220 kV, 400 kV and 765 kV for HVAC are available in Transmission. This technical constraint in voltage levels limits the choices available for Transmission planning. Further per-unit cost of transmission tends to reduce with increase in the kV level of transmission lines. Thus to meet present and future demand which increase in phases, transmission elements are planned with the next higher available kV rating for the specific need leading to low utilization in the initial years.

8. **Renewable Integration into the Grid:**
Most of the wind and solar generations are located in various pockets. Since these generations are located far off from the load centres and also to meet the balancing requirement, transmission corridors are required from the RE rich complexes. However, Utilization of these corridors shall be affected by intermittency and variability of generation.

Thus, by the inherent nature of ISTS planning, transmission systems always have spare and redundant capacity. In view of the discussion above, Utilization of transmission asset or network can only be analyzed holistically based on the all discussed parameters which are in line with prevailing planning philosophy encompassing present & projected demand, RoW limitations, Techno-Financial Constraints , adequacy, security & reliability of the Grid etc.

C. Provisions in Policy:

i. Section 7 of Tariff Policy,2016 states as following

Quote:

....The tariff policy, in so far as transmission is concerned, seeks to achieve the following objectives:

"Ensuring optimal development of the transmission network ahead of generation with adequate margin for reliability and to promote efficient utilization of generation and transmission assets in the country;"......

Unquote:

ii. Following provisions of National Electricity Plan,2012 states that

Quote:

Section 3.3 Transmission Planning Criteria
".....All these factors have made transmission planning a challenging task. Adequate flexibility is required to be built in the transmission system plan to cater to such uncertainties, to the extent possible. However, given the uncertainties, the possibility of stranded assets or congestion cannot be entirely ruled out."

Unquote:

iii. Following provisions of National Electricity Policy,2005 states that

Quote:

Section 5.3 Transmission
"5.3.5 To facilitate orderly growth and development of the power sector and also for secure and reliable operation of the grid, adequate margins in transmission system should be created. The transmission capacity would be planned and built to cater to both the redundancy levels and margins keeping in view international standards and practices......."
Unquote:

D. Utilization of Transmission Assets: The flow of power transfer through the transmission element and its utilization varies in real time operation depending on the following factors also;

i. **Dependency on Inter connected Transmission Systems:** Inter State transmission is not an independent system but part of an interlinked power system. Transmission system provides service of inter-connection between the source (generator) and consumption (load centres) of electricity. The transmission systems in the country consist of Inter-State Transmission System (ISTS) and Intra State Transmission System (Intra-STS). The ISTS is the top layer of national grid below which lies the Intra-STS. Optimum development of transmission system requires commensurate development of the inter State & intra-State transmission systems. The utilization of ISTS network gets adversely affected on account of non optimal development of any of the link in Power Sector chain i.e Generation, Demand and Intra State Transmission network.

ii. **Demand pattern and Operational restrictions by Grid operator**: The power flow in a particular transmission system depends upon a number of variables and grid conditions including seasonal variation, peak/off-peak load, scheduling of generation as per merit order dispatch, availability of renewable generation, and outage of lines due to over voltage etc., which are beyond the control of the Transmission Licensee. The power flow or utilization of the asset varies at any given point of time is completely dependent on the grid operation controlled by the Grid Operator.

The daily variation of load from Peak to Off-peak is generally in the range of 30-40%. The seasonal variation of Hydro generation between monsoon & winter is almost 80-90%. Further, the renewable generation also varies a lot throughout the day.

E. Assessment and improvement of utilization

In a meshed network, whole grid works as one single unit where individuality of a transmission element is lost in it. Because electricity flows along paths of least resistance, the direction and quantity of power flowing across any network element is decided by the equivalent resistance offered by alternative paths in the network. Therefore, utilization of individual transmission line of system is not prudent and considering operational criteria, it is extremely difficult to quantify utilization of individual assets independently.

In June 2015, Sub-Committee on Congestion in Transmission in its report has noted that even in advanced Countries Transfer Capability is of the order of 21% of transmission capacity

Keeping above in view, it is stated that utilization of a transmission system has to be looked from its effectiveness in delivering its intended benefits and output it delivers to complete Indian Power system such as enabling evacuation of Generation in the grid, Reduction in power procurement costs, Reduction in congestion, Enabler of Power, provide reliability operation of grid, ensuring maximum availability of all transmission system, Renewable integration etc.

4.30.2 Few stakeholders have suggested that an independent agency / Existing agency shouldmonitor the performance/ degree of utilisation of the transmission system vis a vis its technical and declared capacity.

4.22.2 **Analysis and Recommendations of the taskforce with respect to Utilisation**

The taskforce observes that utilisation of line varies over a day and from season to season (refer graphs of flows in the sample lines attached in the report). The flow in the linesdepends on load, generation scenario and availability of upstream / downstream system i.e availability of integrated system. However keeping in view the stakeholders suggestions, taskforce suggests that utilisation of transmission system should be monitored at RPC level and reasons for cases of low utilisation should be ascertained and documented. The remedial measures to improve utilisation should also be discussed. RPCs should monitor the same quarterly and upload the status report on its website.

The RPC shall ensure that planning of new system is done after considering redundancy in existing system as brought out in above analysis keeping in view the reliability requirements.

TOR 9: To assess the reactive power requirement in integrated grid and examine the adequacy of available reactive power management resources;

4.23 Reactive Power requirement vs availability

4.23.1 The issue of reactive power management was discussed and inputs of CEA was sought regarding what is being done now, what are suggestions for future / upcoming requirements. Representative of CEA has submitted as follows:

"

(a) Voltage control in an electrical power system is important for proper operation of electrical power equipment to prevent overheating of generators and motors, to reduce transmission losses and to maintain the ability of the system to withstand and prevent voltage collapse. In general terms, decreasing reactive power causes voltage to fall while increasing it causes voltage to rise. Voltage collapse occurs when an increase in load or less generation or transmission facilities causes dropping voltage, which causes a further reduction in reactive power from capacitor and line charging and thus further voltage reductions. If voltage reduction continues, these will cause additional elements to trip, leading further reduction in voltage and loss of the load. The result in these entire progressive and uncontrollable declines in voltage is that the system is unable to provide the reactive power required for supplying the reactive power demands.

(b) Voltage control and reactive-power management are two aspects of a single activity that both supports reliability and facilitates commercial transactions across transmission networks. On an alternating-current (AC) power system, voltage is controlled by managing production and absorption of reactive power. There are three reasons why it is necessary to manage reactive power and control voltage.

(c) First, both customer and power-system equipment are designed to operate within a range of voltages, usually within ±5% of the nominal voltage. At low voltages, many types of equipment perform poorly; light bulbs provide less illumination, induction motors can overheat and be damaged, and some electronic equipment will not operate at all. High voltages can damage equipment and shorten their lifetimes.

(d) Second, reactive power consumes transmission and generation resources. To maximize the amount of real power that can be transferred across a transmission interface, reactive-power flows must be minimized. Similarly, reactive-power production can limit a generator's real-power capability.

(e) Third, moving reactive power on the transmission system incurs real-power losses. Both capacity and energy must be supplied to replace these losses.

(f) Voltage control is complicated by two additional factors

First, the transmission system itself is a nonlinear consumer of reactive power, depending on system loading. At very lightly loaded system generates reactive power that must be absorbed, while at heavy loading the system consumes a large amount of reactive power that must be replaced. The system's reactive-power requirements also depend on the generation and transmission configuration. Consequently, system reactive requirements vary in time as load and generation patterns change.

(g) The bulk-power system is composed of many pieces of equipment, any one of which can fail at any time. Therefore, the system is designed to withstand the loss of any single piece of equipment and to continue operating without impacting any customers. That is, the system is designed to withstand a single contingency. Taken together, these two factors result in a dynamic reactive-power requirement. The loss of a generator or a major transmission line can have the compounding effect of reducing the reactive supply and, at the same time, reconfiguring flows such that the system is consuming additional reactive power.

(h) At least a portion of the reactive supply must be capable of responding quickly to changing reactive-power demands and to maintain acceptable voltages throughout the system. Thus, just as an electrical system requires real-power reserves to respond to contingencies, so too it must maintain reactive-power reserves.

(i) Synchronous generators, SVC and various types of other DER (Distributed energy resource) equipment are used to maintain voltages throughout the transmission system. Injecting reactive power into the system raises voltages, and absorbing reactive power lowers voltages.

(j) Voltage-support requirements are a function of the locations and magnitudes of generator outputs and customer loads and of the configuration of the DER transmission system.

(k) What is being done now for reactive power management?

For reactive power management following measures are being taken:

i) Adequate reactive compensation based on system studies is being planned at new EHV sub-stations.

ii) Fixed line reactors are being converted into switchable line reactors as per requirement.

iii) Based on operational feedback form NLDC / SLDCs reactors are being planned to overcome the over voltage problems.

iv) Hydro generation developers with unit size of 50 MW and above are being requested to design the machine capable of operation in synchronous condenser mode.

v) 2 no. of SVC and 14 no. of STATCOMs has been planned since 2011 are under implementation / some commissioned to provide voltage support to grid during dynamic condition. The details are enclosed below:

Northern Region:

1. 30th SCM: (19.12.2011)
   SVC
   (i) Ludhiana S/s - (+) 600 MVAR / (-) 400 MVAR
   (ii) Kankroli S/s - (+) 400 MVAR / (-)300 MVAR

2. 32nd SCM: (31.08.2013)
   STATCOM

(i) Lucknow $\pm$ 300 MVAR
(ii) Nalagarh $\pm$ 200 MVAR

Western Region

1. 36 th SCM : (29.08.2013)
   STATCOM
   (i) Aurangabad $\pm$300 MVAR
   (ii) Gwalior $\pm$200 MVAR
   (iii) Satna $\pm$300 MVAR
   (iv) Solapur $\pm$300 MVAR

Eastern region

1. 15th SCM: (27.08.2013)
   STATCOM
   (i) Rourkela ± 300 MVAR
   (ii) Kishanganj ± 200 MVAR
   (iii) Ranchi(New) ± 300 MVAR
   (iv) Jeypore ± 200 MVAR

Southern region

1. 35th SCM : (04.01.2013)
   STATCOM
   (i) Hyderabad (PG) $\pm$ 200 MVAR
   (ii) Udumalpet $\pm$ 200 MVAR
   (iii) Trichy $\pm$ 200 MVAR

2. 38th SCM: (07.03.2015)
   STATCOM
   (i) N P Kunta ±100 MVAR

(l) What are suggestions for future / upcoming requirements?

i) Adequate reactive compensation based on system studies would be planned for new EHV sub-stations.

ii) Based on operational feedback form NLDC / SLDCs reactors would be planned to overcome the over voltage problems.

iii) Discoms should be advised to switch off capacitors installed at lower voltage level during light load conditions.

iv) Based on the operating experience of STACOMs, studies needs to be carried to identify the locations in the grid requiring voltage support during dynamic condition.

v) Transmission licensees / utilities should be advised to make on line tap changer on EHV ICTs functional.

"

4.23.2 Mr. S.K. Soonee stated that old load centre generators may be used as synchronous generators to provide reactive power. He also stated that RE generators should also be mandated to provide reactive capability.

4.23.3 **Analysis and Recommendationsof the taskforce with respect to reactive power**

(a) The taskforce has perused NLDC report on "Operational feedback on Transmisison Constraints forJanuary 2019 dated 25.1.2019. It is observed from the Report that there are many nodes which experience high voltage all the time and many lines are opened for high voltage. The data for All India and Northern region is attached below:

1.9.Action taken in real-time to mitigate constraint

Lines opened on High Voltage: -

A graphical representation of number of 765 kV lines opened on daily basis to control high voltage is given below in fig 12. (X axis: Date, Y axis: Number of lines opened). A list of lines generally opened to control high voltage is also enclosed.

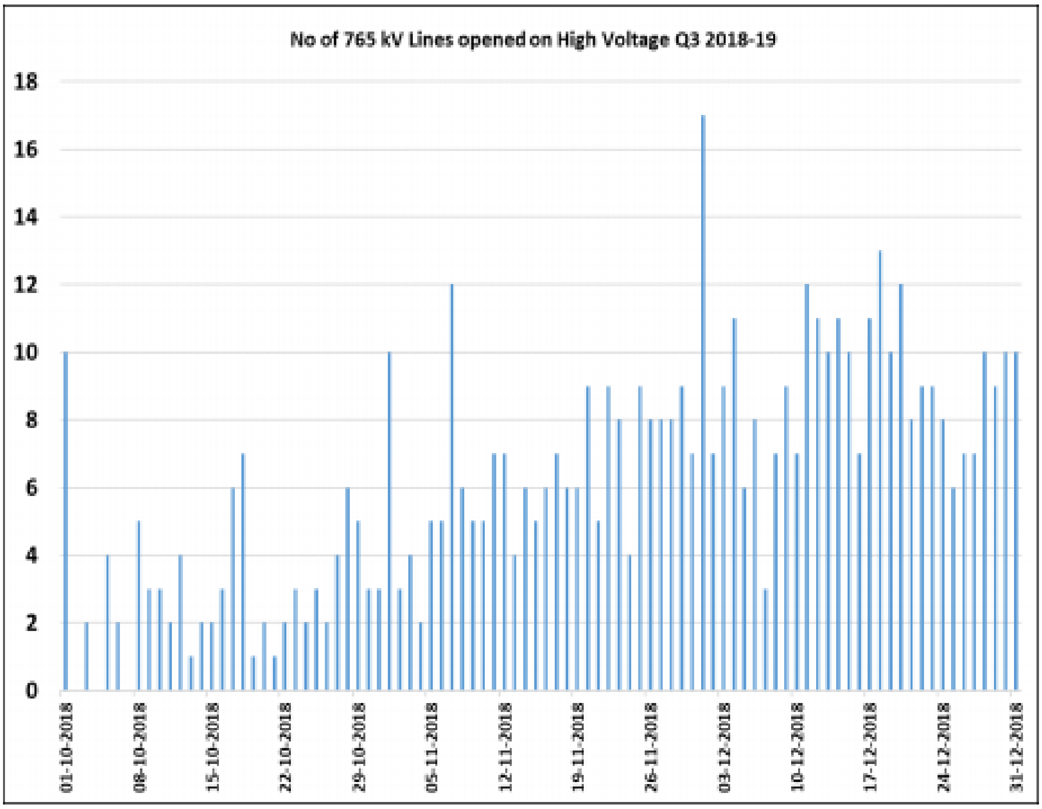


Figure 13: 765 kV lines opened on daily basis to control high voltage

Figure 23: Number of 765kV lines opened on high voltagein Q3-2018-19

Table 24: 765kV lines opened more than 5 times on high voltage in Q3-2018-19

Table 2: 765kV opened more than 5 times on High Voltage in last quarter:

S.No.	Transmission Element opened	Total No. of Outages
1)	765 kV Moga-Meerut	75
2)	765 kV Kurnool-NPS-1	44
3)	765 kV Kurnool-NPS-2	23
4)	765kV Dhule-Vadodara	36
5)	765kV New Parli- Solapur-I	31
6)	765kV New Parli- Solapur-II	29
7)	765kV Phagi-Bhiwani-I	32
8)	765kV Fatehpur-Agra-I	26
9)	765kV Nizamabad- Maheswaram-II	45
10)	765kV Nizamabad- Maheswaram-I	38
11)	765kV Fatehpur-Agra-II	19
12)	765kV Pune-Sholapur	19
13)	765kV Kanpur-Aligarh	11
14)	765kV Meerut-Bhiwani(PG)	13
15)	765kV Fatehabad-Lalitpur-II	12
16)	765kV Kadapa-Thiruvalam-I	55
17)	765kV Kurnool-Kadapa-I	27
18)	765kV Warora-New Parli-I	9
19)	765kV Warora-New Parli-II	11

S.No.	Transmission Element opened	Total No. of Outages
20)	765kV Durg-Wardha-II	8
21)	765kV Fatehabad-Lalitpur-I	7
22)	765kV Kurnool-Kadapa-II	38
23)	765kV Wardha-Aurangabad-IV	7
24)	765kV Wardha-Aurangabad-II	7
25)	765kV Aligarh-Jhatikara	7
26)	765kV Durg-Wardha-I	6
27)	765kV Durg-Wardha-III	7
28)	765kV Kurnool-Thiruvalem-II	26
29)	765kV Kurnool-Thiruvalem-I	14
30)	765kV Aligarh-Orai-1	6
31)	765kV Aurangabad-Phadge-I	6
32)	765 kV Kurnool-Raichur 2	11
33)	765kV Kadapa-Thiruvalam-II	36

From the operational point of view following instructions (as per NLDC operating procedure) were given to avoid over voltages in the system.

• The bus reactors are switched in.

• The manually switchable capacitor banks are taken out.

• The switchable line/tertiary reactor are taken in.

•Optimized the filter banks at HVDC terminal.

• All the generating units on bar are advised to absorb reactive power within the capability curve.

• Reduced power flow on HVDC terminals so that loading on parallel EHV network goes up resulting in drop in voltage.

•As specified in table above many lightly loaded lines were opened in consultation with RLDC/SLDC for ensuring security of the balanced network.

* In lightly loaded lines priority were given to those lines which have switchable line reactor, so that their line reactors(L/R) can be converted to bus reactors(B/R) to contain the overvoltage. The Stations need to have such convertible L/R to B/R

scheme to maintain system voltage within limits specified under Central Electricity Authority (Grid Standards) Regulations, 2010."

(b) The data for Northern region is as below:

<u>**Section 2: Action taken in real-time to mitigate constraint**</u>

2.2.1 Lines opened on High Voltage

X axis: Date, Y axis: Number of lines opened). A list of lines generally opened to control high voltage is also enclosed.

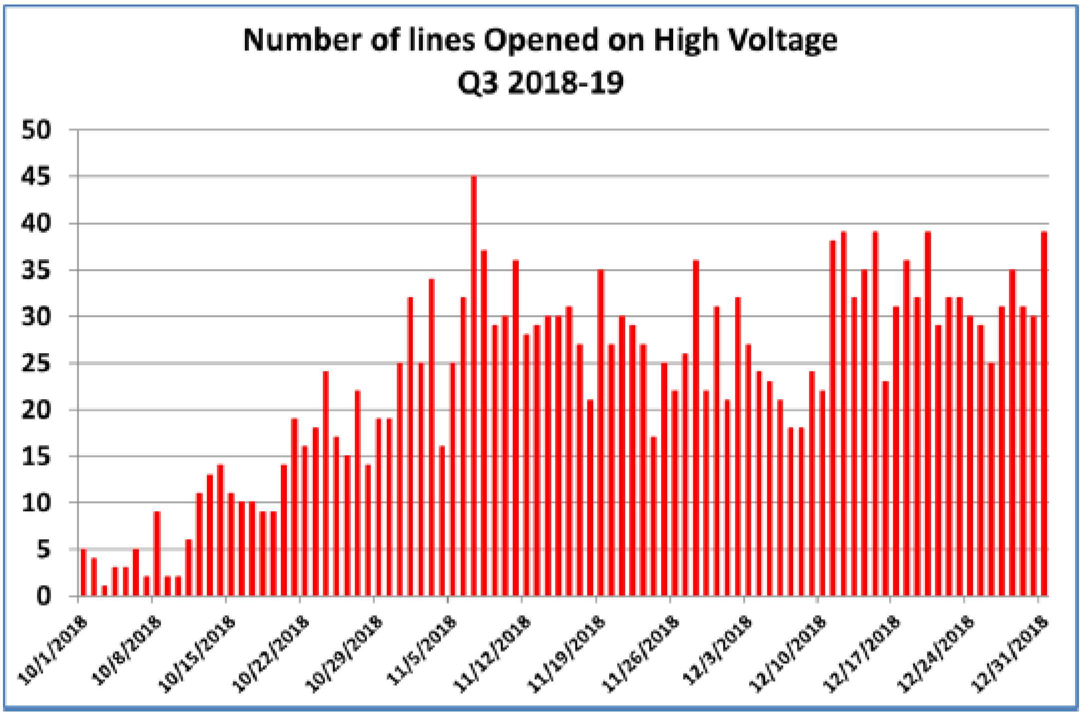


Fig. 1: Lines opened on High Voltage

Figure 24: Number of Lines opened on high voltagein Q3-2018-19

2.1.4 Nodes Experiencing High Voltage

S. No	Nodes	Season/ Antecedent Conditions	Figure/ table no.	Has the constraint occurred in earlier quarter?
1	Agra	All time	Fig. D1	Yes (Q3, Q4 2017-18)
2	Suratgarh	All time (Bus CVT error)	Fig. D2	Yes (Q3, Q4 2017-18)
3	Mahendragarh	All time	Fig. D3	Yes (Q3, Q4 2017-18)
4	Jhajjar	All time	Fig. D4	Yes (Q3, Q4 2017-18)
5	Rajpura	All time	Fig. D5	Yes (Q3, Q4 2017-18)
6	Makhu	All time	Fig. D6	Yes (Q3, Q4 2017-18)
7	Nakodar	All time	Fig. D7	Yes (Q3, Q4 2017-18)
8	Jind	All time	Fig. D8	Yes (Q3, Q4 2017-18)
9	Agra(UP)	All time	Fig. D9	Yes (Q3, Q4 2017-18)
10	Paricha	All time	Fig. D10	Yes (Q3, Q4 2017-18)
11	Harshvihar	All time	Fig. D11	Yes (Q3, Q4 2017-18)
12	Jalandhar	All time	Fig. D12	Yes (Q3, Q4 2017-18)
13	Rampur	All time	Fig. D13	Yes (Q3, Q4 2017-18)
14	Nallagarh	All time	Fig. D14	Yes (Q3, Q4 2017-18)
15	Muktsar	All time	Fig. D15	Yes (Q3, Q4 2017-18)
16	Jhajjar	Most Time	Fig. D16	Yes (Q3, Q4 2017-18)
17	Kabulpur	Most Time	Fig. D17	Yes (Q3, Q4 2017-18)
18	Koldam	Most Time	Fig. D18	Yes (Q3, Q4 2017-18)
19	Nuhiyawali	Most Time	Fig. D19	Yes (Q3, Q4 2017-18)
20	Fatehpur	Most Time	Fig. D20	Yes (Q3, Q4 2017-18)
21	Bhiwani(BBMB)	Most Time	Fig. D21	Yes (Q3, Q4 2017-18)
22	Bhiwani	Most Time	Fig. D22	Yes (Q3, Q4 2017-18)
23	Dhuri	Most Time	Fig. D23	Yes (Q3, Q4 2017-18)
24	Bawana	Most Time	Fig. D24	Yes (Q3, Q4 2017-18)
25	Malerkotla	Most Time	Fig. D25	Yes (Q3, Q4 2017-18)
26	Abdullapur	Most Time	Fig. D26	Yes (Q3, Q4 2017-18)
27	Sonepat	Most Time	Fig. D27	Yes (Q3, Q4 2017-18)
28	Fatehabad	Most Time	Fig. D28	Yes (Q3, Q4 2017-18)
29	Karcham Wangtoo	Most Time	Fig. D29	Yes (Q3, Q4 2017-18)
30	Parbati 3	Most Time	Fig. D30	Yes (Q3, Q4 2017-18)
31	Maharanibagh	Most Time	Fig. D31	Yes (Q3, Q4 2017-18)
32	Dhuri	Most Time	Fig. D32	Yes (Q3, Q4 2017-18)
33	Sikar	Most Time	Fig. D33	Yes (Q3, Q4 2017-18)
34	Neemrana	Most Time	Fig. D34	Yes (Q3, Q4 2017-18)
35	Amritsar	Most Time	Fig. D35	Yes (Q3, Q4 2017-18)
36	Dehar(BBMB)	Most Time	Fig. D36	Yes (Q3, Q4 2017-18)
37	Nathpa Jhakri	Most Time	Fig. D37	Yes (Q3, Q4 2017-18)
38	Panchkula	Most Time	Fig. D38	Yes (Q3, Q4 2017-18)
39	Bhiwadi	Most Time	Fig. D39	Yes (Q3, Q4 2017-18)
40	Talwandi Saboo	Most Time	Fig. D40	Yes (Q3, Q4 2017-18)
41	Allahabad	Most Time	Fig. D41	Yes (Q3, Q4 2017-18)
42	Parbati Pool	Most Time	Fig. D42	Yes (Q3, Q4 2017-18)
43	Jodhpur	October	Fig. D43	Yes (Q3, Q4 2017-18)
44	Jhatikara	Sometimes	Fig. D44	Yes (Q3, Q4 2017-18)
45	Shree Cement	Sometimes	Fig. D45	Yes (Q3, Q4 2017-18)
46	Chameral	Sometimes	Fig. D46	Yes (Q3, Q4 2017-18)
47	Mandola	Sometimes	Fig. D47	Yes (Q3, Q4 2017-18)
48	Meerut	Sometimes	Fig. D48	Yes (Q3, Q4 2017-18)
49	Bhiwani	Sometimes	Fig. D49	Yes (Q3, Q4 2017-18)
50	Jhatikara	Sometimes	Fig. D50	Yes (Q3, Q4 2017-18)

**In above where high voltage is experienced for sufficient time all time has been used. For high voltages in particular month, month is specified. Sometimes means high voltages were for short duration throughout the quarter.*

From above data, it is clear that even during high demand season, high voltages are being observed at many of the stations in Northern region. It is expected that during coming winter months these high voltages in the grid would rise further.

"

(b) Similar is the case with other regions.

(c) TEPCO Powergrid, Japan did a study on "Reactive Power Management Project in India" under India-Japan Energy dialogue and submitted its findings and conclusions in January 2019. It had specifically studied Punjab system and has observed as follows:

"400kV voltage tends to rise due to charging current in long distance transmission line in off-peak period. Shunt reactor (ShR) is mainly installed for countermeasure. Operators switch off the transmission line with high capacitance for reducing voltage whenever needed.

-66kV or less voltage tends to drop due to reactive power consumption of load in peak period. Shunt capacitor (SC) is mainly installed for countermeasure. Under Voltage Load Shedding (UVLS) scheme is rarely operated to maintain voltage.

-On load tap changer is installed to transformer normally, however it is rarely used.

-Operators switch on/off SC and ShR manually to maintain the voltage within the upper and lower limits of Grid Code."

(d) It has suggested to use of On load tap changer through local or centralised VQC which may improve the reliability as follows:

- Improvement of system reliability

To maintain system voltage within grid code, operators switch off a lot of 400kV and 765kV transmission lines and system reliability gets worse. Following result is the comparison of using OLTC for voltage control.

	(Case1) Number of switching off TLs without OLTC control [cct]	(Case 2) Number of switching off TLs with OLTC control [cct]	Difference of switching off TLs [cct]	Difference of TL charging [Mvar]
765kV transmission line	2	1	1	688 (-408)* 280
400kV transmission line	27	16	11	600
Total	29	17	12	1288 (-408)* 880

*: ShR for compensation of line charging

Using OLTC is effective to improve system reliability

(e) The taskforce observes that there is a need to conduct studies to assess reactive power requirement considering peak and off peak scenarios since the reactive power sources currently in the grid are not adequate looking at requirement of opening of lines. The same should duly take into account the future load growth and addition of renewables. The usage of solar inverter for providing reactive compensation should also be studied. The possibility of studies being done through agencies which are already involved in such studies like METI (TEPCO, Powergrid), USAID or GIZ or inhouse may be explored.

TOR 10: To assess the available transfer capability and the measures to improve the same;

4.24 Assess the available transfer capability and the measures to improve the same;

4.24.1 The taskforce observed that Ministry of Power, Govt. of India had already constituted a "Taskforce on Power System Analysis under Contingencies and the Consultant M/s Powertech Labs was given the task of Examination and recommendation of methodology for optimum calculation of transfer capability (TTC/ATC) in planning and operation horizons

4.24.2 Sh. Pradeep Jindal, CEA was invited during 2nd meeting to give a presentation on outcomes of consultant report. He stated that Ministry of Power, Govt. of India constituted "Taskforce on Power System Analysis under Contingencies" as follow-up of recommendations of Enquiry Committee on Grid Disturbances of 2012 in Indian Grid. He further stated that Taskforce broadly made recommendations regarding Analysis of network behaviour under normal & contingency scenarios, Review of philosophy of operation of protection relays, Review of islanding schemes & Technological options to improve performance of the grid. In line with recommendations of Task Force, Ministry of Power directed to appoint consultants to conduct study/analysis to ensure secure & reliable operation of National Grid. The Consultant M/s Powertech Labs was given Six Tasks under "Review of Transmission System Transfer Capability and Review of Operational & Long Term Planning". He further stated that the consultant M/s Powertech Labs has submitted a report on Task –I and Task- II on 13th Jan 2017 and 7th April 2017.

Task –I:

A. Broad Scope:

1) Examination and recommendation of methodology for optimum calculation of transfer capability (TTC/ATC) in planning and operation horizons
2) Presentation to CEA, POSOCO, CTU and NRCE and Training in each RPC

B. Main Findings& Recommendations:

- Suggested two terms for transfer capability :
    - **System Operating Limit (SOL):By CTU** for Planning under intact system configuration and may revise SOL at least twice a year based on progress in construction of planned facilities. CTU may choose not to calculate TTC/TRM/ATC as these are originally commercial terms for trading.
    - **Total Transfer Capability (TTC): By POSOCO** for Operation and Scheduling under specified system operating conditions (voltage / stability limits can vary significantly). TTC is a commercial term and is commonly used in Power Market in US. In India, TTC is a reliability based limit.
- Area Interchange, Rated System Path & Flow Gate are three methodologies used for SOL/TTC calculation. In India, a combination of Rated System Path & Area Interchange methodology is used which appears to be the most suitable.
- Guidelines, criteria, necessary regulations to be developed to mandate CTU to calculate SOL for long term case at end of year when RPCs & CEA confirm & approve new lines/substations/facilities.
- No private entity to be allowed to participate in SOL/ TTC calculation as is the practice followed world-wide. POSOCO and CTU to declare all assumptions. POSOCO may also prepare a TRM Implementation Document (TRMID).
- In North America TSPs/TOPs follow NERC standards to transmit TTC/ATC values to neighboring TSPs/TOPs and market operators in a specific confidential format. SOLs of various paths& TRMID may be made public.
- SOL/TTC is calculated considering voltage and transient stability criteria which largely depend upon sufficiency of power flow and dynamic data
- A standard validated database to be established through an institutional arrangement. In North America, in-service equipment is supported by test data while long-term planned equipment only has generic dynamic data.
- Data owners like transmission owner, generation owner& load serving entities to be responsible for accuracy & updation of their data. This data may be verified by Transmission Planners & Operators.

- Considering deficiencies in models/availability of data, especially STU & generator data, thermal criteria may continue to be used until grid models are enhanced by CEA, CTU, POSOCO and STUs jointly. Then, gradual shift to considering voltage & transient stability criteria also is suggested.
- Govt. of India (MoP) should undertake Trainings, Workshops, Conferences and setup Technical committees & Working groups.

Task –II:

A. **Broad Scope:**
    1. Calculation of Transfer Capability in planning & operational horizon.
    2. Presentation to CEA, POSOCO, CTU & NRCE and Training in each RPC

B. **Main Findings & Recommendations:**

- February 2016 peak & off-peak cases were provided by POSOCO, and March 2017 peak & off-peak cases by CTU.
- For SOL/TTC calculation, the focus is on voltage stability (collapse). 5% margin is considered at first voltage collapse point to arrive at TTC value.
- "Generation increase-generation decrease" source-sink philosophy is applied. Generation increase is implemented by scaling up. For generation decrease, the available merit order is applied and units taken out of service (to remove its reactive support). Scaling down of generation is not recommended.
- Results correspond to first divergence backed off by 5% voltage stability margin (Voltage Collapse Case):

Path	Feb16 Peak TTC (MW)(Voltage Collapse Limit)			NLDC TTC (MW)
	From WR	From ER	Total	Total
NR-Import	12403	4526	16929	9950
SR-Import	6200	2650	8850	6650

Path	Mar17 Peak TTC (MW) (Voltage Collapse Limit)			CTU TTC (MW)
	From WR	From ER	Total	Total
NR-Import	16386	10604	26990	17100
SR-Import	7504	4851	12355	7275

- Considering CTU/POSOCO criteria of limiting the TTC value equivalent to thermal violation, under outage of one circuit of D/c line, TTCs need to be reduced to following values

Path	Contingency/Overloaded Interface Circuit	Feb16 Peak Limit (MW)		
		From WR	From ER	Total
NR-Import	157007 AGRA-PG 765. 327003 GWALIOR 765. ½	7834	1863	9697
SR-Import	337004 SHOLAPUR 765. 437001 RAICHUR-PG 765. ½	3759	2650	6409

Path	Contingency/Overloaded Interface Circuit	Mar17 Peak Limit (MW)		
		From WR	From ER	Total
NR-Import	187706 AGRA-PG 765. 368007 GWALIOR 765. ½	11483	7267	18750
SR-Import	378040 SHOLAPUR 765. 528003 RAIC800 765. ½	4272	3989	8261

- Sh. Pradeep Jindal also stressed the need for data improvement. He stated that data of generator data modeling needs to be improved and once a generator is commissioned its data should be revalidated for accuracy. Once models are sufficiently improved, a gradual shift to voltage security analysis is recommended. Till then, POSOCO and CTU may continue with current method which is more oriented toward paths thermal limitations.
- Sh. Pradeep Jindal stated ATC calculated under planning horizon by CTU and operational horizon by POSOCO are different. He informed the Taskforce that under current methodology of ATC calculation, CTU balances by increasing generation (at source) and decreasing generation (at sink) and POSOCO balances by increasing generation (at source) and increasing demand(at sink). Consultant has suggested that increasing generation (at souce) and decreasing generation (at sink) is a better method subject to Generation reduction is done on merit order basis. The database files being used for ATC calculations in planning horizon and operation horizon are different. The Taskforce felt that there is a need to harmonise both the files in respect of formats.

4.24.3 **The Consultant also gave presentation to the Commission on 5.3.2018 where following was discussed:**

"

a. Dr. A.K.Moharana, PLI made a presentation on Task I of Package B (Copy at Annexure-II). The concepts and methodology of calculation of System Operating Limit (SOL), Total Transfer Capability (TTC), Available Transfer Capability (ATC) and Transmission Reliability Margin (TRM) etc. were explained. It was mentioned that the system operator is required to calculate TTC for system operation as well as for market operation. However, CTU may calculate only SOL for system reliability under Planning horizon. CTU may provide the same to the operator for reference as this is not required to be made public. It was also suggested that the methodology & assumptions for SOL/TTC/ATC/TRM calculation may be documented properly. Dr.Moharana also mentioned that base case of NLDC and CTU are different and hence it is difficult to compare both the cases. Uniformity in the preparation of simulation cases was recommended.

b. Joint Chief (Engg.), CERC enquired about the present methodology of TTC calculation followed by CTU and POSOCO. She specifically asked if it is by increasing the generation in one region and increasing the load in other region or by increasing the generation in one region and decreasing the generation in other region.

c. Representative of NLDC replied that they calculate TTC by increasing the generation in one region and increasing load in the other region whereas CTU calculates by increasing generation in the one region and decreasing generation in other region. M/s PLI stated that CTU & POSOCO used hybrid of Area Interchange & Rated System Path methodology which is suitable for Indian Grid. Further, M/s PLI recommended that the generation increase, generation decrease philosophy with merit order generation dispatch may be considered by both CTU & POSOCO. Considering that the bus numberings, Area/Zones etc. are different in the base cases of NLDC and CTU, M/s PLI recommended that a common database be developed.

d. Joint Chief (Engg) asked the criteria followed by NLDC to decide on which generators to increase generation in exporting region. NLDC replied that they are aware of pockets based on historical trends where to increase the generation and accordingly they increase it. The variable cost of stations is currently not taken into account while increasing the generation or decreasing the generation by NLDC or CTU.

e. Shri Bakshi asked if there is any regulatory guideline internationally for the methodology to be followed. Dr.Moharana replied that NERC has broad guidelines. He replied that for different countries mainly three methodologies are followed, viz. Area Interchange, Rated System Path & Flow gate methodology. However, whichever methodology is adopted, the same including all assumptions & procedures need to be documented.

Dr.Moharana recommended reducing generation in the drawee region and increasing generation in the source region since load increase beyond a certain limit would be fictitious. Further while decreasing generation, instead of scaling down generation, switching off of generation units (using merit order) was recommended to remove the reactive support of the generating units which would practically not be available to support the grid. He stated that generation increase and generation decrease should be based on merit order since any scaling in generation decrease is a huge approximation. However, for increasing generation, scaling may be used.

f. Shri. A.K.Singhal, Member, CERC asked PLI representative whether the system / methodology being used by POSOCO and the one that has been proposed by PLI, will ultimately increase the ATC. Dr. Moharana replied that this cannot be said as the TTC may increase/reduce, if the correct dynamic data models are used in place of typical models being used due to unavailability of actual data models. He suggested that the load flow and dynamic data needs to be provided by the data owners. The generator data may be verified every five years.

g. Dr. Saeed Arabi, Powertech, made a presentation on Task II of Package B, which covers calculation of transfer capability for the entire country. He explained in detail the specific objectives of this task that was to calculate transfer capabilities, to estimate required transfer capabilities and to provide suggestions for addressing the gap.

h. Joint Chief (Engg.), CERC asked whether over load limit is dependent on the thermal limit of the line or the voltage collapse limit. She also observed that ATC at Voltage collapse limit was higher than thermal limit. She asked M/s PLI as to how can any limit be more than the thermal limit of the line. M/s PLI replied that the line should be loaded below thermal limit or voltage collapse limit whichever is lower. In case thermal limit is lower, voltage collapse limit should be monitored to ensure that loading (even if below thermal limit) should not be reaching near voltage collapse limit. He said a margin of 5% should be kept before voltage collapse limit.

i. M/s PLI emphasized the need of accurate modelling of the Indian Power System for effective computation of Total Transfer Capability (TTC). They informed that typical data which has been taken in modelling by CTU/POSOCO would give results that cannot be totally relied upon for actual system operation. And, therefore, accurate database is necessary for evaluation of these limits. Further, the data collection and validation is an extensive task and it took more than 10 years in case of North America. Further, the database updation is a continuous process. In North America, data is modeled and validated for every generator of capacity >20MVA. The data (including dynamic models for generators, exciter system, Governor, Power System Stabilisers, i.e. PSS, HVDC & FACTS devices etc.) is to be submitted by the equipment owners, reviewed, and models validated every 5 years which requires continuous & consistent effort. The submission of models in specified formats needs to be made mandatory as per Regulations. Once the models are sufficiently improved, shift to full voltage security analysis i.e. overload, voltage magnitude and voltage collapse is recommended. Further, the PSS tuning has a major impact on the damping of inter area modes and M/s PLI recommended that the tuning may be carried out every five years. M/s PLI observed that international practices is to generally keep at 5% to 10% for primary response, while in India, spinning reserve is around 5%. They also emphasized the need of implementation of Automatic Generation Control (AGC) for the entire Indian Grid. M/s PLI also suggested that the trip setting of the generators (UFGT) must be set below UFLS, else the system would be insecure and cascading/blackouts may result.

j. CE, NPC emphasized need of participation of generators in providing reactive support, governor response, secondary reserves, power system stabilizer etc. to support the grid.

k. Joint Chief (Engg.) enquired whether there was any chance that flows in the line are more than the ATC in real time to which Powertech representative replied that it can happen. She asked about the point/time, when operator should take action to control the flow. M/s PLI representative stated that there are three conditions- continuous overload, short term overload and emergency overload. In case of emergency overload, action is required in seconds. In case of short term overload, operators have 1 hour to take action. Operators should take action within 30 minutes in case of pre-contingency and immediately in case of post contingency. For 30 minutes, TRM should be used to manage."

4.24.4 Sh. Dilip Rozekar stated that in New Zealand, generator has to provide accredited data every 5 years. He also stated that in our Country, the generator doesnot provide requisite data of machine details required for modelling. He also emphasised the need of having tested data rather than generic data for generators.

4.24.5 SRPC gave feedback on TTC/ATC to NPC vide letter dated 10.7.2018 whereby following salient points were provided:

(i) The selection of control areas or group of control areas should be decided based on the direction of power flow and constraint in N-l contingency.

(ii) The corridor for TTC should be declared based on function of Constraints only.In the case represented if the constraint is in Tamil Nadu then control area for TTC declaration should be (Kerala + Tamil Nadu).In case constraint is in Kerala then it should be TTC should be declared for Kerala.In the same case if constraint is seen in Maharashtra then Group of Control Area should be Maharashtra + SR rather than only SR.

(iii) Methodology for TRM Computation.

- As per existing methodology of TRM computation two methods are in place (1) Two percent (2%) of the total anticipated peak demand met in MW of the control area/group of control area/region (to account for forecasting uncertainties) (2) Size of largest generating unit in the control area/ group of control area/ region.
- TRM works out differently in both the case. It is not clear by which method TRM should be considered. The concept behind considering the largest unit size as TRM is also not clear. It was felt that TRM should be based on the uncertainty in modelled nodal value with actual nodal value in real time.
- TRM % should be assessed based on the statistical analysis considering the error observed in modelled value and actual value.
- For some control area TRM can be higher than other areas considering historical error percentage.

(iv) Methodology for modelling Base Case.

The base case modelling is done based on anticipated nodal load and generation considering the historical nodal demand & Generation. In certain case it may happen that Generators having no long term or medium term access have generation under short term with no constraints. Due to network topology change such generators may become constraint aggravating generators, If such generation is considered in base case then TTC would be much less than the TTC computed with zero generation form these generators. So if base case is created based only on historical generation then some generators gets undue advantage over other generators even if they have long term/ medium term.

(v) Consideration of 50 % Counter flow benefit on account of LTA/MTOA transactions in the reverse direction.

Margin for STOA is =ATC-(LTA+MTOA). For computation if Margin by POSOCO the following equation is used:

ATC-{(LTA+MTOA from Exporting Region to importing region)-(0.5*(LTA+MTOA from Importing Region to exporting region))

The philosophy of considering of only 50% LTA/MTOA from importing region to exporting region for releasing margin to STOA is not comprehended.

(vi) Calculation of Margins from ATC.

The procedure for Margin computation for PX is not clearly defined. Under various scenario different methodology is adopted for reiease of margin for PX.

4.24.6 **Analysis and Recommendations of the taskforce with respect to ATC/TTC**

(a) Transmission transfer analysis investigates the ability of the electric power system to move power from one region to another. Capability of transmission system to support power transfers is a measure of interconnected transmission system reliability to assure that the interconnected network is operated in a secure and reliable manner.

(b) The assessment of ATC/TTC has already been carried out by Consultant appointed by MoP and salient findings have been provided by the Consultant. It is suggested that the recommendations of the Consulatnt should be carried out in a time bound manner.We agree with suggestions of Shri Dilip Rozekar regarding submission of accredited data by generators for modelling. The same is a part of recommendations of Consultant also and the same should be carried out in a time bound manner.

(c) We observe that consultant has provided major recommendations as (a) use of variable cost of generation i.e merit order while deciding which generation to increase or decrease.(b) Use of generation increase on sending side and generation decrease on recieveing side should be done in place of load increase done by POSOCO currently since increasing load beyond peak demand is fictitious (c)Use of accurate models (d) Check voltage collapse limits to ensure system doesnot operate near voltage collapse limits.

(d) We also observe that CTU uses TLTG software for ATC/TTC calculation. POSOCO has stated that it uses PSSE software and it increases generation / increase load manually based on identified pockets. In this regard the taskforce observes that since multiple generating points should be increased based on merit order and multiple load points are increased by POSOCO and the step has to be repeated iteratively till limits are hit, the same is manually impossible to be done. Further Consultant has also suggested has generation should be decreased in place of load increase. In case TLTG software is used to carry out ATC/TTC calculation, following are our analysis:

(e) The PSS/E software uses Transfer Limit Table Generation (TLTG) function which is based on linear powerflow model which is known as dc powerflow. The dc Powerflow converts the nonlinear ac problem into a simple, linear circuit analysis problem. The advantage of this approach is that efficient, non-iterative numerical techniques can be used to compute an approximate power flow solution. Many alternatives or contingencies can be investigated with the same computer effort that would be expended to calculate one ac power flow solution. The dc power flow ignores reactive power flow and changes in voltage magnitudes, and assumes that, for most circuits, Xij >> Rij and the angle between two buses is small. Therefore, there is some risk associated with steady state voltage violations; the dc powerflow method used to perform the contingency analysis assumes sufficient reactive power available to hold voltages constant. This analysis only confirms point-to-point transmission adequacy by identifying transmission limitations that arise as a result of the increased flows from one region to another region. In order to investigate the steady state voltage violations, a more detailed full ac powerflow studies must be done.

(f) A common approach used to find a limiting solution (using dc power flow) is to start with a base case and calculate the sensitivity of flow in monitored elements or groups of elements to a variation in interchange. This technique is often referred to as a distribution factor technique. When the sensitivity of elements is known, linear projection estimates permissible interchange.

(g) These days most utilities in North America use the full ac powerflow solution method to calculate the transfer limits using PV analysis feature. The program can run automatically a series of power flow solutions under normal and contingency conditions and determine the maximum transfer level that can be achieved before voltage collapse. In all activities using the dc solution technique, transfer limit ratings are calculated based only on MW flow, in contrast to the full ac solutions where transfer limit ratings are based on MVA flow.

Transfer Limit Calculation using PV Analysis:

The most direct and relevant measure of Voltage Stability (VS) margin is MW load, generation or transfer margin as shown by the Power-Voltage (PV) curves. PV curves directly reveal the margin to instability in terms of the relevant and measurable quantities (MW load, generation or transfer increase) for the system operators and planners. In addition, Modal Analysis at the nose of the PV curves can quickly identify the weak buses and the best places for the addition of reactive power sources.

The weak buses (for stability) are the ones that cause voltage instability at the nose of the PV curve because of the lack of reactive support. The weak buses for voltage stability are not necessarily the ones with the lowest voltage. In some cases, the weak region is confined to a small number of buses and when these buses become unstable, controlling this region (isolating it or shedding some of its load) will prevent voltage instability in the rest of the system. In other cases, a wide region in the system is affected and widespread control actions are needed to restore stability.

To compute the PV margins, the generation and/or load in some or all parts of the system are increased in discrete steps, or a power transfer from one part of the system to another is increased by varying the generation and/or load in the sending and receiving regions. At every step, after solving the pre-contingency power flows, contingencies are applied one by one and post-contingency power flows are solved. For each contingency, the highest load/transfer level that results in a stable post-contingency power flow solution is defined as the stability limit for that contingency. The distance between this limit and the initial load/transfer is the VS margin for that contingency, as shown in Figure. It should be clear that the stability margin is independent of which bus voltage is monitored and plotted in the PV curve because the load/transfer increase and the stability of post-contingency solution are not related to any particular bus voltage. The points on the curves of different buses will be different only in their Y (voltage) values, but their X values (and Pcm in Figure 1 will be the same. On the contrary, in QV curves, the injected reactive power, and its MVAr stability margin are strictly at the same bus whose voltage is monitored and plotted.

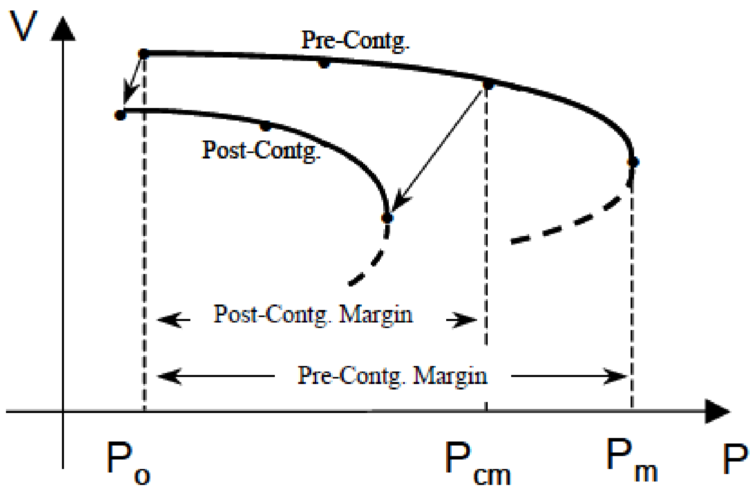


Figure: PV Curve and Stability Margin

Different PV analysis can be computed by choosing different patterns of load, generation or transfer scenarios. Each of these is a meaningful measure of stability, relevant for a particular situation, such as finding the limit of a particular transfer across the system or capacity of a specific part of the system for load/generation increase.

(h) POSOCO and CTU may use PV analysis or any other suitable method which includes reactive power while calculating TTC/ATC.

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Annexure-I

CENTRAL ELECTRICITY REGULATORY COMMISSION
4th Floor, Chandralok Building, 36, Janpath,
New Delhi - 110001

Date: 10/07/2017

No. 19/5/2017/E/PoC Review

OFFICE ORDER

Subject : Constitution of Task Force to review of the framework of Point of Connection (PoC) Charges

The Commission, on 19th May, 2017 reviewed the framework of Point of Connection (PoC) Charges and noted that the regulations in the context were issued in 2010 and have been modified from time to time keeping in view the demands of time and concerns of various stakeholders. The Commission has decided to constitute a Task Force chaired by a Member of CERC and consisting of representatives from CERC, CEA, POSOCO, CTU and other concerned to review the framework of Point of Connection (PoC) charges so as to align transmission pricing with the future growth strategy of the sector.

2. In view of the above the Commission has decided to constitute a Committee with following compositions to review the prevailing framework of transmission pricing mechanism i.e. Point of Connection (PoC) charges:

(1) Shri A.S. Bakshi, (Member, CERC)
(2) Representative of CEA.
(3) Representative of CTU.
(4) Representative of POSOCO.
(5) Shri S.C.Shrivastava, Chief(Engg), CERC
(6) Shri M.K.Anand, Chief (Finance), CERC
(7) Jt Chief (Engg), CERC- Member Secretary

The Committee may invite representatives of stakeholders or a well known expert, as and when required by the Committee. The Committee may seek assistance from CTU & NLDC for study and analysis purpose.

3. The Terms of Reference of the committee is as follows:

(a) To critically examine the efficacy of the existing PoC mechanism to see whether the mechanism has served its purpose as enshrined in Tariff Policy namely sensitive to distance ,direction and quantum of flow;

(b) The role of the existing mechanism in improving the power market;

(c) Deficiency in the existing mechanism if any, and in the light of issues and concerns of various stakeholders

(d) To assess the status of availability of data and data telemetry in order to facilitate shifting towards actual scenario than the estimated scenario as done currently;

(e) Suggest modifications required in the existing mechanism in due consideration of future market scenario, large scale capacity addition of renewable, introduction of GNA concept for transmission planning, introduction of ancillary services and reserves, supported by international experience in this regard;

(f) Specify Reliability benefit in a large connected grid and provide methodology for determination of quantum of Reliability Support Charges and it's Sharing by constituents and to provide Methodology of Sharing of HVDC Charges by constituents;

(g) Final Recommendations on Transmission pricing;

(h) In addition the Taskforce shall also study the following and make recommendations to the Commission:

i. To assess the utilisation of transmission system and suggest measures to improve the utilisation of transmission system;

ii. To assess the reactive power requirement in integrated grid and examine the adequacy of available reactive power management resources;

iii. To assess the available transfer capability and the measures to improve the same;

iv. Any other relevant issue,

4. Committee may complete the work and submit report to the Commission within 6 months from the date of issue of this office order.

(SANOJ KUMAR JHA)
Secretary

Copy to:
1. Chairperson, CEA
2. C.O.O., CTU
3. C.E.O., POSOCO

With a request to nominate a person and provide his contact details including e-mail address within one week.

NTT:

Copy for information to:

PPS to Chairperson
PA to M(AKS),M (ASB),M (MK),

CENTRAL ELECTRICITY REGULATORY COMMISSION
3rd & 4th Floor, Chanderlok Building, 36 Janpath
New Delhi-110001

No. 19/5/2017/E/POC Review

Dated 06.08.2018

OFFICE ORDER

Subject:- **Continuation of Task Force to review the framework of Point of Connection (PoC) Charges.**

The Commission vide its Office Order dated 10.7.2017 formed a Committee under the Chairmanship of Shri A.S. Bakshi, Member, CERC as Chairperson of the Task Force to review the framework of Point of Connection (PoC) Charges.

2. Consequent upon superannuation of Shri A. S. Bakshi on 23.7.2018, it has been decided that Shri A.S. Bakshi shall continue as Chairperson of the Task Force, in order to maintain continuity in deliberation and early finalization of report.

3. The Task Force shall complete the work and submit its report to the Commission by 31.10.2018.

06/08/18
(SANOJ KUMAR JHA)
Secretary

Copy to:-

1. Shri A. S. Bakshi, Chairperson of the Task Force
2. Shri M.K. Anand, Chief (Finance), CERC
3. Shri S.C. Shrivastava, Chief (Engg.), CERC
4. Shri S.S Barpanda, AGM, NLDC
5. Shri Ravinder Gupta, Chief Engg., PSP&PA-I, CEA
6. Shri Dilip Rojeker, AGM (CTU-Plg.), POWERGRID
7. Ms. Manju Gupta, AGM (CTU-Plg.), POWERGRID
8. Ms. Shilpa Agarwal, Joint Chief (Engg.), CERC

Copy for information to:-

PPS to Chairperson

PS/PA to M(AKS)/M(MKI)