Formulating Pricing Methodology for Inter-State Transmission in India

Central Electricity Regulatory Commission

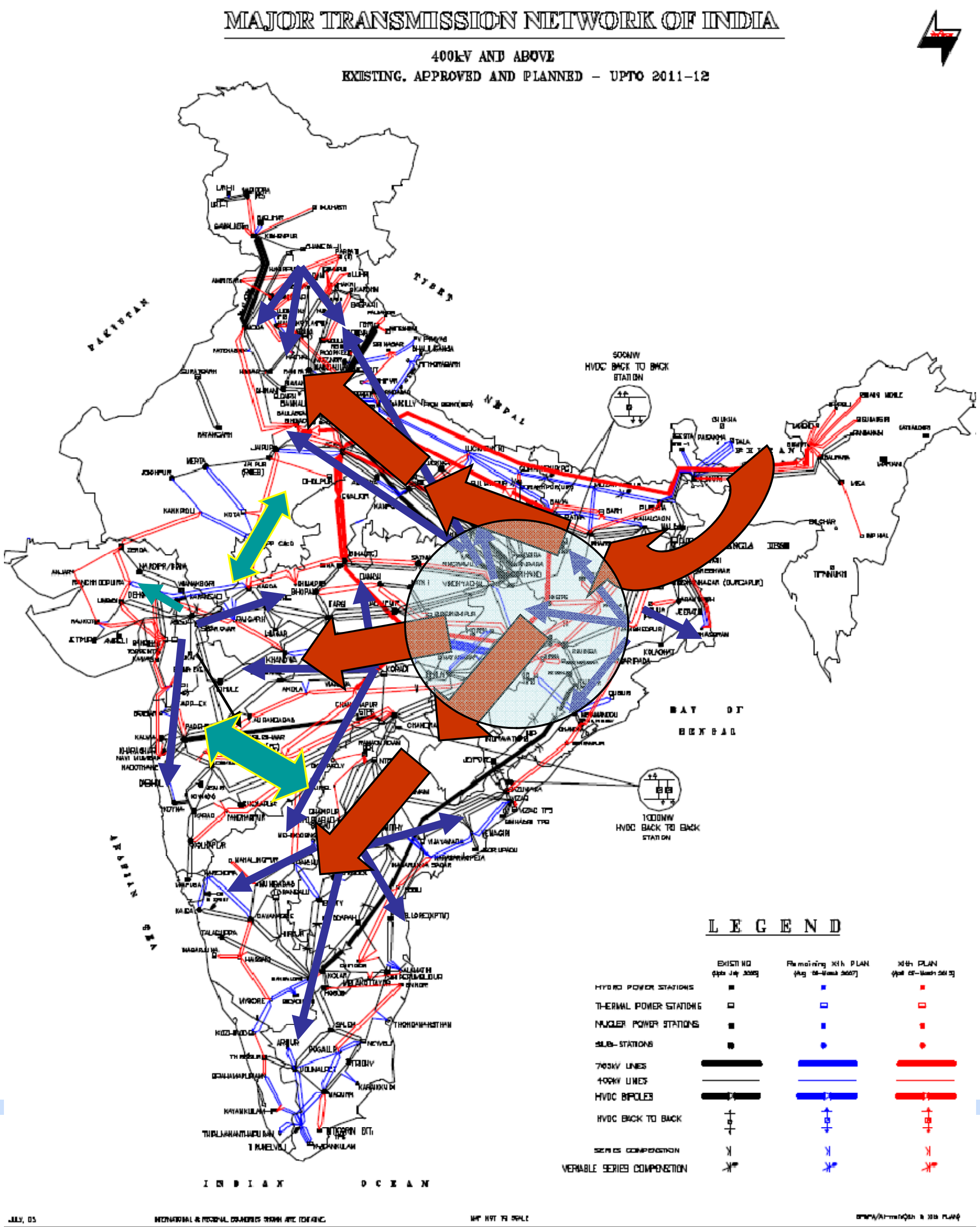
Agenda

- Policy Mandate
- Tariff Design Options
- Selection of the preferred framework
  - Illustration using 6-Bus example
- Implementation of the preferred framework
- Discussion of Results

Tariff Policy Mandate

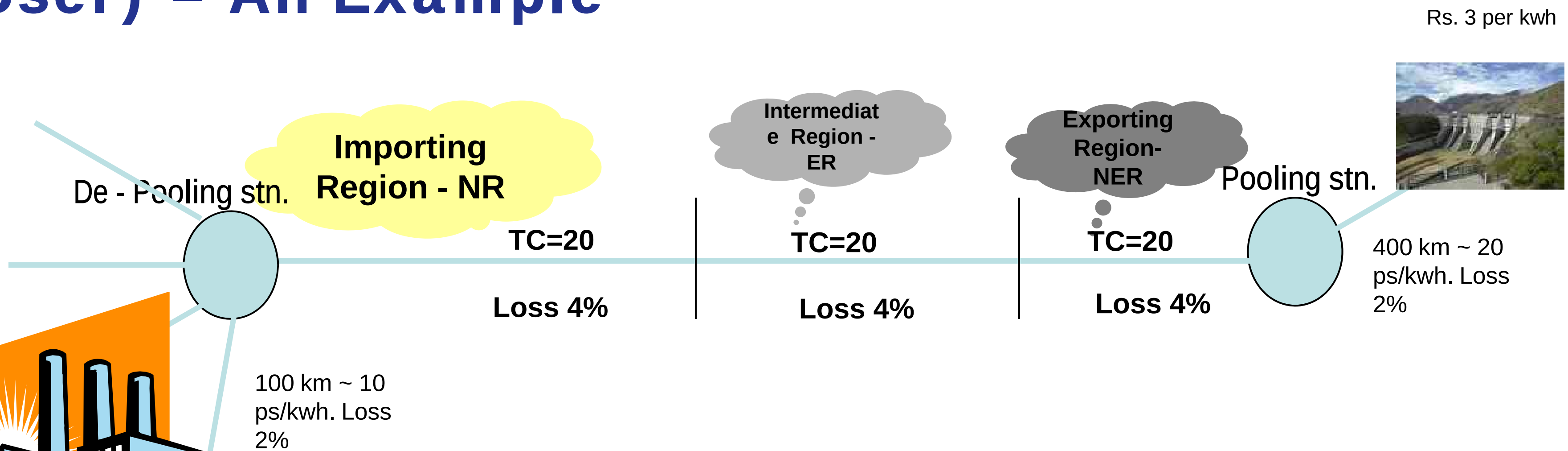
- Para 7.1 (2)
  - Transmission charges should be sensitive to
    - Distance
    - Direction, and
    - Quantum of flow
- Para 7.1 (3)
  - Network users should share transmission costs in proportion of their respective utilization of the transmission network
- Para 7.1 (4)
  - Prior Agreement with the beneficiaries should not to be a pre-condition for transmission capacity expansion
  - Network expansion in consonance with the National Electricity Plan and in consultation with stakeholders, after due regulatory approvals

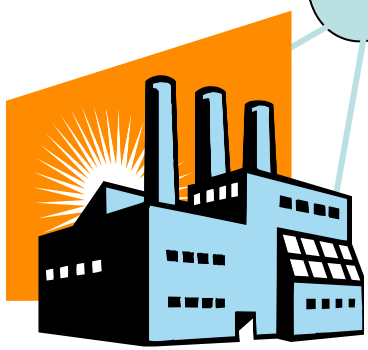
PGCIL Map (Till 2012)



- Evolution of high density coridors between NE/E to W and N
- Frequency integration of all regions currently, except South
- South to be integrated better after 2012. Single national grid to become operational
- Predominantly unidirectional flows **for long term transactions**

Pricing under Postage Stamp (Long term User) – An Example

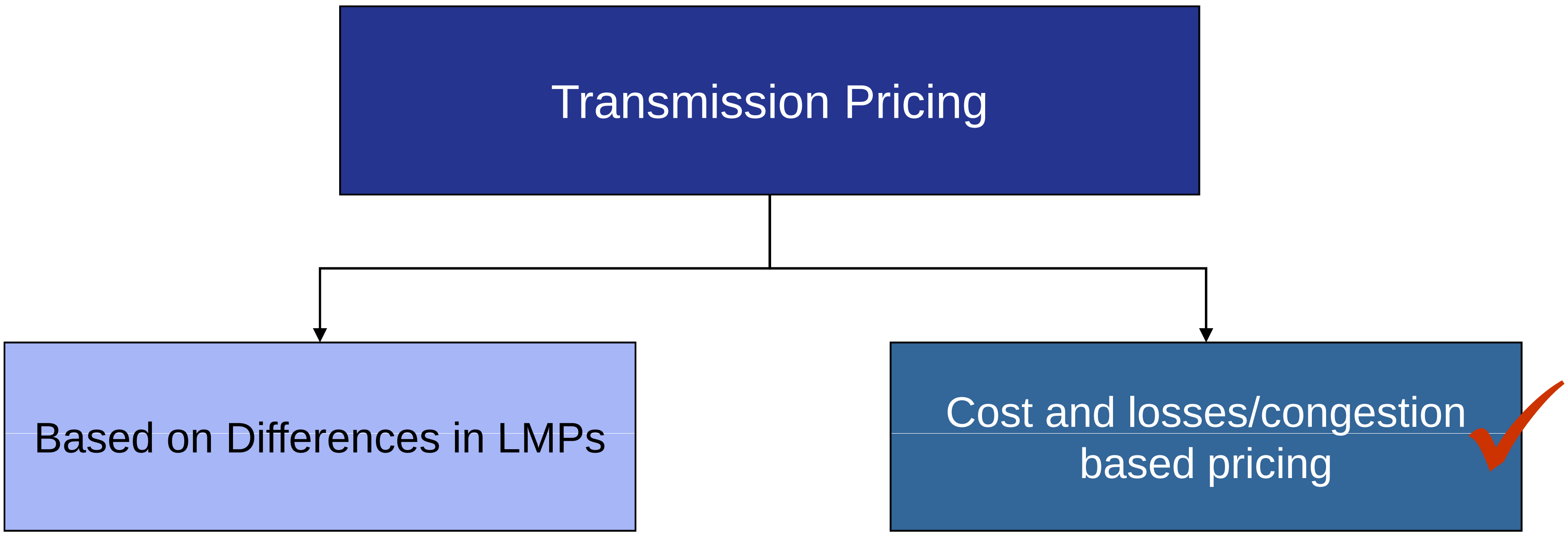




- Cost of delivery
  - Cost at Generator Terminals – 300 ps/kwh
  - Transmission costs to load centre – 90 ps/kwh
  - Cost of losses – 74.28 ps/kwh
  - Final costs – 464.28 ps/kwh
- Much of the cost levels are genuine. There could even be element of cross-subsidisation of new transmission costs by existing beneficiaries
- If new line costs are loaded on to first user(s), then the cost of delivery can be prohibitive
- There could be a tendency of over-estimation of losses
- **Hence the need to ensure a *fairer* allocation**

Tariff Design Options

Overall Options



For India cost and congestion based pricing is relevant on account of design and operations of the power markets

Structure of Transmission Charges

- Transmission charges consist of
  - Charges for dedicated assets
  - Transmission Network Use of System Charges (for the meshed network)
  - Common charges
- The focus of the ensuing discussion is:
  - Allocation of Transmission Network Use of System charges
- Purpose of the pricing approach is to allocate the transmission charges

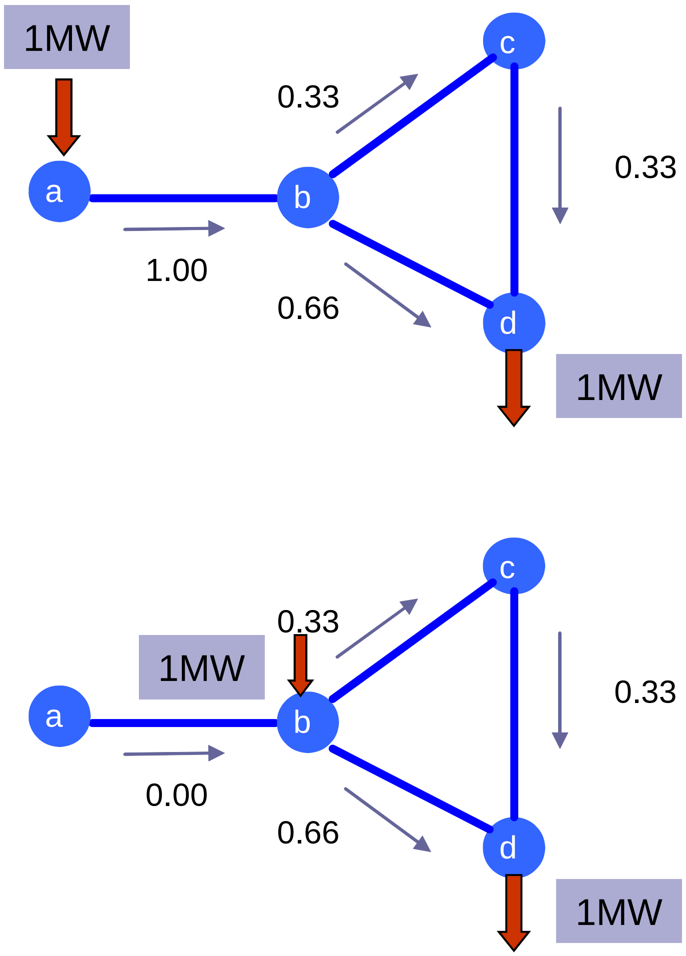
Options for allocation of Transmission Network Use of System (TNOUS) Charges

- Marginal Participation Method
- Average Participation Method
- Zone-to-zone Method

Why Marginal Participation Method?

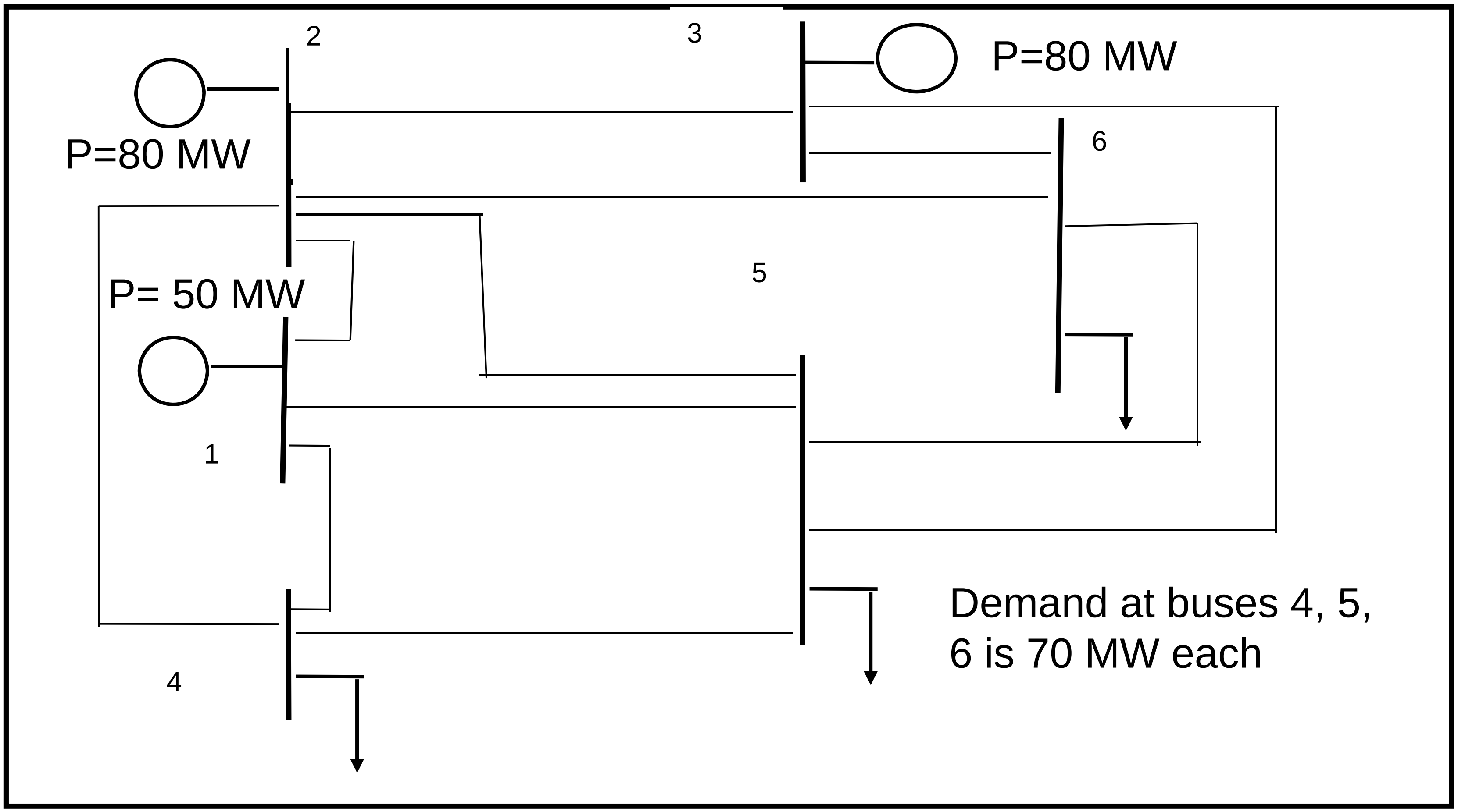
- Addresses the policy mandate. The charges determined
  - Are sensitive to Distance
  - Are sensitive to Direction
  - Are sensitive to Quantum of Flow
  - Obviate the need for BPTAs for capacity expansion in Transmission
- The charges are based on incremental utilization of network assessed through load flows
- Allocators less arbitrary - Provides better locational signals as compared with AP method
- Is backed by considerable international experience

Marginal Participation Method (Point Tariff)



- Based on the extent to which a unit increase in power injected into and withdrawn from the grid at each node affects the various network elements
- This assessment produces the 'marginal participation' of each node in the power flow over each network element
- Total participation at each node is obtained by multiplying its marginal participation by net power injection/withdrawal at each node
- This method requires selection of a slack (reference) bus and allocations are very sensitive to the location of the slack bus

6 Bus Example



6 Bus Example: An implementation of MP Method

- Base Case Line Flows
- Line flows with 1 MW increment / withdrawal at Generation / Demand Buses

	Line 1-2	Line 1-4	Line 1-5	Line 2-3	Line 2-4	Line 2-5	Line 2-6	Line 3-5	Line 3-6	Line 4-5	Line 4-6
Base Case	0.025	-0.3	-0.225	0.0875	-0.325	-0.25	-0.2875	-0.3375	-0.375	0.075	-0.0375
G1	0.0219	-0.3033	-0.2286	0.0868	-0.3253	-0.2506	-0.289	-0.3374	-0.3758	0.0747	-0.0385
G2	0.0265	-0.3008	-0.2257	0.086	-0.3274	-0.2522	-0.2899	-0.3382	-0.3758	0.0751	-0.0376
G3	0.0257	-0.3008	-0.2249	0.0906	-0.3265	-0.2506	-0.2878	-0.3411	-0.3783	0.076	-0.0372
D4	0.0257	-0.3031	-0.225	0.0886	-0.3288	-0.2506	-0.2873	-0.3392	-0.376	0.0781	-0.0367
D5	0.0253	-0.3006	-0.227	0.0878	-0.3259	-0.2523	-0.2882	-0.3401	-0.376	0.0736	-0.0359
D6	0.0244	-0.3006	-0.2262	0.0874	-0.325	-0.2506	-0.2911	-0.338	-0.3785	0.0744	-0.0405

6 Bus Example

- Differences in Line Flows

	Line 1-2	Line 1-4	Line 1-5	Line 2-3	Line 2-4	Line 2-5	Line 2-6	Line 3-5	Line 3-6	Line 4-5	Line 4-6
G1	-0.0031	0.0033	0.0036	-0.0007	0.0003	0.0006	0.0015	-0.0001	0.0008	-0.0003	0.001
G2	0.0015	0.0008	0.0007	-0.0015	0.0024	0.0022	0.0024	0.0007	0.0008	0.0001	0.0001
G3	0.0007	0.0008	-0.0001	0.0031	0.0015	0.0006	0.0003	0.0036	0.0033	0.001	-0.0003
D4	0.0007	0.0031	0	0.0011	0.0038	0.0006	-0.0002	0.0017	0.001	0.0031	-0.0008
D5	0.0003	0.0006	0.002	0.0003	0.0009	0.0023	0.0007	0.0026	0.001	-0.0014	-0.0016
D6	-0.0006	0.0006	0.0012	-0.0001	0	0.0006	0.0036	0.0005	0.0035	-0.0006	0.003

6 Bus Example

Computation of the total change in line flows: Multiply change in flows with total MW injected

	Line 1-2	Line 1-4	Line 1-5	Line 2-3	Line 2-4	Line 2-5	Line 2-6	Line 3-5	Line 3-6	Line 4-5	Line 4-6
G1	-0.155	0.165	0.18	-0.035	0.015	0.03	0.075	-0.005	0.04	-0.015	0.05
G2	0.12	0.064	0.056	-0.12	0.192	0.176	0.192	0.056	0.064	0.008	0.008
G3	0.056	0.064	-0.008	0.248	0.12	0.048	0.024	0.288	0.264	0.08	-0.024
D4	0.049	0.217	0	0.077	0.266	0.042	-0.014	0.119	0.07	0.217	-0.056
D5	0.021	0.042	0.14	0.021	0.063	0.161	0.049	0.182	0.07	-0.098	-0.112
D6	-0.042	0.042	0.084	-0.007	0	0.042	0.252	0.035	0.245	-0.042	0.21

6 Bus Example

All flow which decongest the network set to zero

	Line 1-2	Line 1-4	Line 1-5	Line 2-3	Line 2-4	Line 2-5	Line 2-6	Line 3-5	Line 3-6	Line 4-5	Line 4-6
G1	0	0.165	0.18	0	0.015	0.03	0.075	0	0.04	0	0.05
G2	0.12	0.064	0.056	0	0.192	0.176	0.192	0.056	0.064	0.008	0.008
G3	0.056	0.064	0	0.248	0.12	0.048	0.024	0.288	0.264	0.08	0
D4	0.049	0.217	0	0.077	0.266	0.042	0	0.119	0.07	0.217	0
D5	0.021	0.042	0.14	0.021	0.063	0.161	0.049	0.182	0.07	0	0
D6	0	0.042	0.084	0	0	0.042	0.252	0.035	0.245	0	0.21
Sum	0.246	0.594	0.46	0.346	0.656	0.499	0.592	0.68	0.753	0.305	0.268

6 Bus Example

Marginal Participation Factor of generation / demand at each bus

ARR (Rs/hr)	7488.584	7488.584	7488.584	7488.584	7488.584	7488.584	7488.584	7488.584	7488.584	7488.584	7488.584
	Line 1-2	Line 1-4	Line 1-5	Line 2-3	Line 2-4	Line 2-5	Line 2-6	Line 3-5	Line 3-6	Line 4-5	Line 4-6
G1	0.00%	27.78%	39.13%	0.00%	2.29%	6.01%	12.67%	0.00%	5.31%	0.00%	18.66%
G2	48.78%	10.77%	12.17%	0.00%	29.27%	35.27%	32.43%	8.24%	8.50%	2.62%	2.99%
G3	22.76%	10.77%	0.00%	71.68%	18.29%	9.62%	4.05%	42.35%	35.06%	26.23%	0.00%
D4	19.92%	36.53%	0.00%	22.25%	40.55%	8.42%	0.00%	17.50%	9.30%	71.15%	0.00%
D5	8.54%	7.07%	30.43%	6.07%	9.60%	32.26%	8.28%	26.76%	9.30%	0.00%	0.00%
D6	0.00%	7.07%	18.26%	0.00%	0.00%	8.42%	42.57%	5.15%	32.54%	0.00%	78.36%

6 Bus Example

- Computation of transmission charges at each node

	Line 1-2	Line 1-4	Line 1-5	Line 2-3	Line 2-4	Line 2-5	Line 2-6	Line 3-5	Line 3-6	Line 4-5	Line 4-6	Rs/hr	Rs/ kW/ hr
G1	0.00	2080.16	2930.32	0.00	171.23	450.22	948.72	0.00	397.80	0.00	1397.12	8375.57	0.17
G2	3652.97	806.85	911.65	0.00	2191.78	2641.26	2428.73	616.71	636.48	196.42	223.54	14306.40	0.18
G3	1704.72	806.85	0.00	5367.54	1369.86	720.34	303.59	3171.64	2625.48	1964.22	0.00	18034.24	0.23
D4	1491.63	2735.73	0.00	1666.53	3036.53	630.30	0.00	1310.50	696.15	5327.94	0.00	16895.32	0.24
D5	639.27	529.50	2279.13	454.51	719.18	2416.16	619.83	2004.30	696.15	0.00	0.00	10358.02	0.15
D6	0.00	529.50	1367.48	0.00	0.00	630.30	3187.71	385.44	2436.52	0.00	5867.92	14404.87	0.21

Application of the Marginal Participation Method

- Data Input
  - Nodal generation information
  - Nodal demand information
  - Transmission circuits between these nodes
  - Technical characteristics of each network branch: Resistance, Reactance, line charging and capacity of each network branch
  - The associated lengths of each line
  - Identification of reference nodes

Data Description - Network Data

- 1699 bus all India transmission system which corresponds to 2011-2012 scenario.
- The data for the analysis was provided by Central Electricity Authority (CEA)
- The system has 805 loads, 499 generators.
- The transmission system has a total length of 188834 ckt kms with 3158 ckt kms of 765 kV, 86718 ckt kms of 400 kV, 98432 ckt kms of 220 kV, and 527 ckt kms of 132 kV lines.
- There are 10 HVDC lines with 8300 kms of length and having capacity of 6600 MW.

Data Description - Scenarios and Generation Levels

Season	Generation (MW)	Duration
Winter – Peak	153689	Nov, Dec, Jan, Feb – 8 hours per day
Winter – Other than peak	109748	Nov, Dec, Jan, Feb – 16 hours per day
Summer - Peak	155490	Mar, Apr, May, Jun – 8 hours per day
Summer – Other than peak	118563	Mar, Apr, May, Jun – 16 hours per day
Monsoon - Peak	139947	Jul, Aug, Sep, Oct – 8 hours per day
Monsoon – other than peak	109779	Jul, Aug, Sep, Oct – 16 hours per day

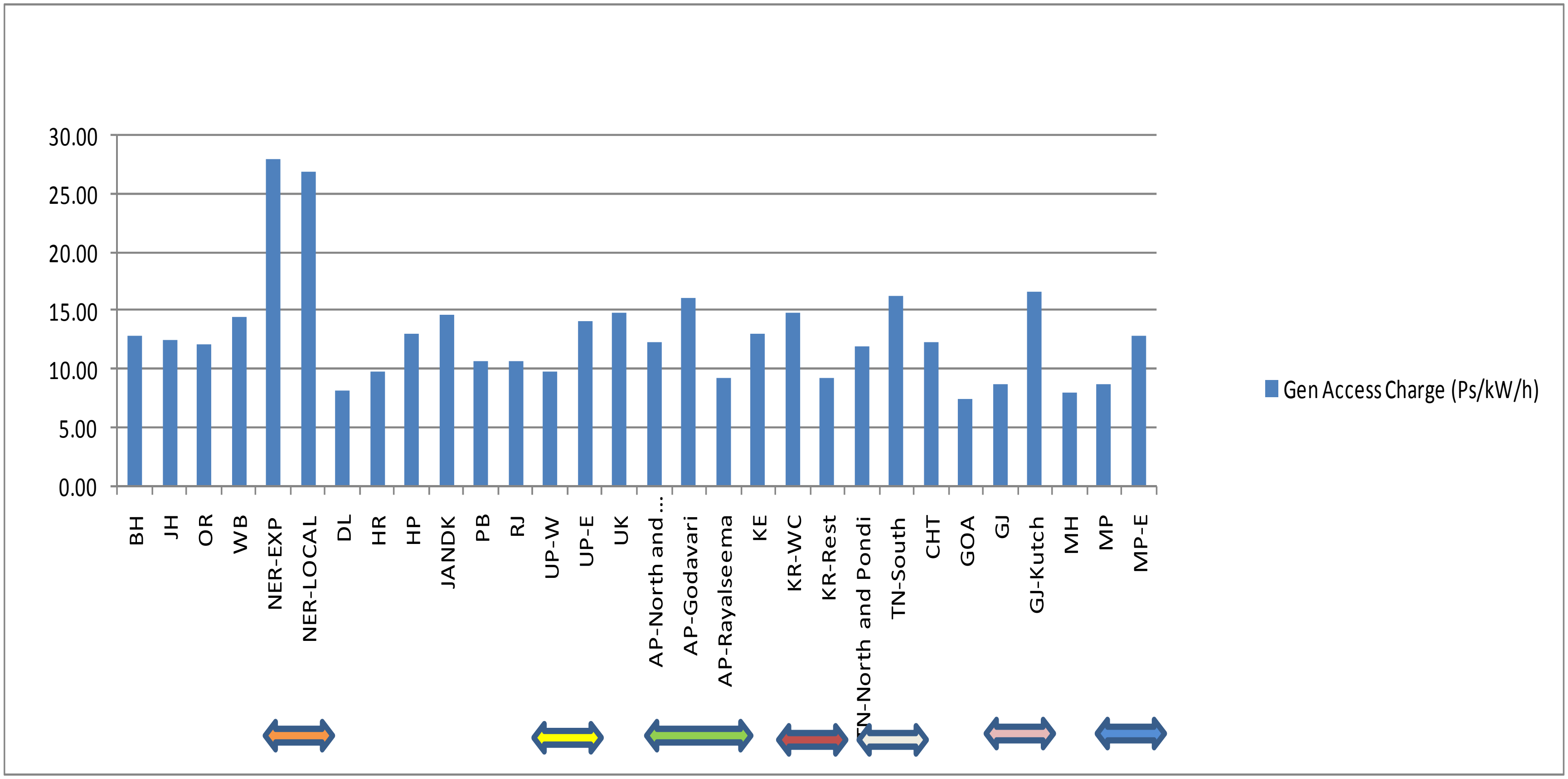
Steps Followed in the implementation of the MP Method

- Full AC load flow was run – results matched with those obtained by CEA
  - The real power flows on various lines and the voltage angles between various nodes matched closely with the data provided by CEA.
- Treatment of HVDC lines
  - Voltage angles are computed at each of the terminal buses. Given the power flow in the base case and the voltage angles, the reactance of equivalent AC line is determined. AC line with the parameters so determined is used for the determination of transmission charges.
- MP Method Implemented using DC load flow
  - The ‘benchmark’ capital cost of lines and the norms of CERC were used for computation of ARR

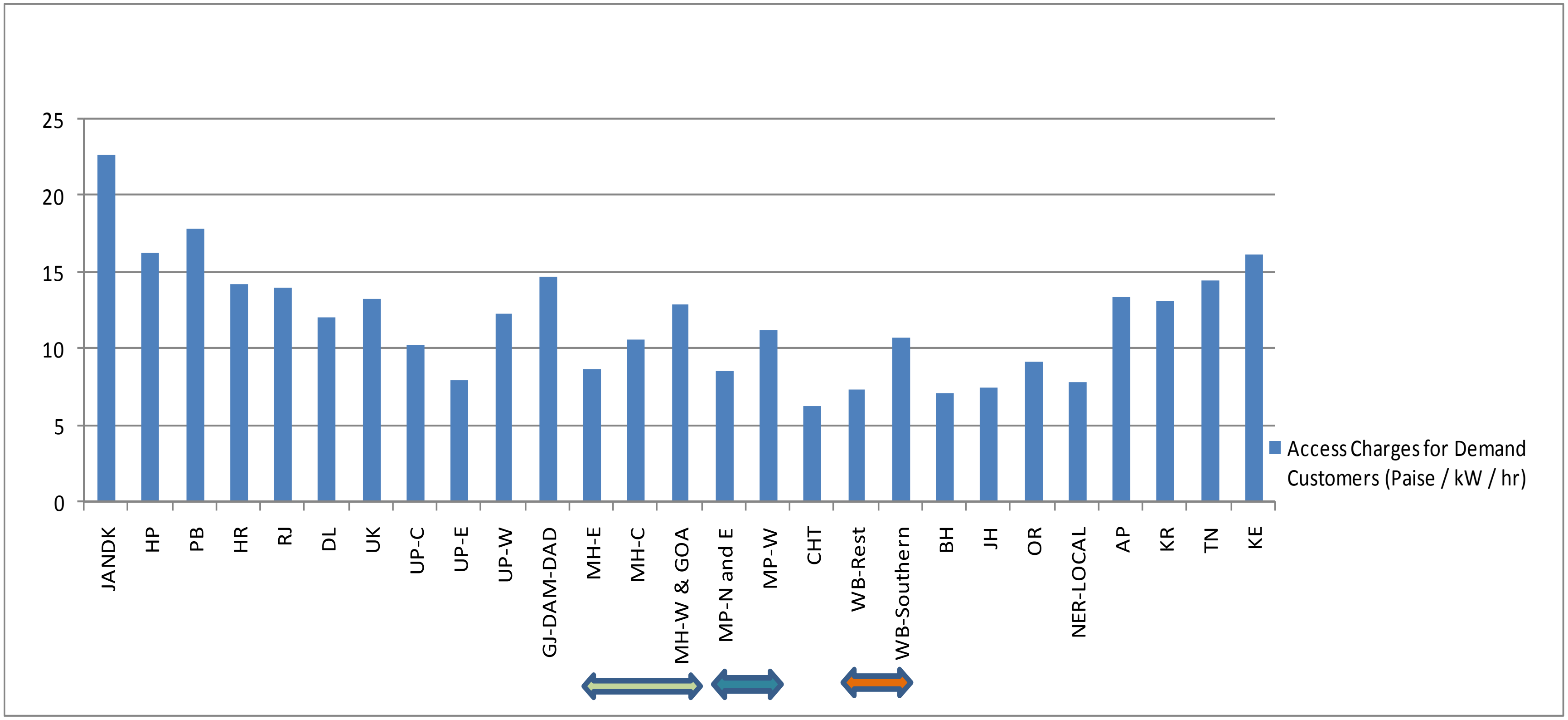
Creation of Zones

- Zones contain relevant nodes whose marginal costs (as determined from the output from the computation model) are within a logical range.
- The nodes within zones are geographically and electrically proximate.
- Generation and demand are separately zoned
- The total number of generation access zones created is 30 and the number of demand access zones is 27.

Transmission Access Charges Payable by Generators



Access charges payable by Demand Customers



How does the MP method address the policy mandate? – Distance and Direction sensitivity

- The access charges in Bihar, Jharkhand and Orissa are in the same range
  - owing to the fact that power normally flows unidirectionally from this region to NR, WR and SR.
- Power from power plants in West Bengal flow into both NR and NER thereby leading to slightly higher charges as compared to Bihar.
- Transmission access charges for generators in NER are high
  - long transmission lines from hydro stations to the grid pooling stations (more than 100 kms and in some instances more than 200 kms).
- A generator in Delhi intending to sell power to a customer in Central Uttar Pradesh would decongest the network – hence pays less
- Generation access charges in Uttarakhand are again slightly high because of long lines from the Hydro Stations.

Impact on network users - Inter-regional network users

- Inter-regional transfers under the proposed mechanism are relatively cheaper as compared to the present mechanism.
  - Avoids Pancaking
  - Transfers from Jharkhand to Delhi:
    - Under MP Method: 24 paise / kWh
    - Current Postage stamp charge: 32 paise / kWh (Approx)
  - Transaction from Jharkhand to Andhra Pradesh
    - 26 paise/kWh,
    - Jharkhand to Karnataka 25.6 paise/kWh,
    - Jharkhand to Tamil Nadu 27 paise/kWh and
    - Jharkhand to Kerala 28.60 paise/kWh
    - Existing charge: 32-36 paise/kWh.
  - Transaction from NER to Kerala
  - 44 paise/kWh
  - Current Mechanism: 48-50 paise/kWh.

Impact on network users - Intra-regional network users

- Chattisgarh to Maharashtra-East
  - 21 ps/kWh
  - Current Charge: 20 paise / kW / hr.
- West Bengal to Bihar
  - 21.56 paise / kWh
  - Current Charge: 20.6 paise / kW / hr
- To demand customers in Andhra Pradesh
  - from Generators in AP-Rayalseema zone: 22.53 paise/kW/hr to be paid as access charges
  - from generators in AP-North and Central, AP-Godavari: 25 paise/kWh and 29 paise/kWh respectively
  - Current Charges: 25.14 paise / kW / hr
- Higher transmission access charges attributable to generators in APGodavari are because of long transmission lines (more than 100 kms) from hydro power stations.

Transmission charges for hydro and wind generators

- The key low carbon generators in the Indian power system are the hydro and wind resources.
- Access charges for generators in NER under MP method:
  - 28.1 paise / kW / hr
  - If it were reduced to : 25 paise / kW / hr
  - Additional burden on other grid connected entities: 0.05 paise/kW / hr.
- It may be necessary and indeed worthwhile to reduce the access charges for generators in NER by a small but meaningful amount
  - to encourages more generation capacity in the region
  - make market access more attractive (without altering Locational signals significantly)
  - impact on the rest of the system users is negligible.

Formulating Pricing Methodology for Inter-State Transmission in India – Implementation Issues

Central Electricity Regulatory Commission

What is the information required to determine transmission charges using MP method?

- Nodal generation information
- Nodal demand information
- Transmission circuits between these nodes
- Technical characteristics of each network branch: Resistance, Reactance, line charging and capacity of each network branch
- The associated lengths of each line

Who will provide this information?

- Nodal generation information
  - All generators connected to ISTS
  - SLDCs in case of generators connected to the ISTS network owned by STUs
- Nodal demand information
  - Beneficiary demand customers (distribution utilities/ SEBs / STUs)
- Transmission Data
  - CTU / STUs / SEBs
- This information is currently used by reliability coordinators in RLDCs

How frequently would the transmission charges be revised

- The charges would be revised every six months initially
- Subsequently, once enough experience is gained, the revisions can be made every year

Who will compute the transmission charges?

- An appropriate agency designated by CERC will compute the transmission charges as per approved methodology
- The charges will be notified by CERC after review

When will data be submitted and what will be the frequency of submission of the data?

- The data for computation of transmission access charges applicable from April 1 to September 30 of a financial year will be submitted by September 30 of the preceding FY (i.e. 6 months in advance)
- Similarly, for charges applicable from October 1 to March 31, the data will have to be submitted by March 31

What data will be provided by the Generators and Demand and how will the same be used?

- Generation levels committed by each generator under specific – seasonal peak and other than peak conditions identified a-priori
- Similarly, nodal demand data will be based on forecasts by beneficiary utilities (SEBs / distribution utilities) will be utilised
- NLDC will validate the information supplied
- Based on the nodal information obtained the load flow based simulation would be undertaken
- Approved transmission capacity for injection/ transaction by each generator/demand customer would form basis for commercial transactions

Which transmission data will be used for computation of transmission charges?

- ISTS transmission circuit data is to be supplied by the CTU based on transmission expansion plan
- Data of the STU lines considered for Inter-state transmission of electricity will be supplied by the STU, (along with the revenue requirement) with approvals of appropriate SERC

How will the transmission charges will be charged?

- Based on the generator, demand and network related information obtained, TNUoS will be determined as Rs/MW in each season at each node
- The nodal data would be “zoned” thereafter as per the identified zonalisation criteria.
- Notification of zones and the corresponding charges by the CERC would be in advance of actual implementation

How will transmission charges capture the seasonal changes ?

- The transmission use of the system charges would be fixed for
  - each season, and
  - peak and other than peak periods
- Charges applicable will be multiplied by MW capacity requisitioned/contracted by each user for each season and peak and other than peak
- The capacity contracted would remain unchanged during a 6 month period at a given node
- In case the contracted demand is exceeded, the actual MW recorded at the node during the month will apply

How would network service providers (CTU, STUs and IPTCs) be compensated

- CTU / RLDCs would be required to maintain an account of the transmission charges to be collected from each user of the ISTS.
- The bills for the transmission charges for use of the ISTS would be raised by RPCs based on RLDC data.
- The mechanism is similar to that adopted for collection and disbursement of UI pool charges
  - As with UI, the transmission pool collection agency would not be liable for under / delayed payment

What is Connection and Use of System Agreement?

- Users of the ISTS will be governed by the Connection and Use of System Agreement (CUSA) - a multi-party agreement
- Grid connected entities to open an escrow with a depository nominated by CTU/RLDCs
- CTU/RLDCs would compensate on a monthly basis all the transmission service providers based on their approved ARR.
  - This would include the CTU, the IPTCs or any state owned line designated to be a part of the ISTS
  - This kind of arrangement is already in place for the Tala transmission link and for STU lines considered in ISTS

How is delay in injection / withdrawal from the Grid treated?

- The transmission charges depend on the chargeable capacities committed by the generators / demand customers (6 monthly)
- CUSA would identify the force-majeure conditions under which the delay by grid connected entities would not be charged.
- Under all other conditions the charges would be paid by the grid connected entities.
- If synchronization of new generator is delayed, it will be made to bear the burden of the default per CUSA
- Similarly, the demand customer will bear the burden of delay in the materialization of demand

How is advancement of injection / withdrawal treated?

- In case a new generator is synchronised before schedule, it will be required to obtain short term access for such period
- Similar will be the case with demand
- Access would be granted at the same level of charges, subject to network availability
- Amount recovered in excess would be credited to the Transmission Charges pool for adjustments in subsequent periods

How is the delay in creation of transmission capacity treated?

- The Transmission Utilities would be signatories to CUSA
- In case of a delay (non force-majeure), transmission utility would be governed by the terms of the CUSA
- The mechanism proposed is identical to the system being evolved for the IPTCs who are awarded projects through competitive bidding

How is violation of CUSA by Generators treated?

- If the actual generation increases above the forecast for the charging season
  - the party will be liable for the additional charge incurred for the full season
- In case the generation is in excess of the contracted transmission capacity (but within permissible limits), the billing would be as per actual generation
- Generation significantly higher than the access capacity contracted (either short or long term) could attract penal charges
- No recalculation is to be done in the cases where the generation is below the forecast generation level

How is violation of CUSA by Demand Customers treated?

- The beneficiary utilities are expected to submit reasonable demand forecasts.
- The designated agency (NLDC) would determine if the forecast is reasonable and may alter the forecast if unreasonable/infeasible
- In the event of a beneficiary drawing more than the scheduled forecast, penal provisions (similar to generators) will apply.