विद्युत् नियमन आयोग

(विद्युत् नियमन आयोग ऐन, २०७४ बमोजिम स्थापित स्वायत नियमनकारी निकाय)

(प्रशासन शाखा)

प.सं.: ०८२/८३
च.नं.: प्र./ ३८०

मितिः २०८२।०७।२०
ने.सं. ११४६ कछलागा प्रतिपदा

राय, सल्लाह, सुझाव तथा प्रतिक्रिया उपलब्ध गराइदिने सम्बन्धी सूचना ।

प्रस्तुत विषयमा यस आयोगद्वारा तयार पारिएको **Draft Discussion Paper on Sharing of Cost and Losses of Dedicated Transmission Lines** को यसै साथ संलग्न मस्यौदाका सम्बन्धमा ३० दिन भित्र राय, सल्लाह, सुझाव तथा प्रतिक्रिया उपलब्ध गराइदिनुहुन सम्पूर्ण सरोकारवालाहरूमा अनुरोध छ ।

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ELECTRICITY REGULATORY COMMISSION

Sano Gaucharan, Kathmandu, Nepal

A Discussion Paper on

Sharing of Cost and Losses of Dedicated Transmission Lines

CONTENT

ABBREVIATIONS

ATC	Annual Transmission Charge
BOOT	Build, Own, Operate and Transfer
CAPEX	Capital Expenditure
CERC	Central Electricity Regulatory Commission
COD	Commercial Operation Date
CF	Capacity Factor
CRF	Capital Recovery Factor
CTU	Central Transmission Utility
CUF	Capacity Utilisation Factor
DTL	Dedicated Transmission Line
EU	European Union
ENTOS-E	European Network of Transmission System Operators for Electricity
FERC	Federal Energy Regulatory Commission
IOWC	Interest on Working Capital
IPP	Independent Power producer
ISTS	Inter State Transmission System
O&M	Operation and Maintenance
POC	Point of Connection
PPA	Power Purchase Agreement
PPP	Public Private Partnership
RAB	Regulatory Asset Base
ROE	Return on Equity
RTO	Regional Transmission Organisation
SAARC	South Asian Association for Regional Co-operation
SERC	State Electricity Regulatory Commission
SLA	Service Level Agreement
SPV	Special Purpose Vehicle

TSA	Transmission Service Agreement
TSO	Transmission System Operator
UTC	Co-ordinated Universal Time
WACC	Weighted Average Cost of Capital

1. Introduction

Nepal has recently made transition from acute deficit system to seasonally surplus system with the accelerated development of hydro power. Hydro power dominates the generation sector of Nepal. The hydro power stations are mostly owned by IPPs. The hydro power stations are run of the river type. As a result, the generation availability is dependent on season. There is wide variation in availability of generation between wet season and dry season. Unit size of hydro power stations is generally small and below 100 MW. Hydro potentials are concentrated in some geographically dispersed locations. Power sector of Nepal is dominated by NEA which is a vertically integrated entity having its own generation, transmission and distribution system. NEA is the sole off-taker of hydro power produced by IPPs. For this, the IPPs enter PPAs with NEA. Sale of power through PPAs is on take or pay basis. This gives IPPs a comfort of assured return. While executing the PPA, NEA indicates the injection point of power. Cost relating to transmission charges and the losses therein in the dedicated transmission line are borne by IPPs. As several generators are concentrated in the same geographical area, drawing separate dedicated transmission line for each generator is not operationally, commercially and technically feasible. Further, required transmission corridor may also not be available. Therefore, an integrated approach for transmission planning on national level is required. A dedicated transmission line may be planned and constructed for evacuation of power from a group of generating stations located in the same geographical area. However, there will be several issues that need to be addressed for this. These are as follows:

i) Computation Methodology for Annual Transmission Charge (ATC)

ii) The sharing methodology for transmission charges for the dedicated transmission line by the users (Contracted MW, MW-Mile etc.)

iii) Financial treatment for Early Exit, Late Entry, No-Show and Enhancement of Contracted Capacity

iv) The extent of sharing of Grid Reinforcement Charges (Shallow Charging, Deep Charging etc.).

v) Mechanism for sharing of losses

vi) Role of ERC, Nepal with respect to Dedicated Transmission Lines.

This discussion paper discusses in detail the above issues and thereafter, recommends for adoption of approach to address each of these issues in Nepal.

2. Definition & Characteristics of a Dedicated Transmission Line

A. Dedicated Electrical Transmission Lines (DTLs) are transmission assets constructed exclusively for the evacuation of power from specific generation projects or for supplying power to designated consumers. Unlike shared transmission systems, these assets are not part of the common transmission network but are intended for one or a limited set of users.

B. Some Characteristics of Dedicated Transmission Lines:

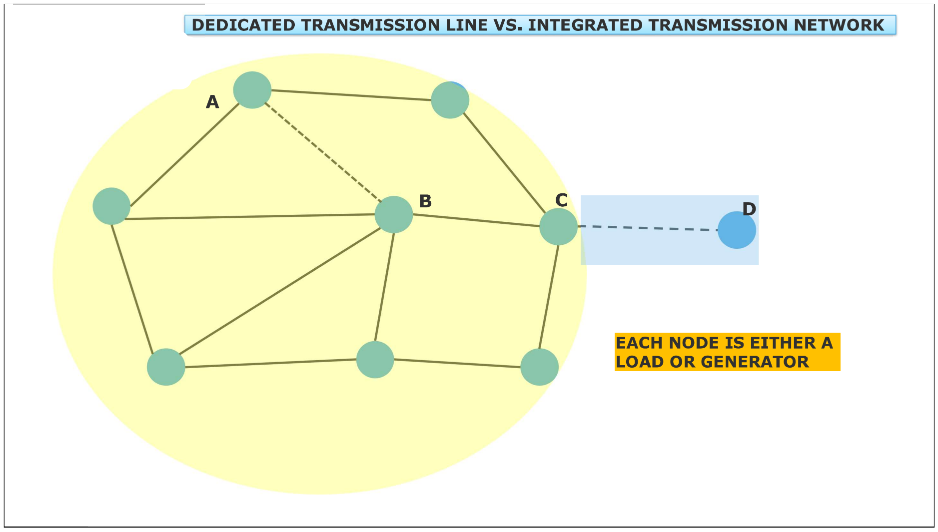
- Designed for a specific, often one-to-one, connection
- Identified users
- Unidirectional flow
- Typically serves a singular purpose, such as transmitting power from a specific source(s) or to a specific load(s).
- Typically owned by a single entity, such as a company or a generating plant or a group of generating plant, for their exclusive use.

C. Some Characteristics of Transmission Network:

- It is a complex system. It is an interconnected web of transmission lines, substations, transformers, and other equipment.
- Its purpose is to transport large amounts of electricity over long distances, often across regions or even countries.
- It comprises of multiple connections and allows for the movement of electricity from various sources to numerous destinations

A transmission line within a transmission network is a part or sub-set of a complex network. Users of the transmission line dynamically changes over time. Flow may be bi-directional.

In essence, *dedicated lines are like private roads, while network lines are like public highways, each serving different needs*.



In the above network diagram. Transmission line C-D is a dedicated transmission line. Transmission line A-B is a network line.

D. **Typical applications —** generator evacuation, industrial connections.

3. Computation Methodology of Annual Transmission Charges (ATC)

Transmission licensees and developers require a transparent mechanism to recover their investments in transmission assets. Two commonly adopted methods are normally used:

1. **Building Block Method** – widely used in regulatory frameworks such as CERC (India), Ofgem (UK), AER (Australia).
2. **Annuity Method (Levelized Cost Method)** – frequently applied in PPP projects, BOOT models, and international cost-benefit assessments.

Both methods aim to ensure adequate cost recovery, financial viability, and fair sharing of charges among users.

A. Building Block Method

Concept

- Annual Transmission Charge (ATC) is computed by summing **individual cost components**.
- Each cost driver is explicitly recognized, making the approach transparent and auditable.

Components

1. **Depreciation** – recovery of capital over the useful life.
2. **Interest on Loan** – calculated on outstanding normative debt.
3. **Return on Equity (RoE)** – allowed return on normative equity.
4. **Operation & Maintenance (O&M) Expenses** – normative or actual costs.
5. **Interest on Working Capital (IOWC)** – carrying cost for receivables, spares, etc.
6. **Taxes, incentives/penalties** – as applicable.

Features

- **ATC changes annually**: interest falls as debt is repaid, while RoE remains constant.
- **Front-loaded tariffs**: higher charges in early years, declining gradually.
- **Transparency**: beneficiaries can see how much goes to debt, equity, depreciation, O&M.
- **Common in regulated transmission systems**.

B. Annuity Method

Concept

- Entire capital cost is recovered through a **single levelized annual charge** using the **Capital Recovery Factor (CRF)** based on Weighted Average Cost of Capital (WACC).
- O&M and other expenses may be added separately (either as levelized or actual escalated amounts).

Formula

$$\textbf{CRF} = r(1+r)^{n} / ((1+r)^{n} - 1)$$

Annualized Capital Recovery=CAPEX X CRF

Where:

- r= Discount rate (WACC = Cost of Debt × Share of Debt + Cost of Equity × Share of Equity)
- n = Asset life (years)

Features

- Produces **constant annual transmission charge** (predictable cash flow).
- **Return on Equity is implicit** in WACC, not shown as a separate line item.
- Often used in **PPP/BOOT models** and **international cost-benefit studies**.
- Suitable when a **uniform tariff profile** is desirable for users.

C. **Comparative Illustration**

Capital Cost = NPR 500 Cr.

Debt-Equity Ratio = 70:30

Debt Rate = 10%

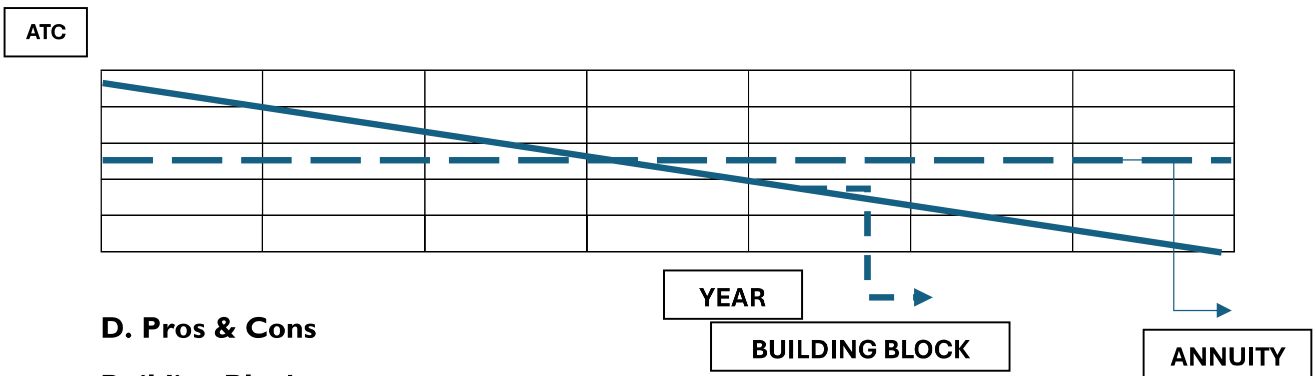
Return on Equity = 16%

Life = 25 years

Aspect	Building Block (Year-1)	Annuity Method (All Years)
Depreciation	NPR18 cr	– (included in annuity)
Interest on Loan	NPR 35 cr	– (included in annuity)
Return on Equity	NPR 24 cr	– (via WACC in CRF)

Aspect	Building Block (Year-1)	Annuity Method (All Years)
O&M	NPR 7.5 cr	NPR 7.5 cr (explicit)
ATC	**NPR 84.5 cr**	**NPR 71.2 cr**
Year-on-Year Trend	Declining over 25 yrs	Constant each year

Graphical comparison of **Annual Transmission Charges (ATC)** under the **Building Block Method** and the **Annuity Method**



D. Pros & Cons

Building Block

- ✅ Transparent (clearly shows RoE, Interest, Depreciation
- ✅ Aligns with regulatory norms (CERC, etc.)
- ❌ Charges are **front-loaded**, may burden early users
- ❌ Yearly variation complicates long-term PPA/TSA planning

Annuity Method

- ✅ **Stable tariff** across asset life → attractive for beneficiaries
- ✅ Easier financial modelling (predictable cash flows)
- ❌ Less transparent: RoE is implicit in WACC
- ❌ Sensitive to assumed WACC → misestimation can over/under-reward investors

E. International Practices

- **India (CERC, SERCs):** Building Block approach
- **Europe (ENTSO-E studies):** Often use levelized cost (Annuity) for cost-benefit analysis
- **PPP/BOOT projects (global):** Annuity-based charges for uniform cash flow

F. Conclusion

- **Building Block method** is suitable in regulated environments where transparency and detailed cost segregation are essential.
- **Annuity method** is more suitable where predictability, simplicity, and financial structuring matter more than explicit cost tracking.

For **dedicated transmission lines** (DTLs), the choice depends on contractual arrangements:

- **Regulator-driven shared assets → Building Block**
- **PPP/Private negotiated assets → Annuity**

4. Mechanism for Sharing of Cost of Dedicated Transmission Line

A. Principles of Cost Sharing

- **Equity** — costs proportional to benefits.
- **Transparency** — clear calculation methodology.
- **Predictability** — stable and long-term.
- **Non-discrimination** — same rules for all users.
- **Cost causation principle** — "who causes the cost pays."

B. Objectives of Cost Sharing

- Ensure equitable distribution of costs among beneficiaries.
- Encourage optimal utilisation of transmission assets.
- Promote transparency and predictability in tariff determination.
- Support regional power market development

C. Methods for Sharing Transmission Charges of Dedicated Electrical Transmission lines

i) Contracted Capacity (MW) share

- **Mechanism:** Allocate ATC proportionally to each user's contracted capacity (MW). This is similar to take or pay in PPA.
- **Pros:** Simple, predictable, aligns with capacity reservation.
- **Cons:** Does not reflect actual utilization (energy throughput) nor distance.

ii) Proportional to the Energy Transmitted by the users: Energy (MWh) basis

- **Mechanism:** Allocate based on actual energy (MWh) consumed/carried through the DTL over a settlement period. This is like take and pay method used in PPA.
- **Pros:** Reflects usage and variable contribution to line loading.
- **Cons:** Variable charges; poor for fixed-capacity financing where financiers need stable revenue.

iii) MW-Mile (distance × capacity) Approach

- **Mechanism:** Capital and some operating costs allocated by product of MW and line length attributable to each user (captures distance-related cost).
- **Pros:** Penalizes remote connection; approximates network cost causation for linear lines.
- **Cons:** Requires agreed rules for apportioning segments when multiple users join/leave.

iv) **Hybrid Split Method:** Total Transmission charges are split into two components, let us say, 50:50. 50% of the transmission charges are paid based on contracted capacity and the remaining 50% are paid based on energy transmitted by each user. For an user, there will be two components of transmission charges- fixed cost based on capacity contracted and variable charge based on energy transmitted.

v) **Game-Theoretic (Shapley Value on Line Length):** Allocate cost by average marginal contribution of each user to the required line length across all joining orders.

1. Introduction

Cost allocation for Dedicated Transmission Lines (DTLs) is often contentious because different users are located at varying distances and require different contracted capacities. A fair allocation mechanism should reflect each user's true contribution to the cost of the line.

The Shapley Value, derived from cooperative game theory, is a widely recognised method that ensures equitable and transparent sharing of costs among participants.

2. Concept of Shapley Value

- Proposed by Lloyd Shapley (1953), the Shapley Value assigns a fair share of the total cost (or benefit) of cooperation among multiple players.
- It is based on the principle of average marginal contribution: how much extra cost each user brings when they join any possible coalition of users.
- In the context of DTLs, each user = player, and the cost of a coalition corresponds to the cost of building/operating a line that can serve all users in that coalition.

3. Why Shapley for DTLs

- Fairness: Accounts for both *capacity (MW)* and *location (distance)*.
- Non-discrimination: Every user's burden is proportional to the additional cost they impose.
- Stability: Users have no incentive to form sub-coalitions because the allocation is balanced.
- Transparency: Explicit formula based on all permutations of user entry.

4. Methodology

1. Define the cost function for any coalition of users (e.g., based on farthest distance × total capacity, or segmented MW-km cost).
2. Compute marginal contributions: For each ordering of users, calculate how much extra cost is incurred when a user joins.
3. Average across all permutations: Each user's Shapley Value is the mean of their marginal contributions.
4. Allocate the total ATC (Annual Transmission Charge): The sum of Shapley Values equals the total project cost, ensuring no deficit or surplus.

6. Advantages and Limitations

<u>Advantages</u>

- Equitable: considers both location and size.
- Flexible: adaptable to different cost functions (MW-Km, segmental, etc.).
- Transparent: derivation is systematic and reproducible.

<u>Limitations</u>

- Computationally intensive for large numbers of users (though formulaic shortcuts exist).
- May be conceptually complex for stakeholders unfamiliar with game theory.

<u>D. WORKED OUT EXAMPLE</u>

Consider the following single base scenario

Annual Transmission Charges (ATC): NPR 90,000,000 per year

- Contracted Capacity: Users: A -100 MW, User-B -150 MW, User-C -50 MW

  Total 300 MW

- Tap distances from the source (km): A=60, B=120, C=200
- Capacity factors (CF): A=0.80, B=0.50, C=0.30 → annual MWh differ across users

i) <u>Proportional to Contracted Capacity (MW)</u>

<u>Logic:</u> Allocate in proportion to each user's contracted MW.

- Total MW = 300
- Shares: A 100/300=33.33%, B 150/300=50.00%, C 50/300=16.67%
- Annual costs:
  - A: NPR 30.00 M
  - B: NPR 45.00 M
  - C: NPR 15.00 M

<u>When to use</u>: Simple, stable commitments; good when the asset is sized by contracted MW.

ii) <u>Energy-Based (MWh)</u>

<u>Logic</u>: Allocate by actual energy (MWh) delivered/evacuated over the year.

- Annual MWh (8760 h):
  - A: 100×0.80×8760 = 700,800
  - B: 150×0.50×8760 = 657,000
  - C: 50×0.30×8760 = 131,400
  - Total = 1,489,200 MWh
- Shares: A 47.07%, B 44.12%, C 8.82%
- Annual costs:
  - A: NPR 42.36 M
  - B: NPR 39.71 M
  - C: NPR 7.93 M

<u>When to use:</u> Rewards higher utilization; suitable where metering is robust, and usage varies.

iii) Distance-Weighted (MW-Km or MW-Mile)

Logic: Heavier users and longer use of the line pay more. Allocate by MW × Km to the tap.

- MW · Km:
  - A: 100×60 = 6,000
  - B: 150×120 = 18,000
  - C: 50×200 = 10,000
  - Total = 34,000
- Shares: A 17.65%, B 52.94%, C 29.41%
- Annual costs:
  - A: NPR15.88 M
  - B: NPR47.65 M
  - C: NPR26.47 M

When to use: Taps at different distances; reflects network usage intensity.

iv) Hybrid Split (e.g., 60% by MW + 40% by MWh)

Logic: Blend fixed capacity commitment with variable usage.

- Fixed 60% by MW (as in method #1), variable 40% by MWh (as in #2)
- Annual costs:
  - A: NPR35.18 M
  - B: NPR42.43 M
  - C: NPR12.39 M

When to use: Balanced incentives; common in long-term PPAs and shared lines.

vi) Game-Theoretic (Shapley Value on Line Length)

Example

Input data:

- A: 100 MW, 60 km
- B: 150 MW, 120 km
- C: 50 MW, 200 km

- **Logic:** Allocate cost by average marginal contribution of each user to the required line length across all joining orders (assuming uniform cost per km and a single radial with taps at 60, 120, 200 km).

Step 1 — find unit rate u

Full-coalition farthest distance = 200 km.
Full-coalition total capacity = 100 + 150 + 50 = 300 MW.

Set:

u×200×300=90,000,000⇒u=90,000,000200×300]

=NPR1,500 per MW-km (annual)

Step 2 — cost function values for all coalitions

- cost({A}) = 1,500 × 60 × 100 = NPR9,000,000
- cost({B}) = 1,500 × 120 × 150 = NPR27,000,000
- cost({C}) = 1,500 × 200 × 50 = NPR15,000,000
- cost({A,B}) = 1,500 × 120 × (100+150=250) = 1,500×120×250 = NPR45,000,000
- cost({A,C}) = 1,500 × 200 × (100+50=150) = 1,500×200×150 = NPR45,000,000
- cost({B,C}) = 1,500 × 200 × (150+50=200) = 1,500×200×200 = NPR60,000,000
- cost({A,B,C}) = 1,500 × 200 × 300 = NPR90,000,000 (matches ATC)

Step:3

1) Permutation: A → B → C

- A's marginal = cost({A}) − cost(∅) = 9,000,000
- B's marginal = cost({A,B}) − cost({A}) = 45,000,000 − 9,000,000 = 36,000,000
- C's marginal = cost({A,B,C}) − cost({A,B}) = 90,000,000 − 45,000,000 = 45,000,000

2) Permutation: A → C → B

- A: 9,000,000
- C: cost({A,C}) − cost({A}) = 45,000,000 − 9,000,000 = 36,000,000
- B: cost({A,B,C}) − cost({A,C}) = 90,000,000 − 45,000,000 = 45,000,000

3) Permutation: B → A → C

- B: 27,000,000
- A: cost({A,B}) − cost({B}) = 45,000,000 − 27,000,000 = 18,000,000
- C: cost({A,B,C}) − cost({A,B}) = 90,000,000 − 45,000,000 = 45,000,000

4) Permutation: B → C → A

- B: 27,000,000
- C: cost({B,C}) − cost({B}) = 60,000,000 − 27,000,000 = 33,000,000
- A: cost({A,B,C}) − cost({B,C}) = 90,000,000 − 60,000,000 = 30,000,000

5) Permutation: C → A → B

- C: 15,000,000
- A: cost({A,C}) − cost({C}) = 45,000,000 − 15,000,000 = 30,000,000
- B: cost({A,B,C}) − cost({A,C}) = 90,000,000 − 45,000,000 = 45,000,000

6) Permutation: C → B → A

- C: 15,000,000
- B: cost({B,C}) − cost({C}) = 60,000,000 − 15,000,000 = 45,000,000
- A: cost({A,B,C}) − cost({B,C}) = 90,000,000 − 60,000,000 = 30,000,000

Step:4

Sum the marginals for each player (over all 6 permutations)

A's marginals:
9,000,000 + 9,000,000 + 18,000,000 + 30,000,000 + 30,000,000 + 30,000,000
= 126,000,000

B's marginals:
36,000,000 + 45,000,000 + 27,000,000 + 27,000,000 + 45,000,000 + 45,000,000
= 225,000,000

C's marginals:
45,000,000 + 36,000,000 + 45,000,000 + 33,000,000 + 15,000,000 + 15,000,000
= 189,000,000

Average (divide each sum by 6 permutations)

- A: 126,000,000 ÷ 6 = **NPR21,000,000**
- B: 225,000,000 ÷ 6 = **NPR37,500,000**
- C: 189,000,000 ÷ 6 = **NPR31,500,000**

When to use: Negotiations where fairness to incremental build requirement matters; reflects that the farthest user drives most of the line length.

C. Interpretations of the numbers computed above

User	Contracted Capacity	Energy Based	MW-Mile or MW-Km	Hybrid	Game-Theoretic
User-A	30 M	42.36 M	15.88 M	36.18 M	21 M
User-B	45 M	39.71 M	47.65 M	42.35 M	37 M
User-C	15 M	7.93 M	26.47 M	11.47 M	21 M
Total	90 M	90 M	90 M	90 M	90 M

- **Capacity-only (MW)** favours contractual firmness;
- **Energy-only (MWh)** favours efficient, high-CF users and penalizes low-use capacity holders.
- **MW-Km** charges distant taps more; Shapley makes the farthest user bear most of the cost when line length is the binding driver.
- **Hybrids** offer a pragmatic middle ground, mitigating extremes and smoothing volatility.

D. Best Practices adopted in various countries

India

- **Electricity Act, 2003:** DTLs are typically owned by generating companies or dedicated licensees.
- **CEA Guidelines:** Beneficiaries bear costs in proportion to contracted capacity.
- **CERC Regulations:** Provide clarity on cost allocation when DTL is used by multiple generators.

SAARC Countries

- **Pakistan, Bangladesh, Bhutan, Sri Lanka**: Similar approach — "first user pays," with later users compensating proportionally.
- **Regional Grid Projects**: Cost-sharing often determined through bilateral/multilateral agreements.

Developed Countries

- **USA (FERC):** Participant Funding — developers pay for lines, but cost is refunded proportionally if new users join.

- **EU (ENTSO-E):** Costs allocated via benefit-based methodology, considering system reinforcement benefits.

E. Conclusion

Selecting the right cost sharing methodology depends on:

- Predictability of usage
- Nature of beneficiaries
- Metering and contractual framework
- Regulatory requirements

A hybrid model combining contracted capacity and actual usage often provides the fairest results.

5. Mechanism for Sharing of Grid Reinforcement Cost

A. Extent of Cost Sharing of the Dedicated Transmission Line by the Users

The Core Idea

When a new generator, consumer, or entity wants to connect to the grid, a dedicated transmission line (DTL) is often needed. In cost-sharing terms, this is almost always that the 100% of the cost of the dedicated transmission line is borne by the users. The question of bearing the additional network reinforcement cost arises. This gives rise to the concept of Shallow Charging, Deep Charging and Hybrid Charging Concepts.

Three common approaches:

I. Shallow Charging

- Definition:

  The connecting party pays only for the assets directly needed to connect their facility to the nearest point on the existing network.
- This means:
  - User pay for the dedicated line from its plant/substation to the nearest grid substation.
  - User do not pay for any upstream network reinforcements (like extra transformers, lines, or grid strengthening far away).
- Example:

A wind farm 30 km away from a 220 kV substation:

  - Under shallow charging: it will pay for the 30 km dedicated line and the bay at the substation.
  - If the utility needs to upgrade a distant 400 kV line to handle extra load, that's paid by the transmission licensee and recovered from all users i.e. it is socialised.
- Pros:
  - Lower and more predictable upfront cost for the connecting party.
  - Encourages new connections (supports renewable energy projects).

- Cons:
  - Other network users end up paying for upstream reinforcements, even though they don't directly benefit.
  - May encourage inefficient location choices (developers don't consider full system costs).
- **Illustrative Example (Shallow Charging):**

Shallow Charging			
Asset Component	Total Cost	Cost to be paid by Connecting Entity	Cost to be socialised
DTL upto nearest Sub-station	8	8	0
Sub-Station Bays	2	2	0
Grid Strengthening	10	0	10
Total	20	10	10

II. Deep Charging

- Definition:

  The connecting party pays for all network upgrades necessary to accommodate their connection — including remote reinforcements anywhere in the network.
- This means:
  - Users pay for the dedicated line plus any upgrades the transmission licensee must do in the wider grid.
- Example:

  Using the same wind farm:
  - User pay for the 30 km line + substation bay + cost of strengthening the 400 kV line 200 km away if it's needed due to your generation.
- Pros:
  - Sends a strong location signal — developers think about total system cost.
  - Reduces cross-subsidy from existing customers.
- Cons:
  - High and unpredictable upfront cost — can discourage projects.
  - Cost allocation can be complex, especially if multiple projects cause the need for reinforcements.
- Illustrative Example (Deep Charging):

Deep Charging			
Asset Component	Total Cost	Cost to be paid by Connecting Entity	Cost to be socialised
DTL upto nearest Sub-station	8	8	0
Sub-Station Bays	2	2	0
Grid Strengthening	10	10	0
Total	20	20	0

III. Hybrid Charging Model

Some countries use a "shallow-ish" or "hybrid" charging model:

- The connecting party pays for the DTL and some local reinforcements (within a certain radius or voltage level).
- Distant reinforcements are socialized (paid from general network tariffs).

Illustrative Example (Hybrid Charging):

Hybrid Charging			
Asset Component	Total Cost	Cost to be paid by Connecting Entity	Cost to be socialised
DTL upto nearest Sub-station	8	8	0
Sub-Station Bays	2	2	0
Grid Strengthening (40% by user)	10	4	6
Total	20	14	6

B. **Comparative Table**

Aspect	**Shallow Charging**	**Swallowing Charging**
Cost scope	Direct connection only	Connection + all triggered reinforcements
Upfront cost	Lower	Higher
Network upgrade cost	Socialized	Borne by entrant
Impact on investment	Encourages new connections	Encourages optimal siting

C. International Practices

Country/Region	Approach	Notes
India	Mostly Shallow for ISTS; DTL cost borne by user	In CTU (ISTS) framework, generators pay for dedicated lines; system strengthening costs are pooled.
UK	Modified shallow	Local connection paid by user; deeper reinforcements partly charged under "user commitment."
USA (FERC)	Often Deep in some RTOs; hybrid in others	E.g., PJM assigns costs of upgrades to triggering parties.
Australia	Shallow for connections; deep for certain augmentations	Rules under NER.

6. Financial Settlement for Users' Arrival and Departure Pattern (Late Entrant, Early Exit, No-Show) and Contracted Capacity Enhancement

A. A Dedicated Transmission Line (DTL) is typically built to serve one or more identified users (e.g., generators, bulk consumers, distribution utilities). The cost recovery mechanism becomes complex when:

- All identified users do not join at the time of commissioning,
- Some users leave after a few years,
- Some users enhance their contracted capacity, and
- New users join at later stages.

To ensure fair and efficient recovery of costs, regulators and utilities adopt specific principles and methodologies.

B. Key Principles of Cost Recovery

1. Cost Reflectivity: Users should bear costs in proportion to their usage or contracted capacity.
2. Equity & Non-Discrimination: No user should be unfairly burdened due to early or late entry.
3. Revenue Adequacy: The Transmission Licensee must be able to recover the approved Annual Transmission Charges (ATC).
4. Flexibility: The mechanism should accommodate entry, exit, and capacity enhancement.
5. Stability & Predictability: Users should know upfront how their liabilities may change with system changes.

C. Approaches to Cost Recovery

(a) Initial Allocation at COD (Commercial Operation Date)

- Capital cost apportioned among identified users based on contracted capacity (MW ratio).
- ATC recovered annually from each user on pro-rata basis.

(b) Late Entrants (Users Joining Later)

Here Buy-In Approach is generally used.

Buy-in Approach in Cost Sharing

The **Buy-in Approach** is a cost allocation mechanism applied when a **new user (late entrant)** joins an existing dedicated transmission line (DTL) or shared infrastructure that was originally funded by initial users.

Key Features:

1. **Compensation to Existing Users**:
   - The late entrant pays a **buy-in charge** to the existing users who already invested in and bore the costs of the asset.
   - This ensures fairness by avoiding "free-riding" on sunk costs.
2. **Basis of Buy-in Charge**:
   - Generally calculated as the **present value of the share of costs** that the late entrant would have paid if it had joined from the beginning.
   - Can include:
     - Capital cost recovery (depreciated value of assets).
     - Financing cost (interest, return on equity).
     - O&M cost sharing from the joining date onwards.
3. **Settlement**:
   - The buy-in charge is distributed among existing users, reducing their burden going forward.
   - The late entrant thereafter pays its share of **Annual Transmission Charges (ATC)** prospectively.

Advantages:

- Ensures fairness between early investors and late entrants.
- Encourages wider participation in shared transmission projects.
- Prevents disputes over "stranded" costs.

Limitations:

- Requires robust methodology for asset valuation and depreciation.
- May discourage new users if buy-in charges are very high.

EXAMPLE

Input Data

- **ATC:** NPR 40.00 crore/year (levelized)
- **Tenure:** 25 years
- **Allowed WACC (discount rate):** 10%
- **Initial users & contracted MW (and shares):**
    - A: 50 MW (50%)
    - B: 30 MW (30%)
    - C: 20 MW (20%)
- **Payments in Years 1–5:**
- A NPR 20, (crore per year)
- B NPR 12, (crore per year)
- C NPR 8 (crore per year)
- **Late entrant D** joins **at the start of Year 6** with **25 MW**.
- Total becomes **125 MW**.

Annuity Factor (20,10%) = 8.5136

Step 1 — Compute past recovery to the join date (for buy-in)

PV of the Past ATC collected in Years 1–5, **accumulated** to the start of Year 6 at 10%: = 40×(1.10)^4+40×(1.10)^3+40×(1.10)^2+40×(1.10)^1+40=NPR 244.204 crore

Step 2 — Decide the buy-in (entry fee) rule based on **"past contribution" buy-in**

Late entrant pays their **post-join share** of the **compounded past recovery**; this is distributed to the legacy users in proportion to what they actually paid.

- Post-join shares (with 125 MW total):
  A 40%, B 24%, C 16%, D 20%
- **D's entry fee (buy-in): 20%×NPR 244.204=NPR 48.8408**

Distribute this to legacy users in their historic proportions (A 50%, B 30%, C 20%):

- A receives NPR 24.4204 cr
- B receives NPR 14.6522 cr
- C receives NPR 9.7682 cr

Step 3 — Ongoing charges from Year 6 onward

With 125 MW total, the **annual split of the NPR 40 cr ATC** becomes:

- A: 40%×40= **NPR 16.00 cr/yr**

- B: 24%×40= **NPR 9.60 cr/yr**
- C: 16%×40= **NPR 6.40 cr/yr**
- D: 20%×40= **NPR 8.00 cr/yr**

(c) Exit of Users

Here **Make-Whole** approach is normally adopted.

The **Make-Whole Approach** is a settlement mechanism used in dedicated transmission lines (DTLs) when a **user exits early**. The principle is to ensure that the **remaining users are not burdened** with higher transmission charges because of the exit of user(s).

Key Features:

1. **Protection of Remaining Users**:
   - The exiting or defaulting user pays compensation (make-whole payment) so that the **original revenue requirement of the transmission line remains intact**.
   - This way, the transmission service provider continues to recover the full **Annual Transmission Charges (ATC)**.
2. **Computation**:
   - The make-whole payment is generally calculated as the **net present value of the share of ATC** the user would have paid for the remaining contract period.
   - This ensures that no additional burden shifts to other users.
3. **Settlement**:
   - The payment made by the exiting party is directly adjusted against the total revenue requirement of the asset owner.

Advantages:

- Prevents cost-shifting and protects long-term users.
- Provides certainty of revenue recovery for the transmission developer.
- Encourages contractual discipline among users.

Limitations:

- Exiting users may face **large financial liabilities**, which can discourage flexibility.
- Requires robust contracts and enforcement mechanisms.

EXAMPLE

ATC: NPR 40 crore/year

Tenure: 25 years **Discount rate :** 10%

Users & initial contracted shares: A: 50% , B: 30% , C: 20%,

Annual payments at start: A: NPR 20 cr, B: NPR 12 cr, C: NPR 8 cr

Annuity Factor (20,10%) = 8.5136

Case A: B exits at end of Year 5

Option A1: Make-whole / termination charge (preferred)

B's remaining obligation stream: **NPR 12 cr/yr for 20 years**

Termination charge at exit (PV at end of Year 5): 12 X8.5136 =102.16 crore

B can alternatively bring a replacement to take over the same stream (then B's termination charge is reduced by what the replacement commits to pay).

Option A2: Redistribution to remaining users (A & C)

Remaining shares re-normalized to

A = 50/70X100=71.4286% C= 20/70X100=28.5714%

New annual charges from Year 6:

A= 71.4286%×40= **NPR 28.5714 cr** (was NPR 20; **+NPR 8.5714**)

C: 28.5714%×40=28.5714= **NPR 11.4286 cr** (was NPR 8; **+NPR 3.4286**)

PV at end of Year 5 of these **extra** burdens:

A: 8.5714×8.5136=8.5714 \times 8.5136 =8.5714×8.5136= **NPR 72.97 cr**

C: 3.4286×8.5136=3.4286 \times 8.5136 =3.4286×8.5136= **NPR 29.19 cr**

Total = NPR 102.16 cr = B's termination PV (the books balance).

Case B — All users (A, B, C) exit together at end of Year 5

Unrecovered obligation stream on the asset: **NPR 40 cr/yr for 20 years**

Total termination PV at end of Year 5=NPR 340.54 crore

Under a **make-whole** rule, this must be settled at exit in proportion to contracted shares:

A (50%): **NPR 170.27 cr**

B (30%): **NPR 102.16 cr**

C (20%): **NPR 68.11 cr**

If there's **no make-whole** clause and **no new beneficiaries** picked up, the developer is left with **NPR 340.54 cr of stranded PV**—which is precisely why "everyone exits and pays nothing" is **not** a viable or typical arrangement for a dedicated asset.

(d) No-Show (Non-Participation of Identified Users)

The identified user do not join.

Settlement Mechanisms

1. **Take-or-Pay Principle**
    1. User pays full transmission charges for their contracted capacity, whether or not they use it.
    2. Protects existing users and the transmission licensee from stranded cost.
    3. Standard in many Power Purchase Agreements (PPAs) and Transmission Service Agreements (TSAs).
2. **Penalty Mechanism**
    1. Additional penalty imposed for consistent non-utilization (to discourage speculative booking).
    2. Could be a surcharge on top of contracted charges.
3. **Capacity Resale / Reallocation**
    1. Unused contracted capacity can be reallocated to new/other users (via regulatory or market mechanism).
    2. Original "no-show" user still pays until replaced but may recover part through resale.
4. **Force Majeure Exception**

    If no-show is due to force majeure (uncontrollable events), settlement terms may be relaxed by the regulator

    If identified users do not join due to force majeure exception, the burden may be:

    - Shared among the participating users (causing tariff increase), or
    - Passed through to the concerned generator/distribution licensee as per regulatory decision.
    - Regulators may impose default contribution clauses to safeguard transmission licensee's recovery.

Settlement Mechanisms for "No Show"

1. **Take-or-Pay Principle**
   - User pays full transmission charges for their contracted capacity, whether or not they use it.
   - Protects existing users and the transmission licensee from stranded cost.
   - Standard in many Power Purchase Agreements (PPAs) and Transmission Service Agreements (TSAs).
2. **Penalty Mechanism**
   - Additional penalty imposed for consistent non-utilization (to discourage speculative booking).
   - Could be a surcharge on top of contracted charges.
3. **Capacity Resale / Reallocation**
   - Unused contracted capacity can be reallocated to new/other users (via regulatory or market mechanism).
   - Original "no-show" user still pays until replaced, but may recover part through resale.
4. **Force Majeure Exception**
   - If no-show is due to force majeure (uncontrollable events), settlement terms may be relaxed.

(e) Enhancement of Contracted Capacity

- User's share is recomputed based on revised MW allocation.
- Additional burden borne by enhanced user reduces charges for others.

D. Regulatory Best Practice

- **Financial Commitment at Entry:** Require bank guarantees or advance payment to avoid risk of no-show.
- **Clear Clauses in TSA:** Explicit provisions on liability, penalties, and treatment of no-shows.
- **Make-Whole for Existing Users:** Ensure that cost burden is not shifted to others unfairly.
- **Buy-In Approach** for late entrants

E. International Regulatory Practices

- India (CERC): Pro-rata sharing, late payment surcharge for late entrants, exit liability clauses in TSA.
- Europe (ENTSO-E): Shallow connection charges, with make-whole arrangements for exiting parties.
- USA (FERC): Transmission service agreements ensure long-term take-or-pay commitments.

F. <u>Challenges</u>

- Disputes over treatment of late entrants and exits.
- Revenue risk for transmission licensee.
- Equity concerns when some identified users never join.
- Complexity in recalculating shares periodically.

G. <u>Conclusion</u>

Recovery of capital cost in a dedicated transmission line with dynamic participation requires a robust regulatory framework that ensures:

- Full recovery of capital cost,
- Fair sharing among users,
- Protection against free-riding and early-exit risks.

Mechanisms like annuity-based recovery, make-whole clauses, buy-in for late entrants etc. are widely used to balance equity and financial stability.

7. Methodology for Sharing of Loss

DTLs are built to serve identified users. Apart from transmission charges, line losses must also be allocated. Loss sharing methodology should be such that it i9s simple, transparent and at the same time ensures fairness among users.

Types of Losses

- **Technical Losses**
    - I^2R losses (conductor resistance)
    - Transformer/core losses
    - Depend on distance, load, and line parameters.
- **Commercial Losses**
    - Metering, accounting errors (minimal in DTLs).
    -

Loss Sharing Principles

- **Causation Principle:** Loss are borne by those causing it.
- **Equity Principle:** Loss apportioned fairly among all users.
- **Transparency & Simplicity:** Easily verifiable methodology.
- **Consistency:** Same approach for all users and over time

Methods to compute losses on DTLs

- **Deterministic (engineering) method:** Calculate expected losses using powerf low models (load flow simulations) or analytic I^2R formulae using forecasted load/dispatch patterns. Good for ex-ante tariff design.
- **Metering/settlement method:** Measure energy injected and energy received at endpoints; compute net loss as difference and allocate historically (ex-post). Useful where high-accuracy metering exists.

Methods for Loss Sharing

1. **Pro-rata based on Contracted Capacity (Method-1)**
    - Loss is distributed among the users in ratio of user's contracted MW share.

- It is simple and predictable.
- Because of varying CUFs of the users, it may not reflect the actual loss caused by each user.

2. **Pro-rata based on Actual Usage (Energy Injected/Drawn) (Method-2)**
    - Loss is shared among the users in proportion of the power injected.
    - It is more accurate but needs metering at injection and drawl points
3. **MW-Km Method (Hybrid-1)**
    - Loss is shared in proportion to (Capacity × Distance).
    - Reflects physics: longer use causes more loss.
4. **MWHr-Km Method (Hybrid-2)**

    It is more accurate than the MW-Km approach. Here instead of the contracted capacity, the loss is apportioned based on energy injected in a given period along with the distance. It intrinsically takes Capacity Utilisation factor into account. As such, it is a better estimate than the MW-Km Method.
5. **Marginal Loss Method**
    - Allocates incremental loss contribution of each user.
    - Most accurate, but complex.

Example

Input Data

Contract Capacity of Users: Users: A (60 MW), User-B (40 MW)

A is 100 km away, B is 50 km away from the interface

Energy Injected during the month: User-A: 34560 MWHr, User-B: 14400 MWHr

Total Technical Loss in a particular month = 10 MWHr

- **Method 1 (Contracted Capacity):**
    - Loss Attributed to User-A 6 MWHr
    - Loss Attributed to User-B 4 MWHr
- Method 2 (MWHr Approach)
    - Loss Attributed to User-A 7 MWHr
    - Loss Attributed to User-B 3 MWHr

- **<u>Method 3 (MW-Km Method</u>)(Hybrid-1)**
    - Loss Attributed to User-A 7.5 MWHr
    - Loss Attributed to User-B 2.5 MWHr
- **Method 4 (MWHr-Km) Method (Hybrid-2)**
    - Loss Attributed to User-A 8.3 MWHr
    - Loss Attributed to User-B 1.7 MWHr

See how the loss attributed to User-B is getting decreased with increased refinement.

<u>Conclusion</u>

- Loss sharing is a critical part of DTL cost allocation.
- Choice of method depends on:
    - Number of users, distance, and complexity.
    - Regulatory framework.

- For an untapped DTL line, MWHr Approach is reasonable.
- For a tapped DTL line. **MWHr-Km approach** often ensures fairness and practicality.

8. Challenges & Issues

Challenges & Issues in Dedicated Transmission Lines

A. Disputes over Cost Allocation

- **Problem:**
  - Multiple users on a DTL may contest how capital cost, O&M, and losses are apportioned.
  - Single "anchor" users often argue against subsidizing later entrants (free-rider problem).
- **Examples:**
  - In India, disputes before CERC on whether new generators using an existing DTL should pay "use-of-system" charges to the anchor owner.
  - In EU CBCA projects, difficulty agreeing on "beneficiary shares" among member states.
- **Best Practice Mitigation:**
  - Standard allocation methods (MW-km, capacity share).
  - Regulator-approved model Transmission Service Agreements (TSAs).
  - True-up mechanisms + independent audits.

B. Impact of Changing System Configuration

- **Problem:**
  - DTLs may start as point-to-point, but later get integrated into the grid (becoming "common carrier").
  - New taps, extensions, or mergers change the flow pattern and the beneficiaries.
- **Challenges created:**
  - Original cost allocation may no longer be fair.
  - Anchor investor may seek protection against "stranded cost".
  - Operationally, a radial DTL integrated into the meshed grid requires new protection/coordination.
- **Examples:**
  - Merchant lines in the US (under FERC Order 1000) later absorbed into ISO's transmission plan.

- India: private DTLs reclassified as ISTS assets.

- **Best Practice Mitigation:**
    - Conversion clauses in TSA: specify how costs are re-allocated if line becomes part of the grid.
    - Regulatory approval of buy-out mechanisms or asset transfer at RAB value.

C. Regulatory Uncertainty

- **Problem:**
    - Ambiguity in treatment of DTLs — are they purely private or subject to regulated tariff norms?
    - Cross-border projects face uncertainty in taxation, RoW compensation, and cost recovery.
- **Challenges created:**
    - Risk perception rises → financing costs increase.
    - Developers hesitate to invest without clear policy.
- **Examples:**
    - India's evolving rules on treatment of dedicated lines (who bears cost, whether PoC applies).
    - South Asia cross-border DTLs (India–Nepal, India–Bangladesh) often slowed by unclear benefit-sharing frameworks.
- **Best Practice Mitigation:**
    - Stable regulatory guidelines (clear definition of DTL, shallow charging principle).
    - Harmonization in cross-border agreements (SAARC framework, ENTSO-E CBCA).
    - Long-term TSA backed by regulatory approval to anchor financing.

D. Technical Complexities in Loss Measurement

- **Problem:**
    - Losses in DTLs vary with load, conductor temperature, and taps.
    - Allocating segment losses to users (especially in multi-tap lines) is computationally intensive.
- **Challenges created:**
    - Disputes over "fairness" in allocation.

- Requires accurate metering and reliable load data.

- **<u>Examples:</u>**
  - EU cross-border trade disputes over settlement of losses at interconnectors.
  - Indian DTL cases where anchor users claim higher-than-actual losses being billed.

- **<u>Best Practice Mitigation:</u>**
  - Use seasonal fixed loss factors for simplicity, with option of hourly true-up for large/multi-user lines.
  - Standardize metering (GPS-synchronized, bidirectional).
  - Independent verification of loss studies by regulator or third-party

9. Role of the Regulatory Commission in Dedicated Transmission Lines (DTLs)

A. Core Guiding Principles for Regulatory Commission

- **Fair, transparent, and efficient** development and use of DTLs.
- **Investor certainty**, **user equity**, and **system reliability**.
- Alignment of DTLs with **national transmission planning** and **grid development priorities**.
- **Cost-causation & beneficiary-pays:** Parties who cause need or receive benefits from DTL fund the assets.
- **Shallow connection by default:** User pays dedicated assets; wider grid reinforcements are socialized via the mainstream tariff (unless a negotiated "deep" case is justified).
- **Predictability:** Simple, transparent formulas with periodic true-ups beat opaque models.
- **Modularization:** Unbundle line segments/bays/telecom/SCADA; charge only what's used.
- **Pro-competition & non-discrimination:** Same rules for incumbents and entrants.
- **Ex-ante clarity + ex-post true-up:** Lock the method up front; reconcile to actuals.

B. Roles of ERC

1. Approval of Need and Prudence Check

- Examine whether the DTL is genuinely "dedicated" (i.e., constructed exclusively for identified beneficiaries, not a common carrier).
- Approve the capital cost, financing structure, and technical configuration.
- Ensure the project is not oversized or underutilized, and that it complies with grid standards.

2. Tariff Determination & Cost Recovery Framework

- Approve methodology for recovery of **Annual Transmission Charges (ATC)**:
  - Return on equity, depreciation, interest on loan, O&M, taxes.
  - Choose the tariff design: annuity or building block

- **Frame cost-sharing principles:**
    - Initial allocation among identified beneficiaries (MW share, usage, distance, etc.).
    - Rules for **late entrants**, **early exits**, **capacity augmentation**, and **no-shows**.
- Ensure that charges are **just, reasonable, and non-discriminatory**.

3. Dispute Resolution & Contract Enforcement

- Act as an arbitrator if disputes arise among DTL users (e.g., over entry fee, exit liability, augmentation costs).
- Enforce the contractual obligations — especially in cases of early exit, stranded cost, or refusal to pay.

4. Safeguard against Stranded Costs

- Define "make-whole" arrangements: exiting users must either continue to pay their share, bring replacements, or pay termination charges.
- Ensure late entrants compensate legacy users through Buy-In method.
- Decide who bears stranded cost if users default or withdraw — the DTL owner should not be left exposed.

5. Regulatory Oversight & Monitoring

- Monitor performance, reliability, and compliance with Grid Code & safety standards.
- Approve changes in ownership, augmentation, or additional users.
- Oversee settlement of losses (technical & commercial) and billing systems.

6. Integration with National/Regional Transmission Policy

- Decide whether and when a DTL should be **converted into a regional/national asset** if multiple parties eventually benefit.
- Align DTL tariff principles with the broader transmission pricing framework (pooled vs. dedicated).
- Provide clarity on **deep vs. shallow connection charges**

7. Transparency & Fairness

- Ensure all users have visibility of cost structure, billing, and adjustment mechanisms.

Approve information disclosure formats for DTL developers/operators.

8. **<u>Policy & Best Practice Alignment</u>**

- **Incorporation of International Best Practices** → Apply lessons from FERC (USA), Ofgem (UK), CERC (India), and others.
- **Encouraging Efficient Investment** → Promote shallow charging where appropriate, discourage gold-plating, and support renewable evacuation through dedicated lines.
- **Future-readiness** → Ensure adaptability for open access, competition, and integration of cross-border power flows.

C. ERC's Role vis-à-vis Categorization of DTL Projects

(a) Already Constructed & Operational DTLs

- **Tariff Review & Approval** → Approve Annual Transmission Charge (ATC) using Building Block or Annuity Method for the categories of DTL built by Developers (not the IPPs themselves).
- **Cost Verification** → Conduct **prudence check** of actual capital expenditure. Disallow excess/inefficient costs.
- **Performance Monitoring** → Mandate reporting on O&M, losses, reliability indices.
- **Re-optimization** → Allow revaluation/repurposing if line is under-utilized, ensuring stranded cost recovery

(b) DTL Under Construction

- **Pre-Construction Approval** → Review Detailed Project Report (DPR), financing plan, cost estimates.
- **Construction Monitoring** → Track progress, prevent delays/cost overruns, and publish quarterly compliance reports.
- **Interim Cost Recovery** → Allow provisional tariff (if project delayed) to protect cash flow, subject to true-up later.
- **User Participation** → Ensure beneficiaries are consulted in construction stage for transparency.

(c) Future / Proposed DTLs

- **System Planning Integration** → Approve DTLs consistent with National Transmission Master Plan.
- **Least-Cost Justification** → Verify technical alternatives (e.g., pooling station vs. dedicated line).
- **Cost Allocation Framework** → Define upfront sharing principle (contracted MW, MW-mile, energy-based, hybrid).
- **Entry/Exit Rules** → Approve framework for late entrant buy-in charges, early exit obligations, and expansion cost sharing.

- **Encouragement of Innovation** → Incentivize smart grid technologies, underground cables in urban zones, or cross-border facilitation.

10. Suggested Approach for Nepal on Important Issues on DTL

Sl. No.	Issue	Suggested Approach
1	**Computation Methodology for Annual Transmission Cost (ATC) for DTL**	• Building Block Method • Cross verification by Annuity Method
2	**Cost Sharing Mechanism for DTL**	• Untapped Line: Contracted Capacity Method • Tapped Line: MW-Mile or MW-Km Method
3	**User Behaviours**	
	Late Entrant	• New beneficiaries shall pay a **Buy-in Fee**
	Early Exit	• **Make-Whole** Arrangement
	No-Show	• **Take or Pay** provision in TSA
	Contracted Capacity Enhancement	• Share of each user is recomputed based on revised MW allocation.
4	**Deep vs. Shallow Connection Charging**	• **Shallow Connection Charging** • **Grid Reinforcement Cost to be socialised**
5	**Loss Calculation and Loss sharing principle**	• **MWHr approach** for untapped DTL • **MWHr-Mile** Approach for tapped DTL
6	**Stranded DTL Assets**	• ERC shall take decision on case to case basis

11. References

Regulatory Frameworks & International Guidelines

1. Central Electricity Regulatory Commission (India) — regulations & guidance on dedicated transmission lines and connectivity procedures. CERCCTU
2. Federal Energy Regulatory Commission (FERC) — Transmission Planning and Cost Allocation (Order No. 1000) and related materials. Federal Energy Regulatory Commission+1
3. EirGrid / ESB Networks — Charging and Rebate Principles; discussion on shallow vs deep charging. esbnetworksprdsastd01.blob.core.windows.net
4. Regulatory Assistance Project (RAP) — *Electric Cost Allocation for a New Era* (manual on cost allocation options and principles). Regulatory Assistance Project
5. World Bank / ESMAP and other cross-border transmission studies — planning and cost allocation for large transmission investments. ESMAPSarep Energy
6. **European Union – Cross-Border Cost Allocation Guidelines**

- Regulation (EC) No 714/2009: Establishes principles for access to the network for cross-border electricity exchanges, including cost-sharing principles. EUR-Lex
- Part of the EU Third Energy Package (~2009), which ushered in ownership unbundling and strengthened cross-border transmission access regulation.Wikipedia+1

7. **ENTSO-E (European Network of Transmission System Operators for Electricity)**

- Under EU mandates, ENTSO-E develops ten-year network development plans (TYNDP) and cost–benefit evaluation methodologies for major regional transmission infrastructure, which inform cost-sharing and project prioritization. Wikipedia

8. **United States – FERC Order 1920 / 1920-A**

- FERC Order 1920 (2024) directs utilities to plan 20+ years ahead for regional transmission needs, with a default cost-sharing plan to ensure fair cost distribution across states. Amendments in 1920-A enhance state participation in allocation processes. Wikipedia

9. **India – Regulatory & Tariff Policies**

- National Tariff Policy (2006, revised 2016): Sets the framework for cost-of-service regulation for transmission and promotes transparent pricing and private-sector participation. indiatransmission.org
- **Central Electricity Regulatory Commission (CERC) – Sharing of Inter-State Transmission Charges and Losses (2010, updated 2020):**

- Introduces the Point-of-Connection (PoC) mechanism for allocation of inter-state transmission costs. Indian Kanoon
- Clarifies treatment of dedicated transmission lines owned by generating stations and mandates standardized cost-per-circuit-kilometer rates across voltage levels. Legitquest

- **Draft Second Amendment – CERC Transmission Charges & Losses:**
  - Seeks equitable treatment of mismatch cases (like delays in commissioning), reflecting fairness in cost liability assignments.ijpiel.com

10. Australia – Building Block Regulatory Model

- The building block approach under Australia's National Electricity Rules (since ~2006) establishes a regulatory asset base and uniform revenue recovery, guiding how transmission investments (including cost allocation) are treated under regulation. Wikipedia

Research Papers & Academic Studies

1. Game-Theoretic Cooperative Allocation

- "TSO-DSOs Stable Cost Allocation..." (arXiv, 2021): Models joint procurement of flexibility among transmission and distribution operators using cooperative game theory—highlighting stable, efficient cost-sharing. arXiv

2. Transmission Fee Allocation via Stackelberg Game

- "Game-theoretic modelling of curtailment rules..." (arXiv, 2019): Addresses fair curtailment and transmission fee structures, modelling investor–generator interactions in dedicated/private line contexts (e.g., transmission fees as % of feed-in tariffs). arXiv