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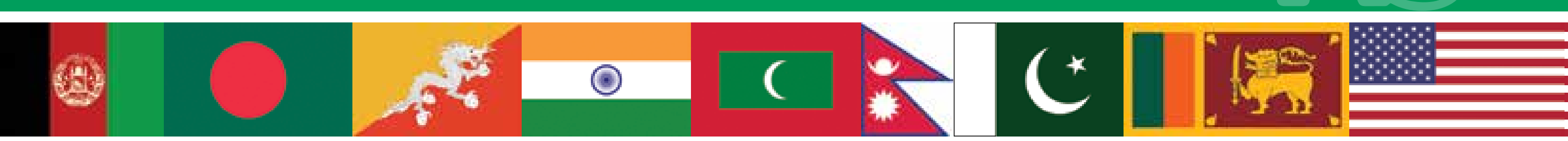
SOUTH ASIA REGIONAL INITIATIVE FOR ENERGY INTEGRATION (SARI/EI)

South Asian Countries
Power Pricing Mechanism & Recommendation for CBET



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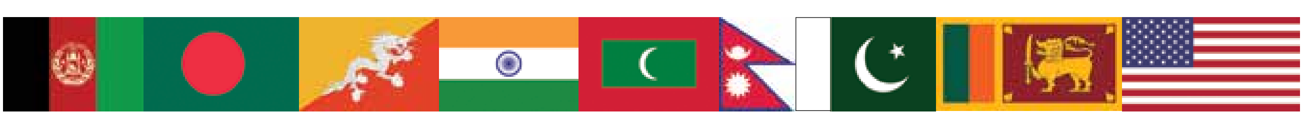

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Abbreviations

ADB	Asian Development Bank
AERA	Afghanistan Electricity Regulatory Authority
APSCL	Ashuganj Power Station Company Limited
BERC	Bangladesh Electricity Regulatory Commission
BPDB	Bangladesh Power Development Board
CBET	Cross-Border Electricity Trade
CEA	Central Electricity Authority
CEB	Ceylon Electricity Board
CERC	Central Electricity Regulatory Commission
CPGCL	Central Power Generation Company Limited
CPSU	Central Public Sector Undertakings
DABS	Da Afghanistan Breshna Sherkat
DBFOO/T	Design-Build-Finance-Own-Operate/Transfer
DOE	Department of Energy
EA 2003	Electricity Act 2003
ETFC	Electricity Tariff Fixation Commission
GoI	Government of India
IGFA	Inter-Governmental Framework Agreement
IPP	Independent Power Producer
JERC	Joint Electricity Regulatory Commission
KwH	Kilo Watt Hour
MoP	Ministry of Power
MTOE	Million tonnes of oil equivalent
NEA	Nepal Electricity Authority
PGCB	Power Grid Corporation of Bangladesh
POC	Point of Connection
PPA	Power Purchase Agreement
RgoB	Royal Government of Bhutan
RoE	Return on Equity
SAARC	South Asian Association of Regional Cooperation
SAC	South Asian Countries
SERC	State Electricity Regulatory Commission–India
TSA	Transmission Service Agreement

Preface

Cross Border Energy Trade (CBET) in South Asia started in 1970s under various water treaties in the radial mode interconnection. Over the years the market has developed. The recent agreements are based on commercial mechanisms with stable interconnections. The existing power trade in the region is about 2300 MW. CBET in these countries is either coordinated by public utilities or designated nodal agencies with terms and conditions of trade mutually agreed by parties involved.

Since the beginning of CBET in the South Asia region, the quest for security of energy supply has been its main driver. Later, countries realized its economic benefits. Now, the cost benefit is a major consideration in cross-border energy trade. CBET is also influenced by the power mix or the source of energy, which in turn is influenced by available natural energy resources and geographical location of each country as well as the government's energy strategy. Countries now realize the need for diversified energy mix. Across countries, there is also diversity in electricity demand – seasonal and daily demand, weekend and holiday etc.

IRADe is the implementing partner of USAID's flagship program, South Asian Regional Initiative for Energy Integration (SARI/EI) since 2012. The Task Force-3 (South Asia Regional Electricity Market) was established under SARI/EI with representation from each of the South Asian countries. I Sincerely hope this report on *"Power Pricing Mechanism and Recommendation for Cross- Border Electricity Trade",* which is a product of combined efforts of Task Force-3 and SARI/EI team, will encourage CBET in the region.

This report provides clarity on tariff and power procurement process necessary to remove the barriers to facilitate CBET. A coherent provision on CBET in the region would promote cross-border electricity trade, transactions and investments. The study also talks about the Transit Transmission Tariff guidance for further discussion.

I take this opportunity to thank all the members of Task Force-3 (South Asia Regional Electricity Market), the SARI/EI Project Secretariat at IRADe, and the SARI/EI consultant M/s. PricewaterhouseCoopers Private Limited (PwC) for their time and efforts in preparing this quality report. I hope the findings of this report will be actively considered by the governments of the South Asian Countries.

Dr. Jyoti Parikh
Executive Director
Integrated Research and Action for Development

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FOREWARD

United States Agency for International Development (USAID) through its South Asia Regional Initiative for Energy Integration (SARI/EI) program aims to support greater energy integration in South Asia. The region is growing rapidly (at a per capita GDP growth rate of six percent), which can be only sustained with increased and improved access to energy. However, most of the countries in the region are struggling with issues such as power shortages, high reliance's on fossil fuels and rapidly increasing power demand.

Since 2000, USAID's SARI/EI program has been working to address these challenges through technical assistance, focused analysis and capacity building to promote cross border electricity trade (CBET) thereby enhancing energy security in the region. In its current phase, IRADe a regional think tank is implementing the program, by adopting a structured framework comprising of three inter-governmental task forces and a project steering committee comprising of senior officials from the participating countries.

To support the development of a competitive power market in the region, the Task Force 3 on South Asia Regional Electricity Market was established under the program with representation from each of the South Asian countries. The report "Power Pricing Mechanism and Recommendation for Cross- Border Electricity Trade" is a result of the combined efforts of Task Force-3 and SARI/EI Team. It highlights critical issues in cross-border power trade and provides specific recommendations on the market structure, power procurement policy and tariff determination framework (for generation and transmission) for facilitating CBET in SA region.

The report includes a thorough analysis key agreement such as power purchase agreement (PPA) and transmission service agreement (TSA) prevailing within each SAC for executed cross-border transactions in SA region and recommends the model PPA for new hydro power plant model TSA for power trade in SA region.

I would like to take this opportunity to thank all the members of Task Force 3 on South Asia Regional Electricity Market, the SARI/EI Project Secretariat at IRADe and the SARI/EI consultant M/s. PricewaterhouseCoopers Private Limited (PwC) for their time and preparing this quality report. I hope the Governments of each South Asian country will actively consider the findings of this report.

Thank you

Michael S Satin

Michael Satin
Regional Energy Director,
Clean Energy & Environment Office
USAID/India

Dinesh Kumar Ghimire
Joint Secretary
Ministry of Energy,
Government of Nepal

Message- Nepal

Cross-Border Electricity Trade (CBET) in South Asia is currently being undertaken in the form of bilateral trade and is limited to eastern part of South Asia. This scenario is, however, set to change in the medium and long term with several new transmission interconnections being proposed that will enable greater integration of power systems in member countries. Such integration shall also enable trading on a multi-lateral basis wherein two countries having no common border could trade electricity through a third country acting as a transit route.

In South Asia, countries are having different power pricing and power procurement strategy depending upon their power market size and complexity, fuel dominance and market maturity. This implies that establishment of same mechanism, methodology and rules may not be followed by all countries. However, bringing clarity on front of tariff and power procurement is at top priority for flourishing the regional integration and boost the investor confidence for bulk investment in the regional assets. Such clarity is of utmost importance for removing barriers and facilitating CBET.

The Task Force-3 (South Asia Regional Electricity Market), with representation from each of the South Asian countries, has made number of key recommendations for power procurement in South Asian region through CBET which will be very fruitful to member countries for harmonizing their internal mechanism in the regional context. Favorable and coherent provisions are likely to provide certainty to cross-border electricity trade and promote investments. The study by the Task Force also talks about the Transit Transmission Tariff guidance for future eventuality.

I would like to congratulate SARI/EI and the Task Force-3 for the successful completion of the study on "Power Pricing Mechanism and Recommendation for Cross- Border Electricity Trade" which is a product of combined efforts of Task Force-3 and SARI/EI Team.

Lastly, I believe that the outcome of the study would be fully utilized by the member countries for shifting to multilateralism from bilateralism in terms of power trade so that potentials of individual countries could be exploited for the benefit of the entire region.

08.02.2018

Dinesh Kumar Ghimire
Joint Secretary
Ministry of Energy
Government of Nepal

1 Context

Cross-Border Electricity Trade (CBET) in South Asia is currently being undertaken in the form of bilateral trade and is limited to the eastern part of South Asia covering India and Nepal; India and Bangladesh; and India and Bhutan. Additionally, Myanmar imports electricity from India, Pakistan imports electricity from Iran, and Afghanistan imports from Uzbekistan, Tajikistan, and Iran. This scenario is, however, set to change in the medium and long term with several new transmission interconnections being proposed that will enable greater integration of power systems in member countries. Such integration shall also enable trading on a multi-lateral basis in the future wherein two countries which have no common border could trade electricity through a third country acting as a transit route.

As recognised during the study, countries have different power pricing and power procurement strategies depending upon the power market size and complexity, fuel dominance and market maturity. This implies that the same mechanism, methodology and rules may not be followed by all countries. However clarity pertaining to regional integration in a few prominent areas is desirable for promoting regional integration and in order to boost investor confidence for bulk investment in regional assets. **Hence the focus has been limited to tariff and power procurement that are necessary for removing barriers and facilitating CBET. It is also noteworthy that some of the recommendations may be useful for the South Asian Countries (SACs) in the context of their domestic power market**.

Based on the review of prevailing tariff mechanism and power procurement policies in SACs for CBET and their domestic power market, key recommendations have been made. Some nations may also find the recommendations useful in formulating their internal mechanisms. Favourable and coherent provisions across these parameters are likely to provide confidence in CBET transactions and promote investments.

The key factors addressed are:

- Power procurement policy/methodology of SACs
- Generation and transmission price applicable to CBET transactions
- Transit transmission tariff mechanism guidance for future eventualities

It is important to mention that the SAARC Inter-Governmental Framework Agreement (IGFA)[1] for Energy Cooperation, signed on November 27, 2014, by the Foreign Ministers of the eight member states also provides a strong basis for ensuring consistency in approaches across the above parameters.

1 http://www.saarc-sec.org/userfiles/SAARC-FRAMEWORK-AGREEMENT-FOR-ENERGY-COOPERATION-ELECTRICITY.pdf

The Ministry of Power, India has come out with guidelines on CBET, on 5th December, 2016.[2] Other than Government to Government negotiation, Tariff for import of electricity by Indian entities from generating stations (directly or through trader) located outside India may be determined, under long term/ medium term/ short term agreement, through a process of competitive bidding, which shall be adopted by the Appropriate Commission under Section 63 of the Electricity Act, 2003. In the case of hydro projects, CERC may determine the tariff as per its regulations, if approached by the generator through the government of neighbouring countries. The tariff for export of electricity to entities in neighbouring countries by Indian entities may be as mutually agreed or through competitive bidding, subject to payment of charges as applicable for transmission/wheeling of electricity through the Indian grid in the future.

As a first step in this direction the proposed recommendations aim at furthering the guidance provided by the IGFA and MoP, India guidelines on the cross border trade that govern the CBET transactions. The recommendations proposed herein are based on the following:

- Review of existing tariff and power procurement structure in the domestic market of each SACs.
- Review of the existing CBET transactions and the existing related mechanism, systems and procedures.

Purpose of Assessment

The report has been developed to establish a clear understanding of the SACs' tariff mechanism and procurement strategy. This will provide reasonable confidence to the investor and developer involved in cross-border trade transactions.

The objective of this report is to provide national regulators/empowered entities of SACs an input in the direction of reforming the tariff mechanism and developing a course of action that can be referred to for decision making on CBET in their respective countries. This will ensure consistency in the CBET transactions and will remove the constraints that have often plagued or delayed them because of the lack of consistency and clarity.

The recommendations are described in the form of principles and processes that need to be adopted on various aspects of tariff determination. In order to establish a consistent mechanism/ guideline approach on cross-border transactions in SACs the suggested framework/methodology are sufficiently flexible to work with different national legal, policy, and regulatory frameworks. The provisions allow accommodating different country circumstances, yet have a sufficiently broad application to promote consistent decision-making.

2 Ministry of Power, India Guidelines on CBET dated 5th December 2016 available at http://powermin.nic.in/sites/default/files/webform/notices/Guidelines%20for%20Cross%20Boarder%20Trade.pdf

2 Overview

The South Asian (SA) region comprises of eight nations namely, Afghanistan, Bangladesh, Bhutan, India, Maldives, Nepal, Pakistan and Sri Lanka. The region constitutes only four per cent of the world's total surface area while it contributes to nearly 23 per cent of the world's population. The region has witnessed immense economic growth over the last decade of approximately five to six per cent per annum. The following Table provides a summary of socio-economic indicators in the SA region.

Table 1: Snapshot of Socio-economic Indicators in South Asian Countries (2013)

Country	Area	Population	Population density	GDP	Growth Rate
	(1000 sq. km)	(In millions)	(Person/sq. km)	(USD billions)	(%)
Afghanistan	653	31	47	20	1.9
Bangladesh	149	157	1054	150	6.0
Bhutan	38	0.8	21	1.8	2.0
India	3287	1252	381	1875	6.9
Maldives	0.3	0.4	1333	2.3	3.7
Nepal	147	28	190	19	3.8
Pakistan	796	182	229	232	4.4
Sri Lanka	67	21	313	67	7.3
South Asia	**5137**	**1672**	**326**	**2367**	**6.6**
World	**134325**	**7125**	**53**	**75622**	**2.3**

Source: World Development Indicators, World Bank, 2015; PwC Analysis

Even though the demand for energy in the region is rising fuelled by the economic growth, there is huge variation in the energy resource endowments and consumption patterns within the region. The region is characterised by skewed distribution of the available energy resources both within a country and across the region. India and Pakistan account for the major share of coal and natural gas, respectively. However, owing to the burgeoning population levels in these nations, these resources are not sufficient to meet their energy demands. On the other hand, there are regions such as Nepal and Bhutan, which have huge hydropower potential in excess of their demand. Bangladesh is heavily reliant on natural gas reserves, which are fast depleting. Energy supply in Sri Lanka is primarily based on biomass, petroleum and hydroelectricity. Maldives is heavily dependent on diesel for its domestic needs, which is largely imported, as its own domestic resources comprise primarily of biomass. The following Table summarises available energy reserves in the countries in the South Asian region.

Table 2: Energy Reserves of South Asian Countries

Country	Coal	Oil	Natura Gas	Hydro	Biomass (RE)
	(million tons)	(million barrels)	(trillion cubic feet)	(megawatts)	(million tons)
Afghanistan	440	NA	15	25,000	18-27
Bangladesh	884	12	8	330	0.08
Bhutan	2	0	0	30,000	26.60
India	90,085	5,700	39	150,000	139
Maldives	0	0	0	0	0.06
Nepal	NA	0	0	42,000	27.04
Pakistan	17,550	324	33	45,000	NA
Sri Lanka	NA	150	0	2,000	12
South Asia	**108,961**	**5,906**	**95**	**294,330**	**223**

Source: ADB, 2012

The electricity consumption pattern also varies significantly across the South Asia region. The annual energy consumption ranges from as low as 0.17 million tonnes of oil equivalent (mtoe) for Maldives to 423.2 mtoe for India. On the other hand, per capita consumption is highest in Bhutan (2,420 kWh) and the lowest in Afghanistan (49 kWh). However, the per capita energy consumption in the region continues to be quite low as compared to the world average.

Table 3: Annual Per Capita Electricity Consumption (kWh per person)

Country	Per Capita Electricity Consumption
Afghanistan	49*
Bangladesh	281@
Bhutan	2,420#
India	1075^
Maldives	2,283*
Nepal	103
Pakistan	458
Sri Lanka	449
South Asia	**563**
World	**2,997**

Source: Cross-Border Electricity Trade in South Asia: Challenges and Investment Opportunities, Sept 2014; World Bank 2013; * = 2009 IRENA; # = 2016 RGoB; ^ = 2017 CEA; @=2015 BPDB

The South Asia region is in a phase of economic transformation and continuously moving from low growth to high growth. Energy demand and growth are interlinked with each other; therefore the energy demand in South Asia region is going to increase substantially to keep its progress story intact. Thus, to meet the growing energy demand in the region and to improve access and maintain energy security, CBET in the South Asia region will benefit the region as a whole and all member countries.

3 Power Sector Structure and Institutional Mechanism in South Asia

Electricity being a socio-economic good, the generation, transmission and distribution of power is governed by policy and regulatory frameworks in all SACs. This provides the legal basis and policy direction for the functioning and the development of the sector as a whole. Separate regulatory authorities have also been established to govern the tariff determination process in most of the SACs. Some SACs have undertaken measures to introduce reforms in the sector so as to improve its viability, attract private investments to facilitate the development of the sector and improve the reach, quality and reliability of power supply. In many countries in the region, this process has led to the enactment of the National Policy/Act and the establishment of regulatory authorities for developing and implementing the sector's regulatory framework.

Except for India and Pakistan, where electricity utilities are unbundled into generation, transmission and distribution functions, the electricity utilities are either vertically integrated or partially unbundled in other SA nations. This has been summarised below.

Vertically Integrated	Partially Unbundled	Unbundled
• Afghanistan (DABS) • Maldives (FENAKA) • Nepal (NEA) • Sri Lanka (CEB)	• Bangladesh (separate transmission utility) • Bhutan (separate generation utility)	• India (separate G, T, D utilities) • Pakistan (separate G, T, D utilities)

The following Table provides an overview of the institutions undertaking policy, regulation and power generation, transmission, system operation, distribution and trading within each of the South Asia nations.

Table 4: Overview of Institutes undertaking Policy, Regulation and Power Generation, Transmission, System Operation, Distribution and Trading in each South Asian country

Country	Policy	Regulation	Generation	Transmission	System Operation	Distribution	Trading
Afghanistan	Ministry of Energy and Water (MEW)	Afghanistan Electricity Regulatory Authority (AERA) (Proposed)	DABS	DABS	DABS	DABS	DABS
Bangladesh	Ministry of Power, Energy and Mineral Resources (MPEMR)	Bangladesh Energy Regulatory Commission (BERC)	BPDB, EGCB, APSCL, NWPGC, IPPs, SIPPs, Rental Plants	PGCB	PGCB	BPDB, WZDPC, APSCL, DPDC, DESCO, REB	BPDB
Bhutan	Ministry of Economic Affairs (MEA)	Bhutan Electricity Authority (BEA)	Druk Green Power Corporation (DGPC)	Bhutan Power Corporation (BPC)	BPC (NLDC)	BPC	
India	Central: Ministry of Power under the Government of India) State: Power/Energy Department under the State Government	Central: CERC State: SERCs/ JERCs	Central: NTPC, NHPC, NPCIL, UMPPs, IPPs, MPPs State: State-owned GenCos, IPPs,CPPs	Central: POWERGRID (CTU), Private/JV Licensees State: STUs, Private/JV Licensees	Central: POSOCO (NLDC & 5 RLDCs) State: SLDCs	Central: Nil State: State-owned Discoms,Private Licensees,Distribution Franchisees	Central: Inter-state Licensees State: Discoms / TradeCos (Include State Holding Cos) / Intra-state Licensees
Maldives	Ministry of Environment and Energy (MOEE)	Maldives Energy Authority (MEA)	STELCO, FENAKA	STELCO, FENAKA	STELCO, FENAKA	STELCO, FENAKA	-
Nepal	Ministry of Energy (MoE)	Electricity Tariff Fixation Commission (ETFC) under Department of Electricity Development (DOED)	Nepal Electricity Authority (NEA), IPPs	NEA	NEA	NEA	NEA
Pakistan	Ministry of Water and Power (MOWP)	National Electric Power Regulatory Authority (NEPRA)	State-owned generating companies formed after restructuring of WAPDA (CPGCL, JPCL, LPGCL, NPGCL) & other IPPs	National Transmission & Despatch Company (NTDC)	NTDC	KESC & Distribution Companies formed after restructuring of WAPDA (total 10 in nos.)	-
Sri Lanka	Ministry of Power and Energy (MOPE)	Public Utilities Commission of Sri Lanka (PUCSL)	Ceylon Electricity Board (CEB), IPPs	CEB Transmission Licensees	CEB Transmission Licensees	CEB Distribution Licensees 1-4 LECO	-

Abbreviations: AERA - Afghanistan Electricity Regulatory Authority; APSCL - Ashuganj Power Station Company Limited; BERC - Bangladesh Energy Regulatory Commission; BPDB - Bangladesh Power Development Board; CEB - Ceylon Electricity Board; CERC - Central Electricity Regulatory Commission; CPGCL - Central Power Generation Company Limited; CPP - Captive Power Plant; CPSU - Central Public Sector Undertakings; DABS - Da Afghanistan Breshna Sherkat; DESCO - Dhaka Electric Supply Company Limited; DL - Distribution Licensee; DOED - Department of Electricity Development; DPDC - Dhaka Power Distribution Company; EGCB - Electricity Generation Company of Bangladesh; ETFC - Electricity Tariff Fixation Commission; IPP - Independent Power Producer; IPP - Independent Power Producers; JERC - Joint Electricity Regulatory Commission; JPCL - Jamshoro Power Company Limited; LECO - Lanka Electricity Company (Private) Limited; LPGCL - Lakhra Power Generation Company Limited; MPP -Merchant Power Plant; NEA - Nepal Electricity Authority; NEPRA - National Electric Power Regulatory Authority; NLDC - National Load Dispatch Centre; NPGCL - Northern Power Generation Company Limited; NTDC - National Transmission & Despatch Company; NWPGC - North West Power Generation Company Limited; PGCB - Power Grid Company of Bangladesh Limited; POSOCO - Power System Operation Corporation Limited; PUCSL - Public Utilities Commission of Sri Lanka; REB - Rural Electrification Board; RLDC - Regional Load Dispatch Centre; SERC - State Electricity Regulatory Commission; SIPP - Small Independent Power Producers; SLDC - State Load Dispatch Centre; STELCO - State Electricity Company Limited; UMPP - Ultra Mega Power Project; WAPDA - Water and Power Development Authority; WZPDC - West Zone Power Distribution Company

4 Power Procurement

Tariff determination for the sale / purchase of power is governed by applicable power procurement policy/ regulatory framework in the country. A power procurement policy provides the framework and guidelines which shall be adopted by the procurer to assess the requirement of power in the ensuing years and to determine the best possible source of power to meet such requirement in an efficient and economic manner.

The following Table provides a summary of the power procurement policy / framework in each of the countries in the SA region. Except India and Sri Lanka (through a recent amendment in the Sri Lanka Electricity Act 2009), no other country within the SA region has established separate guidelines for power procurement. This is because most of the countries have vertically integrated power utilities, which undertake generation, transmission and distribution of power. Further, in many cases power procurement from independent power producers is generally based on negotiations.

Table 5: Overview of Power Procurement Framework in Countries of the South Asia Region

Country	Power Procurement Framework
Afghanistan	Power utility in Afghanistan namely DABS is a vertically integrated utility and at present a separate power procurement policy has not been notified. The functioning of the vertically integrated utility DABS is governed by the MEW, while a separate regulatory body is being set up. Further there is no segregation of policy for long, medium &short-term power procurement.
Bangladesh	The generation and distribution of electricity is carried out by a single entity in the country i.e. BPDB, while the transmission of electricity is being carried out by PGCB. There is no separate power procurement policy in such a scenario. However power procurement from IPPs is carried out on a negotiated/competitive/ regulated basis.
Bhutan	Bhutan is a power surplus country and most of the hydropower plants are export oriented. A separate power procurement policy has not being notified in the country.
Maldives	Policy framework for power procurement and tariff for the vertically integrated utility STELCO and FENAKA is governed by the Ministry of Environment and Energy and Maldives Energy Authority. There is no separate power procurement policy.
Nepal	NEA, vertically integrated utility in Nepal, handles generation, transmission and distribution functions. Nepal has not notified a separate power procurement policy and is procuring power from IPP only on a negotiated basis.
Pakistan	NTDC is currently empowered as the central power purchasing agency to procure power on behalf of the eight distribution companies of erstwhile WAPDA, while a separate power procurement policy has not been notified.

Cont.

Table 5 Cont.

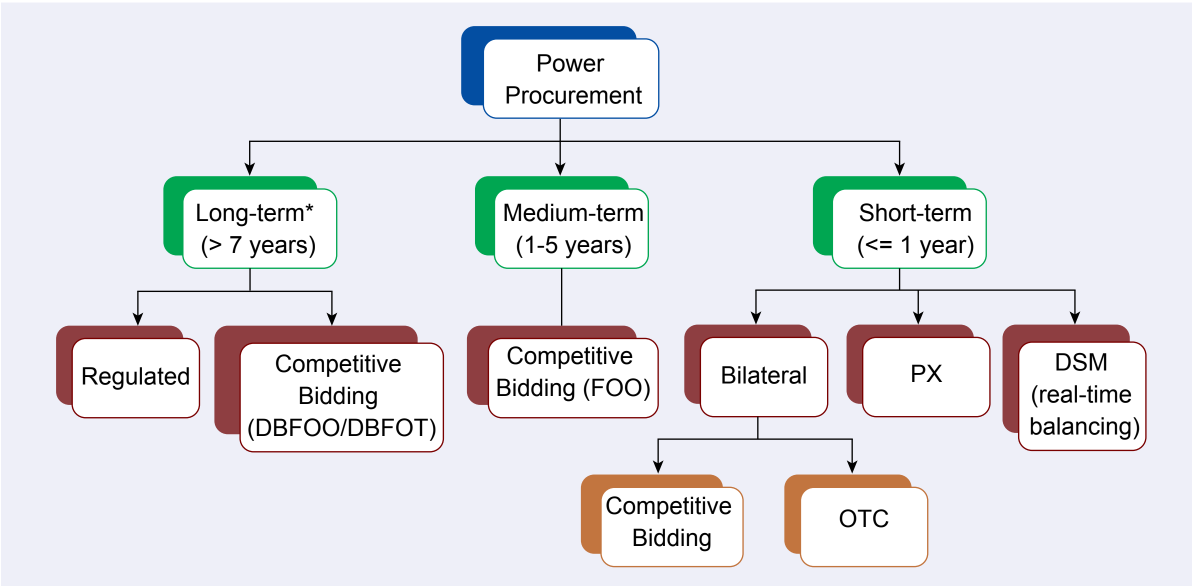
Country	Power Procurement Framework
India	• The Indian Electricity Act 2003 ("E Act") provides the framework for power procurement. • Power can be procured by the distribution utilities in the long-term either through the regulated route (Section 62) wherein the policies/ regulations/guidelines for procurement of power are specified by the respective SERCs (State Electricity Regulatory Commissions) and/or through the competitive bidding route (Section 63) wherein standard guidelines for power procurement have been specified by the Union MoP. • In case of Section 62, the regulations are framed by SERCs specifying the framework and procedures for the assessment of demand-supply scenario in the short, medium and long-term; criteria/process for procurement of power, entering into Power Purchase Agreement (PPAs) and approval of legitimate costs for recovery through retail tariff. • The E Act also provides for procurement of power in the medium-term through competitive bidding and the short-term through bilateral trade(through trader / direct), power exchanges and real-time balancing mechanism. • In case of procurement of power under the competitive bidding route in case of the long-term/ medium-term it is specified by the respective state governments, which are in turn guided by standard bidding guidelines specified by MoP. • The procurement of power under the short-term route through bilateral (through trader) / exchanges/ real-time balancing mechanism is governed by regulations notified by the Central Electricity Regulatory Commission (CERC) from time to time.
Sri Lanka	• The transmission licensee will take approval from the Regulatory Commission to procure power from new generating stations or the expansion of an existing station based on least-cost long-term generation expansion plan. • Power from stations adhering to least-cost long-term generation plan and duly approved by the Commission and the Cabinet of Ministers and those permitted by the Sri Lanka Sustainable Energy Authority are exempted from the tendering process. • Terms and conditions shall be as per the PPA entered with the transmission licensee after taking approval from the Commission.

The following sub-section provides a brief overview of the power procurement guidelines/ framework in India and Sri Lanka.

4.1.1. Power Procurement Framework in India

The Indian Electricity Act 2003 provides the framework for power procurement. As per the Act, power can be procured either through the regulated route (Section 62) and/or through the competitive bidding route (Section 63) in the long-term. The Act also provides for procurement of power in the medium-term through the competitive bidding route and in the short-term through bilateral, power exchanges and real-time balancing routes as specified in the following diagram.

Figure 1: Power procurement routes available to buyers in India



Abbreviations: DBFOO/T - Design-Build-Finance-Own-Operate/Transfer; OTC - Over The Counter; PX - Power Exchange; DSM - Deviation Settlement Mechanism

Note:* The long-term competitive bidding guidelines are applicable only for thermal projects. All hydro projects are exempt from competitive bidding till FY 2022 and would be through the regulated route; DBFOO term - Power supply agreements signed for a period of 7 years and above up to a period 25 years from the commencement of power with a provision of extension of 5 years at the option of either party (Amendment to DBFOO Guidelines, May 2015).

The policies/ regulations/guidelines for the procurement of power by distribution utilities under the regulated route are specified by the respective SERCs (State Electricity Regulatory Commissions). These Regulations provide the framework and procedures for assessment of demand-supply requirement in the short, medium and long-term and criteria/process for procurement of power, entering into Power Purchase Agreement (PPAs) and approval of legitimate costs for recovery through retail tariff.

The standard power procurement policies by SERCs under the regulated route specify the procedure for assessment of power availability and requirement, power purchase agreement and the rate/tariff of power. The assessment of power availability and requirement include specifying assessment of power availability, demand forecasts, rationale / basis for demand forecasts, procedures and timelines for power procurement, etc. The PPA defines the commercial arrangements related to scheduling, energy accounting, deviation settlement, dispute resolution, etc. as well as the rate/tariff of power.

The procurement of power under the competitive bidding route in case of long-term / medium-term is governed by the standard bidding guidelines along with Standard Bidding Documents (SBDs) notified by the Ministry of Power (MoP), Government of India. The respective state governments may modify the bidding documents issued by the MoP for power procurement by distribution companies with approval from respective SERCs.

The procurement of power under the short-term route through exchanges / real-time balancing is governed by guidelines notified by the Ministry of Power (MoP) and regulations notified by the Central Electricity Regulatory Commission (CERC) from time to time.

4.1.2. Power Procurement Framework in Sri Lanka

In 2013, an amendment to Section 43 of the Sri Lanka Electricity Act, 2009 was notified to include provisions related to the procurement of power. The salient features included:

- A transmission licensee shall submit proposals to the regulatory commission so as to proceed with the procuring of any new generating plant or for the expansion of the generation capacity of an existing plant based on the future demand forecast as specified in the Least-Cost Long-Term Generation Expansion Plan.
- Upon approval of the Commission, the transmission licensee shall, in compliance with any rules that may be made by the Commission relating to procurement, call for tenders by notice published in the Gazette, to develop a new generating plant or to expand the generation capacity of an existing generating plant.
- The exception to above shall be any new generating plant or expansion of any existing generating plant that is being developed in accordance with the Least-Cost Long-Term Generation Expansion Plan duly approved by the Commission and the Cabinet of Ministers or through a permit issued by the Sri Lanka Sustainable Energy Authority for generation from renewable energy sources.
- Upon the closure of the tender, the transmission licensee shall, through a properly constituted tender board, ask the Commission for its approval along with the draft Power Purchase Agreement, describing the terms and conditions of such purchase.
- The Commission shall be required, on receipt of any recommendations of the transmission licensee, to grant its approval at its earliest convenience, where the Commission is satisfied that the recommended price for the purchased electricity generating capacity meets the principle of least cost and the requirements of the Least-Cost Long-Term Generation Expansion Plan and the same is within the accepted technical and economical parameters of the transmission licensee.

In case of the SA region, at present there is no common power procurement policy/ guidelines/ framework established for cross border power procurement.

4.1.3. Recommendations for Power Procurement in South Asian Region Through CBET

Each country is sovereign by itself, governed by its own policies and laws; there is a need to coordinate the regulations governing trade in electricity in order to facilitate CBET. Common power procurement guidelines for promoting cross-border electricity trading if formulated will facilitate CBET in the SA region greatly. The purpose is to essentially set out the standard practices based on which electricity can be traded. At the time of framing such a guideline, care has been taken so that the existing framework for power procurement within each nation is not unduly affected. For example considering power procurement through the competitive bidding route may not be feasible in case of the trade of hydropower through India (as per Tariff Policy 2016, hydropower is exempted from the competitive bidding route and shall be procured through the regulated route up to FY 2022). Further, the common power procurement guidelines should be able to address issues such as what should be the mode of procurement or period for which power is contracted or tariff determination principles, etc. In order to do so we have studied the existing terms and conditions based on which electricity trade is presently been conducted within the SA region.

Based on the review of existing PPAs, we have made recommendations related to term, mode and principles of tariff determination, which have been provided in the following Table.

Table 6: Recommendation Summary for Power Procurement in the South Asian Region

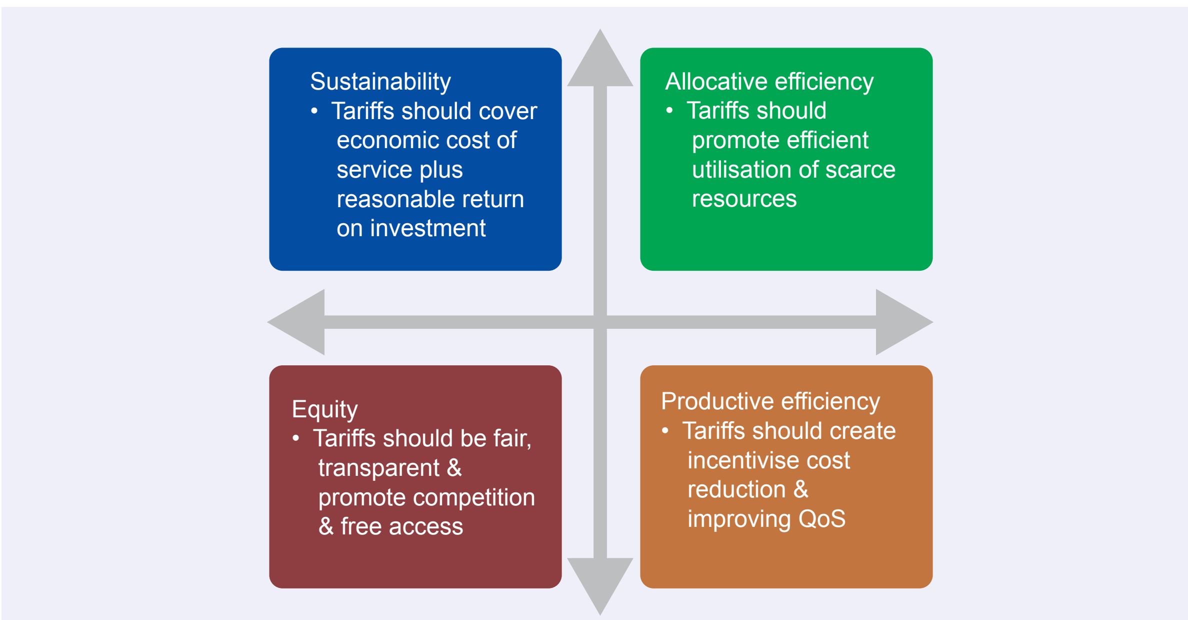
Salient features of power procurement policy	Recommendation summary
Term	**Long-term:** Typical term of the long-term agreement should be commensurate with the useful life of the generating asset. Hence, term of long-term agreement for thermal assets to be at least 25 years and hydro assets to be at least 35 years. This is as per the prevailing practice in most of the PPAs reviewed cross-border and within the country. **Short/ Medium-term:** The timeframe for short-term and medium-term contracts to be aligned with India as it is the largest demand centre within the SA region and these contracts are already widely used in India. Therefore, the term of short-term and medium-term is recommended to be less than one year and one to five years, respectively.
Mode of procurement	There are broadly two options for power procurement viz. competitive bidding or cost-plus/negotiated (regulatory mechanism). **Long/ Medium-term:** • ***Hydro projects:*** Procurement from hydro projects is recommended on cost-plus/ negotiated basis. Hydro projects in India are exempted from competitive bidding till FY 2022 and also all existing CBET projects between Nepal-India and Bhutan-India have been established through the negotiated route. • ***Thermal projects***: Procurement from thermal projects can be on a competitive bidding basis. India has already made competitive bidding mandatory for power procurement (except hydro) by distribution utilities. Further, competitive bidding has been adopted by Bangladesh for procurement for 250 MW for a 3 year term from India. In addition, Bangladesh has also attempted to procure additional power through competitive bidding. Thus, procurement from thermal projects is recommended on a competitive bidding basis. **Short-term:** In case of short-term contracts above a certain MW (to be defined by the respective SAC), buyers shall adopt the competitive bidding route for tariff determination. This would also ensure transparency and promote a competitive environment. For the procurement of smaller quantum, buyers may adopt the negotiation route.
Tariff structure	**Long/ Medium-term:** The tariff structure to be adopted in line with the prevailing practice in each SAC and existing CBET agreements in the SA region viz. two-part tariff structure for thermal generators and single-part tariff structure for hydro generators. **Short-term:** Typically, short-term power supply contracts stipulate the energy (in MU or MW & hours) to be transacted with a provision of variation to a certain percentage, say +/-20% in actual delivery. Hence, a single part tariff is more apt in this case and also is as per prevailing practice in short-term PPAs within India and short-term CBETs between India-Nepal.
Tariff recovery by generator	In case of single-part tariff, the tariff shall be recovered based on scheduled energy at the delivery point (failure to off-take power by buyer shall be treated as deemed delivery). In case of two-part tariff, fixed charge shall be recovered based on declared capacity (linked with pre-defined normative availability factor) and variable charge shall be recovered based on scheduled energy at delivery point.

5 Tariff Determination Framework

Prevailing in each South Asian Country

Tariff determination in the power sector is driven by the legislative and policy framework formulated and established by the respective Central Government and state governments(s) as the case may be. The guiding principles for tariff determination to ensure economic and efficient pricing are similar across SACs i.e. (i) promote efficiency; (ii) attract investment; (iii) ensure financial viability; and (iv) be simple and transparent. The following diagram details the core guiding principles for the determination of tariff followed in the SA region:

Figure 2: Guiding principles for tariff determination



5.1 Generation tariff determination framework in various South Asian Countries

The tariff determination process for generation and sale of power varies within each country in the South Asia region. Depending on the power procurement route adopted, tariff is either determined using principles specified in regulations / guidelines, discovered through a process of competitive bidding and / or provided in PPAs or negotiated with developers. However, in most of the countries in the SA region, the majority of power produced is by government-owned vertically integrated utilities and as such the tariff for generation function is bundled in the retail tariff.

Table 7 below provides a comparison of different tariff determination principles/ methodology adopted by generation utilities in SACs.

Table 7: Comparison of Principles/ Approach for Generation Tariff across Countries in the SA Region

Country	Regulated Tariff	Competitive Bidding/ PPA based Tariff	Structure of Tariff (Single Part / Two Part)
Afghanistan	Yes (determined by MEW/DABS)	No	Single-part
Bangladesh	Yes	Yes (selective)	Two-part
Bhutan	Yes	No	Single-part
India[3]	Yes	**Thermal- competitive bidding** **Hydro- regulated route**	**Two-part; Deviation from Schedule -settled through DSM/UI**
Maldives	Yes	No	Two-part
Nepal	Yes	No (fixed upfront for hydro plants of <=100 MW capacity)	Single-part
Pakistan	Yes	Yes (selective)	Two-part
Sri Lanka	Yes	**No (fixed upfront for RE plants)**	Single-part

The following sub-section details the 'as-is' scenario of the process followed for determination of generation tariff in each of the countries in the SA region.

Afghanistan

The AERA (Afghanistan Electricity Regulatory Authority) to be set-up (at present in the draft stage) shall undertake tariff determination, categorise customers for the purpose of tariffs, approve or adjust tariff schedules of licensees in accordance with the provisions of the law, etc. Any licensee having significant market power, or if otherwise required by the law to have regulated tariffs, shall publish up-to-date tariffs for all electricity services on the basis of following general principles.

General principles for determination of tariff: The licensee may set tariffs which, charged over the annual volume of sales, collectively reflect the justified total annual costs of licensee for the provision of licensed services, plus a reasonable rate of return.

The major components of tariff include the following:

- Operation and maintenance cost
- Debt service costs
- Licensee fees
- Depreciation
- Statutory taxes
- Costs of fuel
- All other reasonable costs necessary and proper to the conduct of the Licensed activities.

3 Regulated tariffs for hydro in a few cases are based on a single part tariff structure. Also, there are instances of negotiated tariffs for short-term PPA with single part tariff structure.

Bangladesh

The BERC (Bangladesh Energy Regulatory Commission) notified the Generation Tariff Regulations in 2008, which provide for a "cost-plus approach" for the determination of generation tariff from conventional projects. The tariff structure is two-part wherein one part consists of the fuel cost involved in the generation of electricity and the other part will recover the plant's fixed cost requirement. While the fuel cost is passed on at actuals, BERC has defined certain norms for the fixed (capacity) cost components of the generation licensee, the break-up of which is enumerated below.

i. **O&M Costs:** The Commission has not provided any norms for the determination of O&M expenses and the same are approved on the actual costs incurred under various cost heads as stated below:
   - Generation Expenses: Comprise of expenses related to the operation of the plant such as operation supervising and engineering, electric expenses, rents, maintenance of structures, supervision etc.
   - Customer Account Expenses: Include supervision, customer records and collection, uncollectable accounts and miscellaneous customer account expenses
   - Sales Expenses: Include selling, advertising and other miscellaneous sales expenses
   - A&G Expenses: Include administrative and general expenses such as salaries, office supplies and expenses, rents, insurance, employee pensions, Commission's license fees etc.

ii. **Income Tax:** The amount of income tax to be included for tariff rate design during the financial year is the actual amount of income tax paid to the government. Other forms of taxes such as VAT and custom duty are included as part of the cost of the asset. The proposed increase in tariff (revenue) based on revenue gap approved by the Commission is grossed up at the prevailing income tax rate to compensate for the tax paid by the licensee.

iii. **Depreciation Cost:** Straight Line Method is used for computing depreciation costs based on the useful life of the asset.

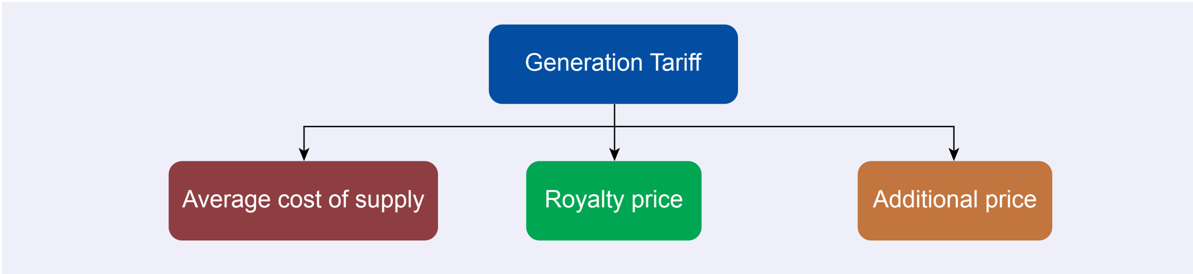
iv. **Return on Rate Base:** It is computed based on the following formula:

Tariff Rate of Return = [(Equity Capital × Cost of Equity) + (Debt Capital × Cost of Debt)]/ [Equity Capital + Debt Capital]

The cost of debt is the actual cost of the licensee's loan portfolio, while the cost of equity is approved on a case to case basis. The tariff rate of return for government-owned companies is considered equal to the government's cost of capital and considered the most recent auction rate of the Treasury Bill issued by the Central Bank.

Bhutan

The generation tariff applicable for procurement of power in Bhutan includes the following components.



i. Determination of Average Cost of Supply: The total cost of supply for a licensee in any year is determined based on the following formula.

TC = OM + DEP + RoA + RoWC
Where,
RoA = WACC * NA
RoWC = WACC * [REV * ARREARS/ 365 + Inventories
WACC = CoE * (1 - Gearing)/(1 - Tax) + CoD * Gearing

Where,

- TC is the total cost of supply
- OM is the allowance for operating and maintenance costs including any regulatory and other fees
- DEP is allowance for depreciation of assets
- RoA is return on fixed assets
- RoWC is the return on working capital
- WACC is the weighted average cost of capital
- NA is the net value of all the fixed assets at the start of the year
- COE is the cost of equity in percentage determined by BEA
- Gearing ratio is the standard ratio of debt to total fixed assets, as determined by the Authority
- CoD is the cost of debt, as percentage, being the weighted average interest of licensee's loan
- Tax is the prevailing rate of company taxation, as a percentage

The average cost of supply is taken as the ratio of the discounted annual cost of supply to the discounted energy volumes, with discounting applied over the tariff period using the WACC.

ii. Determination of Royalty Price: For each licensee, the Authority determines the volume of royalty energy to be supplied to the government, which in turn supplies the BPC at discounted rates to keep the end consumer tariffs low, for each month of the calendar year based on the average generation of the licensee of the past three years. This volume of royalty energy over twelve consecutive months in a calendar year shall not exceed 15 per cent of the actual annual energy generated by licensees, adjusted for auxiliary consumption.

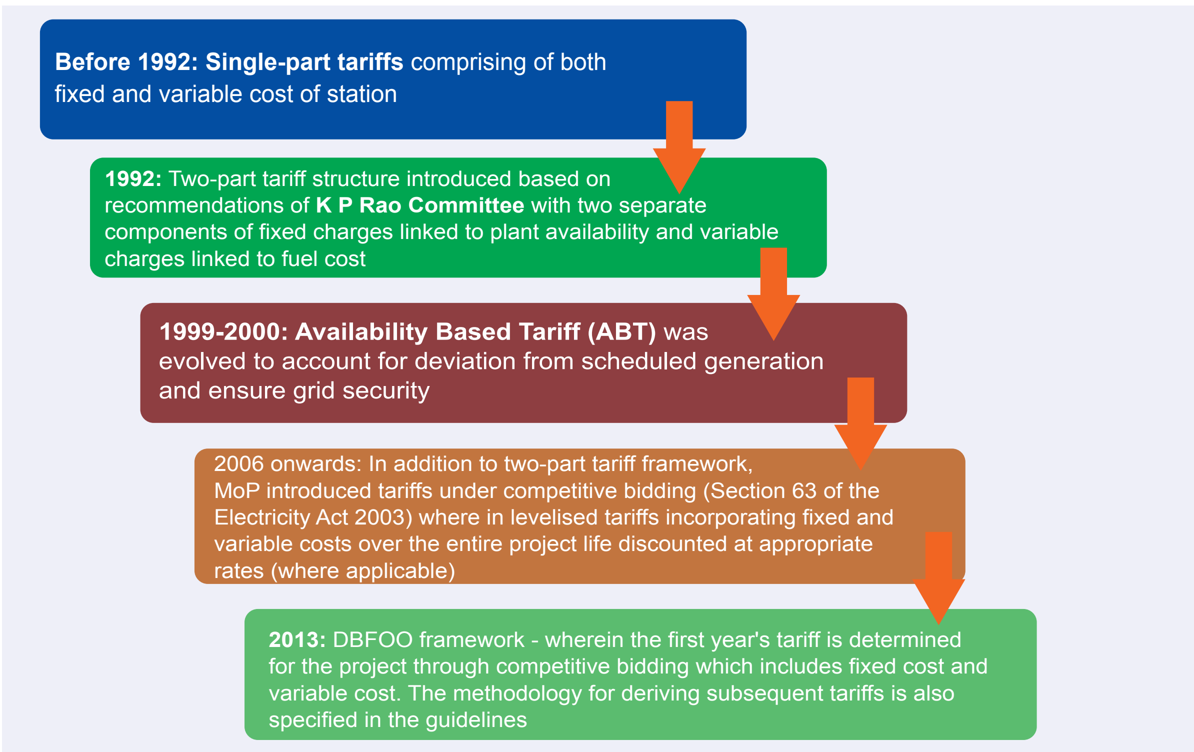
The royalty price is the average cost of supply lower than the ratio of discounted subsidy amounts to the discounted royalty energy, with discounting applied over the tariff period using the WACC. This power is discounted as it is supplied by the government to BPC to cross subsidise end consumers.

iii. Determination of Additional Price: Any energy delivered by a Generation Licensee to a Distribution Licensee above the Royalty Energy shall be termed as Additional Energy (i.e. over and above 15% cap of the Royalty Energy). The price for Additional Energy, termed as the Additional Price, shall be equal to the Average Cost.

India

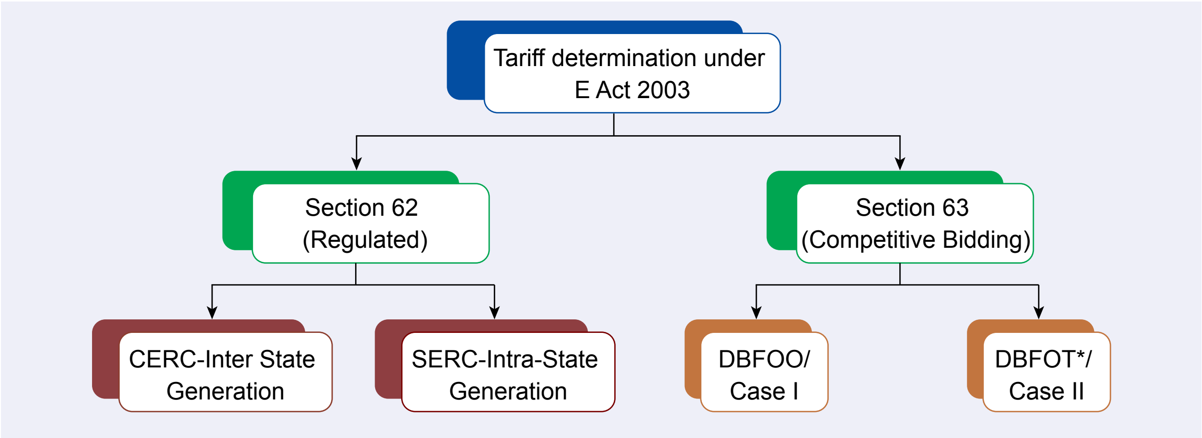
In India, the generation tariff has evolved over time in accordance with the reforms. Before 1992, single part tariff was charged for the recovery of the cost of power generated; since then several changes have been made based on the K P Rao Committee's recommendations of as well as policy changes in the sector. The key stages of evolution of generation tariff in India are shown below in Figure 3:

Figure 3: Evolution of generation tariff determination in India



The Indian Electricity Act 2003 provides for two modes of tariff determination for power generation utilities depending on the applicable power procurement framework. The first mode is the '**regulated route**' under Section 62 of the Act, which is used by regulators to determine the tariff of power plants set up under the Memorandum of Understanding (MOU) route. Under this mode, the tariff for power procurement from the generation company is determined by the Appropriate Commission (CERC/SERC) on the basis of principles specified under the Tariff Regulations and this approved tariff is adopted by the procuring distribution licensee. The second mode for generation tariff determination is by way of '**competitive bidding**', wherein the tariff is discovered through a transparent competitive bid process which is run as per the guidelines issued for this purpose by the Central Government under Section 63 of the Act.

Figure 4: Modes of tariff determination in India



Note: *Under review by MoP; All hydro projects are exempted from competitive bidding till Dec 2015

Mode I (India) - Tariff Determination under the Regulated Route

Under the regulated route, tariff determination is undertaken by the appropriate Commission, by reviewing the tariff filings of the generation company on the basis of relevant regulations for determination of tariff specified by the Commission. The CERC regulates the tariff of power generating companies owned or controlled by the Central Government or if a generating company enters into or otherwise has a composite scheme for generation and sale of electricity in more than one state while the SERCs are responsible for tariff determination for the generating plants at the intra-state level.

Under this route, the regulators viz. CERC and SERCs:

- Formulate regulations for specifying norms and methodology for determination of revenue and tariff
- Determine prudent capital costs and approve additional capitalisation for generating plants
- Review annual / multi year tariff filings and approve annual / multi-year Aggregate Revenue Requirement (ARR)
- Carry out Annual Performance Review based on provisional data to assess the actual performance vis-à-vis the targets approved by the Commission
- True-up based on audited data and treatment of surplus/deficit (if any).

The Electricity Regulatory Commission has adopted the following approaches for the determination of generation tariff:

- *Annual Tariff Framework:* Under the annual framework for tariff determination, the ARR and tariff for the generation company is determined annually before the start of the ensuing financial year. The basis for ARR and tariff determination are the procedures and norms specified in the Tariff Regulations, the forecasts for the ensuing year submitted by the generating company and review of trends of actual financial and operational performance for the previous years.

- *Multi-Year Tariff (MYT) Framework:* Under the MYT framework the ARR for the generation company is determined for a predefined control period of three or five years. The basis for ARR and tariff determination are the procedures and norms specified in the Tariff Regulations, the forecasts for the control period submitted by the generation company and review of trends of actual financial and operational performance for the previous years. The MYT framework provides certainty to both investors and consumers on the regulatory framework and approach while also providing room to the generation company to plan for improvement in performance to achieve additional gains. The tariff may be set for the entire control period but is reviewed annually on the basis of updated information of the concerned year. At the end of the control period, a true-up exercise is undertaken to review the actual performance vis-à-vis the approved forecast. The surplus/deficit calculated with due regard to the Tariff Regulations is passed on to the ARR of the generating company for the ensuing year. Under the MYT framework, the financial and operating parameters are clearly segregated into controllable and uncontrollable factors:
    - Uncontrollable parameters refer to parameters, which are beyond the control of the utility. These parameters include inflation, demand, fuel prices etc. Under the prevailing framework, CERC allows the pass through of impact of variation in cost/ revenue due to uncontrollable parameters.
    - Controllable parameters refer to all parameters, which are within the control of a utility such as capital costs, O&M cost, availability, station heat rate etc. The targets for controllable components are set so as to incentivise improvement in performance and penalise poor performance. Under the prevailing framework, CERC has specified a risk sharing mechanism for variation in costs / revenue due to controllable parameters. Costs are trued-up annually i.e. projected costs determined at time of tariff setting are compared with actual costs based on audited annual accounts and difference (if found prudent by appropriate Commission) is passed on to the beneficiaries through the tariff determined for the next year.

The CERC and SERCs have adopted a building block approach to determine revenue requirement of the generation utility, which comprises of financial as well as operational parameters as summarised in Annexure-1.

i. Tariff for thermal generating plants

The tariff for supply of electricity from a thermal generating station comprises of two parts, namely, **capacity charge** (for recovery of annual fixed cost) and **energy charge** (for recovery of primary and secondary fuel cost and limestone cost where applicable).

a. The **capacity charges** are derived on the basis of annual fixed cost (AFC) which comprises of the following components:
    - Return on equity
    - Interest on loan
    - Depreciation
    - Interest on normative working capital
    - Operation and maintenance (O&M) expenses

    The fixed cost of a thermal generating station is computed on an annual basis based on norms specified by CERC as detailed above in Annexure-1 or by appropriate SERCs for intra-state generating stations, and recovered on a monthly basis (in million INR) under capacity charge based on Normative Annual Plant Availability Factor (NAPAF). The total capacity charge payable for a generating station shall be shared by its beneficiaries as per their respective percentage share/allocation in the capacity of the generating station.

b. The **energy charges** pertain to the variable cost component for recovery of variable components of tariff such as primary fuel. The determination of energy charge is based on the following:

- Landed cost of primary fuel
- Landed cost of secondary fuel oil
- Operating norms as specified in the regulations

The landed cost of primary fuel and secondary fuel for tariff determination is based on the actual weighted average cost of primary and secondary fuel of the three preceding months, and in the absence of landed costs for the three preceding months, latest procurement price of primary fuel and secondary fuel for the generating station, before the start of the tariff period for existing stations and immediately preceding three months in case of new generating stations is taken into account. The landed cost of fuel (coal/lignite) for the month includes price of fuel inclusive of royalty, taxes and duties, transportation cost and normative transit and handling losses. Any variation in landed price of primary fuel (LPPF) is allowed as pass-through in the tariff. The normative values of the various parameters such as auxiliary consumption, gross heat rate etc. along with calorific value of the primary and secondary fuels are considered while arriving at the energy cost.

ii. Tariff for hydro generating plants

The CERC has segregated the AFCs for a hydro power plant into two components - capacity charges and energy charges wherein the fixed cost of the hydro power plant computed on an annual basis shall be recovered on a monthly basis under the capacity charge (inclusive of incentive) and energy charge shall be payable by the beneficiaries in proportion to their respective allocation in the saleable capacity of the generating station.

The capacity charge (inclusive of incentive) payable to a hydro power plant for a calendar month shall be:

Capacity Charge (INR) = AFC × 0.5 × NDM/NDY × (PAFM/NAPAF)

The **energy charge** payable to a hydro power plant for a calendar month shall be:

Energy Charge (INR) = (Energy Charge Rate in INR/kWh) × {Scheduled energy for the month in kWh} × (100 - FEHS)/100;

Energy Charge Rate (INR/kWh) = AFC × 0.5 × 10/ {DE × (100-AUX) × (100- FEHS)}

Where,

- AFC is Annual Fixed Cost as specified by the Commission for the year
- NDM is Number of days in a month
- NDY is Number of days in a year
- PAFM is Plant availability factor achieved during the month, in percentage

- NAPAF is Normative Plant Availability Factor defined in the Regulations, in percentage
- FEHS (%) is Free energy for the home State
- DE (MWh) is Annual design energy

iii. Tariff for renewable energy plants

There has been a major thrust for renewable energy (RE) generation in India in the past decade, wherein generation capacity has increased by around 10 times from 3 GW in the year 2004 to 32 GW at present. The RE generation potential in India is vast. With GoI's thrust on RE power including harnessing solar power, India looks to making huge strides in RE power in the future.

The CERC has framed regulations, from time to time, for the determination of generic tariff for each type of RE based generating plant such as biomass, bagasse, solar, wind, small hydro, etc. The component of tariffs include capital and operating costs in case of wind, small hydro and solar based RE projects and also includes the fuel component in case of biomass and bagasse based projects. The SERCs also frame generic tariff guidelines for the procurement of power by intra-state distribution licensees. Further, large capacities in recent times are being procured through competitive bidding, especially in the solar sector.

CERC has also introduced a concept of Renewable Energy Certificates (RECs) at the national level to develop the market and increase demand across the nation for RE based generation. Under this framework, the developers sell the electricity generated directly to the state distribution licensee(s) at the average pooled cost of power, while the RECs are sold separately at the power exchanges in India. The National Load Despatch Centre (NLDC) is the nodal agency for accrediting, verifying and selling RECs to developers. 1 REC = 1 MWh of power. The CERC determines the floor price and forbearance price for trading of solar and non-solar RECs.

Incentive and Penalty Framework: The incentive/ penalty framework is restricted to the 'controllable parameters' as defined in the Tariff Regulations. Under the prevailing tariff framework (i.e. the CERC Tariff Regulations, 2014), the incentive/ penalty framework covers the following parameters:

- Additional Return on Equity (RoE) is allowed if projects are commissioned within the timelines specified in the Regulations
- Incentives are linked to actual performance against specified Normative Annual Plant Load Factor (NAPLF). The incentives are provided on a per unit basis for achievement of PLF higher than NAPAF.

In addition to these incentives/penalties, the financial gains earned by a generating company on account of controllable parameters are shared between the generating company and the beneficiaries on a monthly basis with annual reconciliation. The financial gains are shared in the ratio of 60:40 between the generating station and the beneficiaries.

Billing and Payment of Charges

The generating company raises bills on a monthly basis for capacity charge and energy charge in accordance with these regulations, and payments are to be made by the beneficiaries directly to the generating company.

Payment of the capacity charge for a thermal generating station is shared by the beneficiaries of the generating station as per their percentage shares for the month (inclusive of any allocation out of the unallocated capacity) in the installed capacity of the generating station.

Payment of capacity charge and energy charge for a hydro generating station is shared by the beneficiaries of the generating station in proportion to their shares in the saleable capacity. The saleable capacity is determined after deducting free energy corresponding to the home State.

Mode II (India) - Tariff Under the Competitive Bidding Framework

As mentioned above on power procurement in India, power is procured under the competitive bidding route through two bidding frameworks:

- **Case I Bidding framework/DBFOO:** In 2007, the Union MoP had notified standard bidding guidelines for the procurement of power at competitive rates through Case I/ Case II routes. Under the Case I route, the bidders were free to choose any power generation technology, location, type and source of fuel. In 2013, the MoP revised the Standard Bidding Documents according to which the projects, in Case-I bidding would be awarded under the Design-Build-Finance-Own-Operate (DBFOO) model. Under the DBFOO bidding framework, the thermal power generation company is free to choose the source of fuel and is also responsible for acquiring land, procuring statutory clearances and securing fuel linkages and making arrangements for fuel transportation, handling and storage.
- **Case II Bidding Framework/DBFOT:** Case II bidding framework is location and fuel specific bidding i.e. the procurer specifies the location and/or fuel for the plant. The procurer is also responsible for arranging the fuel. These projects were developed on a Build-Own-Operate-Maintain (BOOM) basis. Under this framework, procurers (mostly state government-owned distribution utilities) and/or government support the bidders with regards to obtaining statutory clearances from the Ministry of Environment and Forests (MOEF), securing water linkages and fuel linkages. In 2013, the Case-II Framework for thermal power stations was revised to the Design-Build-Finance-Operate-Transfer (DBFOT) model. However the process was annulled subsequently and the MoP is presently reviewing the guidelines and model bidding documents.

Tariff for DBFOO Projects

Under this bidding framework, the tariff quoted by the bidders includes capacity and energy charges for the first year and is adjusted based on the framework provided in PPA for rest of the contract period.

Fixed Charge: The bidder quotes the fixed charge for the first accounting year, which depends on various components such as O&M expenses, depreciation, finance charges etc. The fixed charge determined for the first year will be revised annually to reflect 30 per cent of the variation in a composite index comprising Wholesale Price Index (WPI) and Consumer Price Index (CPI) and annual reduction of two per cent in fixed charge to pass on the benefit of depreciated assets to the consumers.

Fuel Charge: Fuel charge is a pass through, subject to appropriate safeguards, which addresses a major risk faced by power producers due to the uncertainty relating to fuel prices over the medium-term and long-term. The framework for competitive bidding provides alternative formulations for determination of fuel costs depending on the source and pricing of fuel supplies. Four alternative sources of fuel viz. (i) concessional fuel from Coal India Limited (CIL), (ii) fuel from captive mines, (iii) fuel through imports; and (iv) fuel through imports from captive mines situated outside India; have been provided for in the bidding framework.

The tariff under competitive bidding is being determined for thermal power generating stations only as the Government of India has exempted all hydroelectric projects from the mandatory tariff based competitive bidding system till Dec 2022.

Maldives

In Maldives, power generation is primarily diesel based and is owned by the State-owned integrated power utility i.e. STELCO (State Electric Company) which undertakes the functions of generation and distribution of electricity. The generation tariff is bundled and recovered through consumer tariffs directly and a separate mechanism for determination of generation tariff is not available.

Nepal

In Nepal, power is generated from NEA-owned stations, procured from local IPPs and imported from India. Tariff determination under all three modes is summarised below:

Mode I - Purchase from NEA-owned Generation Stations

As the NEA is a vertically integrated power utility, the tariff for its generating units is bundled with the retail tariff charged by NEA to its consumers. The Electricity Tariff Fixation Commission (ETFC) reviews the tariff application for the fixation of retail electricity supply and other charges filed by the NEA. As per the Electricity Act 1992, tariff and other charges are fixed on the basis of the rate of depreciation, reasonable profit, mode of the operation of the plant, changes in consumer price index, royalty etc.

Mode II - Purchase from Independent Power Producers (IPPs)

The structure and mechanism of recovery of tariff for the plants owned by independent power producers with whom the NEA has entered into Power Purchase Agreements (PPAs) is as per the terms and conditions specified in their respective PPAs.

The Model PPA (for projects up to 100 MW) issued by the Government of Nepal specifies a single part seasonal tariff payable towards energy up to the quantum of contract energy that was generated from the project and supplied by the company to it in every month from the commercial operation date at the rate of NPR 4.80/kWh in the wet season and NPR 8.40/kWh in the dry season. This base price is further escalated at a fixed rate of three per cent over five periods as per the following Table.

Table 8: Generation Tariff under Model PPA issued by the Government of Nepal

Duration (Duration to be calculated assuming that the next month of Commercial Operation Date shall be the first month)	Dry Season (From Poush (Dec-Jan) to Chaitra (Mar-Apr) (NPR per unit)	Wet Season (From Baisakh (Apr-May) to Mang (Nov-Dec) (NPR per unit)
1st - 12th months	8.40	4.80
13th - 24th months	8.65	4.94
25th - 36th months	8.90	5.09
37th - 48th months	9.16	5.23
49th - 60th months	9.41	5.38
61st month - till the agreement period	9.66	5.52

Mode III- Purchase (import) from India

The tariff for import of long-term power from India is as per the negotiated tariff and other terms and conditions of bilateral treaties signed by Nepal and India. The tariff for short-term power is as per the tariff negotiated and other terms and conditions of the PPA between NEA and PTC India (erstwhile, Power Trading Corporation), which are detailed in a later section of this report.

Pakistan

Generation tariffs are determined on the basis of the following available routes for power procurement in Pakistan i.e. the regulated route determined by the regulatory authority of Pakistan or the competitive bidding route.

Mode I- Tariff through Regulated Route

NEPRA is the regulatory authority, which determines the tariff for electric power services in Pakistan. NEPRA determines electricity tariffs considering the principles of economic efficiency and service of quality as per the **Tariff Standards and Procedure Rules** 1998. In cases under long-term PPAs, the generation company's tariff is determined on a cost-plus basis. The tariff standards provide for a **two-part tariff structure** for generation utilities. Within the regulated regime, there are two approaches that may be adopted by a generation utility (IPP) for the purpose of tariff determination:

i. **Project specific tariff:** NEPRA determines the tariff for the generation utilities on the basis of guidelines issued for tariff determination

ii. **Upfront tariff:** NEPRA specifies technology specific generic tariff for the various types of projects (technology/fuel), which can be adopted by the generation utilities. The upfront tariff is announced on yearly basis.

Mode II - Tariff Through Competitive Bidding Route

The tariff may also be discovered through an open competitive bidding process based on approved bidding documents. There are two options available to the procurer for structuring the bidding process:

- Bidding for a tariff
- Offering an up-front benchmark tariff and bidders to quote a discount on the benchmark tariff.

Sri Lanka

Electricity production is the responsibility of the generation licensees or generators licensed by the Commission (PUCSL). The energy and capacity produced by the generators is purchased by the transmission licensee (Single Buyer). Prices for capacity and energy sold by the generators and purchased by the Single Buyer are defined in the PPAs, establishing commercial conditions for such sales and purchases. The generation tariff is determined on the basis of type of PPA in Sri Lanka. Details available are stated in the Table below.

Table 9: Types of PPA and Methodology Prevailing in Sri Lanka

Type of PPA	Computation methodology for tariff determination
PPA between Thermal Power plant of CEB and Transmission Licensee	• For CEB Thermal Generation, the CEB Generation Licensee shall establish, for each Generating Unit in each Generating Plant included in the Generation License, a PPA with a **minimum duration of 5 years** The price formula in such a PPA shall be a **two-part tariff**, comprising: i. **Capacity price**, aimed at recovering fixed costs associated with each Generating Unit, namely: 1. Debt service 2. Efficient O&M fixed costs 3. Costs of services provided by CEB Generation Headquarters Capacity prices stated in each CEB Generation PPA shall be indexed every six months, if relevant, considering a basket of indices affecting the debt portfolio associated with each Generating Unit (thermal) ii Energy price, aimed at recovering: 1. Fuel costs (including factoring of no load heat rate and incremental heat rate) 2. Efficient variable O&M cost 3. Start-up cost 4. Others as may deem needed
PPA between Hydroelectric Power plant of CEB and Transmission Licensee	• For CEB hydroelectric generation, the CEB Generation Licensee shall establish, for each Generating Plant included in the Generation License, a PPA **with a minimum duration of 5 years** • The price formula shall be a **one-part capacity** price, comprising: 1. Debt service 2. Efficient fixed O&M costs including any resource costs 3. Costs of services provided by CEB Generation Headquarters • Capacity prices stated in each CEB Generation PPA shall be indexed every 6 months, if relevant, considering a basket of indices affecting the debt portfolio associated with each Generating Unit (hydroelectric)
PPA between IPPs/SPPs and Transmission Licensee	• The PPAs with IPPs/ SPPs shall be the agreements signed between such Generating Plant and the Transmission Licensee

Table 10: Principle for Determination of Cost Component for Generation Tariff prevailing in Sri Lanka

Cost Component	Principle for determination to be followed
Debt service cost	• Debt service costs shall be consistent with the same concepts included in the audited accounts of the last financial year of the generation licensee. In cases where the costs are not divided between each generating unit, proportional allocation as per installed capacity shall be used
Fixed O&M cost	• Fixed O&M costs shall be consistent with the same concepts associated with the generating unit or generating plant (or allocated to each unit/plant) included in the audited accounts of the last financial year of the generation licensee. The Commission shall have the right of using independent expert opinion to approve or amend the proposed costs
Fuel Cost	• Fuel costs shall be determined based on: ▸ Actual heat rate of each generating unit, determined through tests conducted by a certified technical auditor ▸ Fuel prices as published by the Ceylon Petroleum Corporation, or other entity, with which the CEB generation licensee has entered into a Fuel Supply Agreement (FSA)
Variable O&M costs	• Variable O&M costs shall be consistent with the same concepts in the audited accounts of the last financial year of the generation licensee for each generating unit or generating plant (or allocated to each unit/plant). The Commission will have the right of using independent expert opinion to approve or amend the proposed costs
Re-powering or refurbishment costs	• Re-powering or refurbishment costs of existing generating units or generating plants have to be submitted to the Commission for approval in a special filing process, initiated by the generation licensee. In case the Commission approves the cost and the appropriateness of the investment, the Commission will recalculate the capacity price for the remaining duration of the corresponding CEB Generation PPA
Start up costs	• Start up costs shall be in accordance with the PPA
Extraordinary maintenance costs	Extraordinary maintenance costs not included in the fixed or variable O&M costs have to be submitted to the Commission for approval in a special filing process, initiated by the generation licensee. In case the Commission approves the cost and the need for the investment, the Commission will recalculate the capacity price for the remaining duration of the corresponding CEB Generation PPA

The capacity price is indexed every six months considering a basket of indices. This helps to determine more realistic tariffs for the generation companies. Fuel cost which is a major component in generation is also calculated on the basis of actual heat rate or fuel rates published by Ceylon Petroleum Corporation, which is a more realistic approach for calculation of generation tariff. The tariff structure and principles for determination of its components are more on actual basis than a specific benchmark or standards.

5.2 Transmission tariff determination framework in various South Asian Regions

The following Table provides a comparison of different tariff determination principles / methodology adopted for transmission utilities by the countries within the SA region.

Table 11: Comparison of Principles/Approach for Transmission Tariff within SACs

Country	Regulated Tariff	Competitive bid/ TSA & RSA based tariff	Components of Tariff	Mode of Recovery
Afghanistan	No separate mechanism for transmission tariff determination/ recovery; Bundled with retail tariff			
Bangladesh	Yes (PGCB)	_	_	Wheeling charge of BDT 0.2791 per kWh
Bhutan	No separate mechanism for transmission tariff determination/ recovery; Bundled with retail tariff			
India	Yes (Annual Revenue Requirement & Multi Year Tariff framework)	Yes (BOOM / DBFOT)	Return on Equity, Interest and Finance Charges, O&M cost, Depreciation, Interest on Working Capital, Statutory Taxes, Incentives / Penalties	Annual Fixed Charges are recoverable on the basis of **Point of Connection Charges (PoC)** mechanism for use of Inter-State Transmission System (ISTS). **Wheeling Charges** (INR/ kWh) also payable to State Transmission Utility (STU) for use of Intra-State Transmission System (I-ISTS)
Maldives	No separate mechanism for transmission tariff determination/ recovery; Bundled with retail tariff			
Nepal	Yes (Tariff for NEA transmission function is bundled with retail tariff and determined by ETFC)	Yes (Model PPA provides for levy of a **"wheeling charge"** to be paid by the user to NEA for use of NEA's network to supply electric power generated by Independent Power Producers (IPPs) to third parties)	_	Single Part Tariff known as "wheeling charges"
Pakistan	Yes (based on MYT principles)	_	_	Single Part 'transmission charge' or 'use of system charge'
Sri Lanka	Yes	_	Capex allowance, Depreciation Allowance, Return on Assets, Operating Expenses, Taxes, Large Infrastructure Development Allowances	Transmission System Allowed Revenue is collected in form of a **Transmission Tariff** determined using the **Postage Stamp Methodology** in which Transmission System Allowed Revenue is allocated among beneficiaries in proportion to their demand at time of the System Monthly Peak Demand (Coincident Peak)

The following sub sections details the 'as-is' scenario of the process followed for determination of tariff for transmission utilities in each of the countries in the SA region:

Afghanistan

In Afghanistan, currently there is no separate mechanism for determination of transmission tariff. As such the tariff for the transmission function or use of transmission assets is bundled with the retail tariff charged to end consumers.

Bangladesh

The Power Grid Company of Bangladesh (PGCB) is the national grid operator in the country. It recovers its costs through wheeling charges levied from distribution utilities. Wheeling charges are set by the government through executive orders. The PGCB levies a **wheeling charge of BDT 0.2791 per kWh** (September 2015), which has been changed recently after seven to eight years.

Bhutan

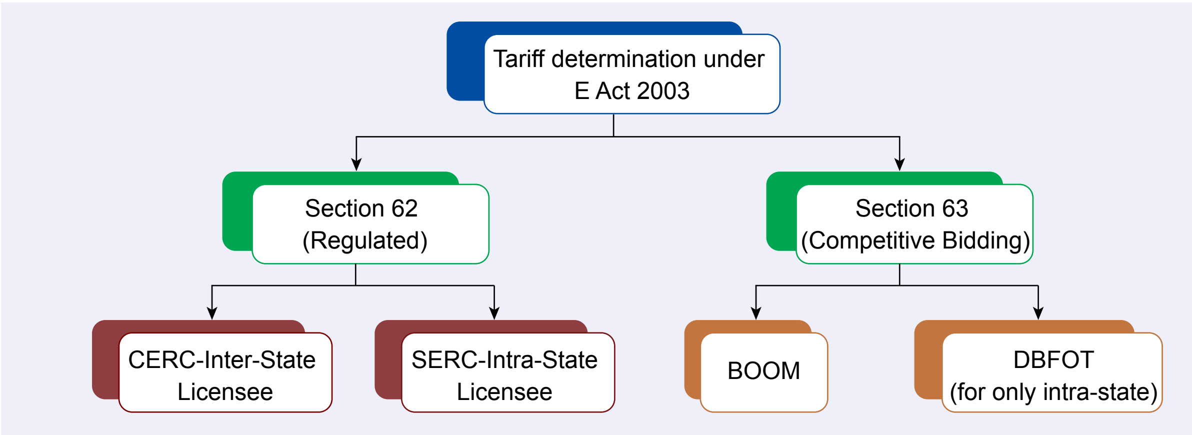
In Bhutan, currently there is no separate mechanism for determination of transmission tariff. As such the tariff for the transmission function or use of transmission assets is bundled with the retail tariff charged to end consumers.

India

The Indian Electricity Act 2003 provides for two modes for **tariff determination for transmission licensees**. The first mode is the 'regulated route' under Section 62 of the Act. Under this mode, the tariff for injection, wheeling and drawl of power is determined by the Appropriate Commission (CERC/SERC) on the basis of principles specified under the Tariff Regulations and this approved tariff is adopted by the distribution licensee (s). The second mode for transmission tariff determination is by way of '**competitive bidding**[4] wherein the tariff is discovered through a transparent competitive bid process, which is run as per the guidelines issued for this purpose by the Central Government under Section 63 of the Act.

4 The Tariff Policy 2006 mandated awarding of all transmission projects through competitive bidding process post 5 January 2011. However, there are exceptions to the above mandate which include i) those works that need to be completed in a compressed time schedule or under an exigency, where in such cases the CTU can offer those projects on a nomination basis; ii) projects for which BPTA(s)/TSA(s) were signed before 5 January 2011 and iii) projects involving Up-gradation/strengthening of already existing transmission lines and associated sub-stations.

Figure 5: India Tariff Determination Route



Mode I- Tariff setting under the regulated route

Transmission is a licensed activity in India where the CERC has the authority to issue licenses to persons to function as inter-state transmission licensees. The CERC is also responsible for regulating and determining the transmission tariff/charge for inter-state transmission system (ISTS) while the SERCs are responsible for determining the tariff/charge for intra-state transmission system (I-ISTS).

As in the case of transmission utility, the CERC and the SERCs have adopted a building block approach to determine the revenue requirement of transmission licensees which comprises of financial as well as operational parameters as summarised in Annexure-2.

Incentive and Penalty Framework

The incentive / penalty framework is restricted to the 'controllable parameters' as defined in the Tariff Regulations. Under the prevailing tariff framework (i.e. the CERC Tariff Regulations, 2014), the incentive / penalty framework covers the following parameters:

- Additional RoE is allowed if the transmission element is commissioned within the timelines specified in the Regulations
- Incentives are linked to actual Transmission System Availability Factor for the Month (TAFM) against specified NATAF. The incentives are built into the recovery of the AFCs.

In addition to these incentives/penalties, the financial gains earned by a transmission licensee on account of controllable parameters are shared between the transmission licensee and the users on a monthly basis with annual reconciliation. The financial gains are shared in the ratio of 60:40 between the transmission licensee and the users.

Billing and Payment of Charges

The transmission charge payable for a calendar month for the transmission system or part thereof is based on the approved AFCs for the transmission element. The recovery of AFCs is linked to the operating performance of the transmission licensee as summarised in the following Table.

Table 12: Computation of Transmission Charge

TAFM	Transmission Charge
(i) For AC System	
TAFM< 98%	AFC × (NDM/NDY) × (TAFM/98%);
98% < TAFM < 98.5%	AFC × (NDM/NDY) × (1);
98.5% < TAFM < 99.75%	AFC × (NDM/NDY) × (TAFM/98.5%)
TAFM > 99.75%	AFC × (NDM/NDY) × (99.75%/98.5%)
(ii) For HVDC bi-pole links and HVDC back-to-back Stations	
TAFM< 95%	AFC × (NDM/NDY) × (TAFM/95%);
95% < TAFM < 96%	AFC × (NDM/NDY) × (1);
96% < TAFM < 99.75%	AFC × (NDM/NDY) × (TAFM/96%)
TAFM > 99.75%	AFC × (NDM/NDY) × (99.75%/96%)

Where,

- TAFM is Transmission System Availability Factor for the month, in percentage
- AFC is Annual Fixed Cost specified for the year, in INR
- NDM is Number of days in the month
- NDY is Number of days in the year
- NATAF is Normative Annual Transmission Availability Factor, in percentage

The billing and payment of the charges is carried out in accordance with the procedures specified under the CERC (Sharing of Inter-State Transmission Charges and Losses) Regulations, 2010.

Mode II - Tariff Discovery Through the Competitive Bidding Framework

The tariff for transmission elements can also be discovered through tariff-based competitive bidding as provided for under Section 63 of the Electricity Act 2003. Tariff-based competitive bidding in the transmission sector in India is currently undertaken using one of the following models:

- BOOM Model
- DBFOT Model

The key features of these models are summarised in the following Table.

Table 13: Competitive Bidding Framework for Transmission Utilities

Features	BOOM Model	DBFOT Model (for only intra-state)
Ownership of capital assets	Private sector	**Private player during contract.** **After contract, asset transferred back to STU**
Responsibility of capital investment	Green field investments by Private sector	**Green field investments by private sector with VGF funding**
Duration of the contract	35 years	**25 years + 10 years**
Process managed by	BPC (REC and PFC) appointed by GoI	**Concerned state authority (STU)**
Project development	All consents, clearances and permits are obtained by the developer	**Consents, clearances and permits are obtained by the authority apart from Line ROW**

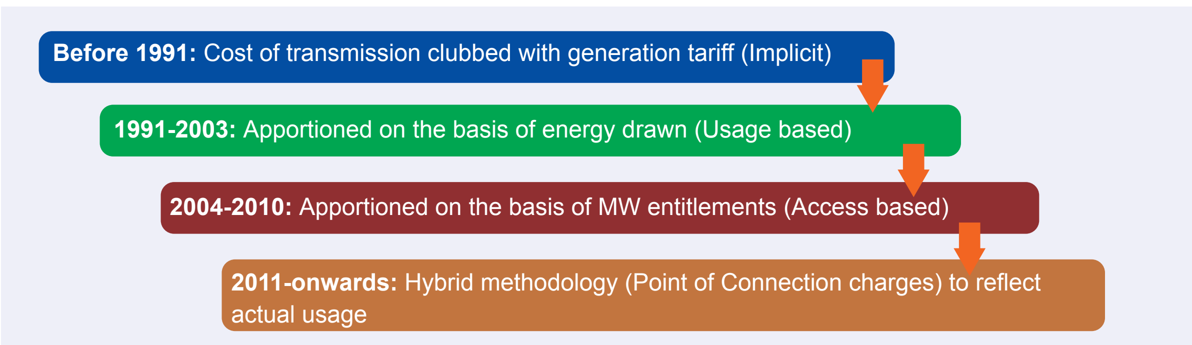
Under the competitive bidding route, the bidder quotes the transmission charges which have two components, namely i) escalable transmission charges which shall be escalated at rates notified by CERC; and ii) Non-escalable transmission charges. The escalable component cannot be more than 15 per cent of the non-escalable component. The bidder can quote different annual tariffs for various years within a specified variation band.

Levellised tariffs: The tariffs quoted by the bidders are discounted at a rate specified by the CERC to arrive at a single figure of levellised tariff and the project/bid is awarded to the bidder with the lowest levellised tariff.

Sharing of Transmission Charges Using Point of Connection (PoC) Methodology

The recovery and sharing of transmission tariff has evolved from being bundled with the generation tariff in the past to being sensitive to distance, direction and quantum of usage at present. The following chart summarises the evolution of mechanism for charging transmission tariff in India.

Figure 6: Evolution of charging methodology for transmission charges



Since 2011, India has moved to simplified nodal pricing - PoC methodology. The PoC methodology is used for computation and sharing of the ISTS charges and losses among Designated ISTS Customers (DICs). The PoC charge depends on the quantum of the power flow and location of the node (injection/drawl) in the grid and is sensitive to distance and direction. The PoC charge is computed for each node of DICs based on hybrid method, which employs both - average participation method and marginal participation method. The PoC charge is independent of contract "path".

It is transparent as all data used for computing the charges is shared with users; the transmission charge payable for any contract is known upfront and hence it can be considered while entering into a contract.

Maldives

Currently there is no separate mechanism for determination of transmission tariff in Maldives. As such the tariff for the transmission function or use of transmission assets is bundled with the retail tariff charged to end consumers.

Nepal

As the NEA is a vertically integrated power utility, the tariff for wheeling of power on its transmission network is bundled with the retail tariff NEA charges its customers. The Electricity Tariff Fixation Commission (ETFC) reviews the tariff application for the fixation of electricity and other charges filed by the NEA. As per the Electricity Act 1992, tariff and other charges are fixed on the basis of the rate of depreciation, reasonable profit, mode of the operation of the plant, changes in consumer's price index, royalty etc.

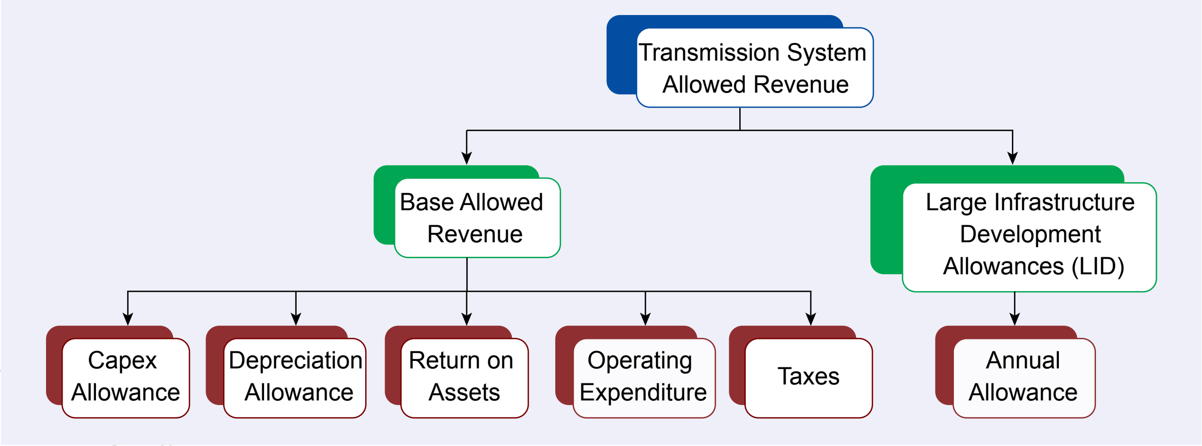
Pakistan

The **National Power Tariff and Subsidy Policy Guidelines**, 2014 provide the basis of the regulatory framework for determination of transmission charges levied by the transmission licensee (NTDC). A 'transmission charge' or 'use of system charge' based on Multi Year Tariff Principles has to be approved by the NEPRA from FY 2015-16.

Sri Lanka

In Sri Lanka, the transmission licensee is allowed to recover the Transmission System Allowed Revenue (TSAR), which is the revenue that the transmission licensee is allowed to collect from the transmission users for the use of the transmission system. Tariff methodology is approved by the Public Utilities Commission of Sri Lanka (PUCSL) in accordance with Section 30 of the Sri Lanka Electricity Act 2009.

Figure 7: Transmission System Allowed Revenue Component



The base allowed revenue shall be determined for a tariff period and components detailing is mentioned in Annexure-2. The TSAR shall be calculated based on a **forecast cash flow discounted at the Allowed Rate of Return on Capital** for the tariff period, considering following factors:

- Initial Regulatory Asset Base (RAB) (the value of the assets belonging to the licensee to provide the transmission service, excluding connection assets).
- Rolling forward of the initial RAB, considering minor Capital Expenditure (CAPEX) for the period
- Depreciation of existing non-depreciated assets

- Return on assets
- Efficient operational expenditure (OPEX)
- Taxes

Transmission System Allowed Revenue shall be collected in the form of a transmission tariff, only from Distribution Licensees and Transmission (Bulk Supply) Customers. The transmission tariff shall be determined using the **Postage Stamp Methodology** in which the TSAR is allocated among Distribution Licensees and Transmission (Bulk Supply) Customers in proportion to their demand at the time of the System Monthly Peak Demand (Coincident Peak).

5.3 Current Practices related to Tariff in SA Cross Border Electricity Trade

Presently, cross-border power transactions exist between India-Bangladesh, Bhutan-India and India-Nepal. The respective transmission and tariff framework in existing CBET in the SA region has been summarised below in Table 14 and Table 15.

Table 14: Existing Cross Border Electricity Trade Generation Tariff Structure in South Asia

	Bhutan-India	India-Bangladesh	India-Nepal
Tariff structure	Both Tala and Dagachhu PPAs have single-part tariff structure.	Both NVVNL and PTC PPAs have a two-part tariff structure comprising of Fixed Charge and Variable Charge.	Both Treaty/Bilateral arrangement and PTC PPA have single-part tariff structure.
Tariff recovery by generator	The tariff is payable on actual metered energy at delivery point.	The Fixed Charge is payable on Declared Capacity and Variable Charge is payable on Scheduled Energy	The tariff is payable on actual metered energy at delivery points in treaty/bilateral arrangement. However, in case of PTC PPA tariff is payable on scheduled energy at delivery points
Principle of determination	The tariff for both Tala and Dagachhu PPAs was determined on a negotiated basis	The tariff for NVVNL PPA is as per CERC regulations (agreed based on negotiation). On the other hand, tariff for PTC PPA was determined through competitive bidding	The tariff in both treaty/ bilateral arrangement and PTC PPA was agreed based negotiation
Tariff and escalation	The tariff for Tala PPA is 1.80 INR/ kWh for 1st year (COD achieved in 2006-07) and currently it is 1.98 INR/ kWh. There is a 10% escalation for every 5 years till loan repayment is complete and subsequently, 5% escalation for every 5 years. The tariff for Dagachhu PPA is 2.98 INR/kWh for 1st year and its operations started in 2015. There is a 2% escalation per year till 15 years and subsequently, escalation to be decided based on mutual discussions.	The tariff for NVVNL PPA was in the range of 2.10-2.86 INR/kWh during Aug '14-Feb '16 period. As discussed earlier, tariff is as determined by CERC. The tariff for PTC PPA was in the range of 4.26-5.08 INR/kWh during Dec '13-Feb '16 period. No escalation in tariff in this PPA.	The prevailing tariff in Treaty/Bilateral arrangement is 5.40 INR/kWh. In case of PTC PPA tariff was 4.55, 4.35, 4.30, 3.75 INR/kWh during FY11-FY14 (contract period earlier mentioned)

Tariff structure: There are two-parts in transmission tariff viz. Escalable Transmission Charges and Non-Escalable Transmission Charges, determined through competitive bidding. The quoted first year Escalable Transmission Charges are adjusted by the index published by CERC based on WPI and CPI (IW) on a semi-annual basis. The Non-Escalable Transmission Charges remain fixed for all 35 years as quoted by the bidder

Practices in South Asia CBET

	Bhutan-India	India-Bangladesh	India-Nepal
Term	The TSA term is 25 years from CoD	The TSA term is 35 years from CoD	The TSA term is 25 years from CoD
Tariff structure	POWERGRID to pay POWERLINKS transmission tariff determined as per prevailing CERC regulations	BPDB to pay POWERGRID transmission tariff determined as per prevailing CERC regulations	The basis of transmission tariff for Nepal part: RoE, Interest on loan, Depreciation, Interest on Working Capital, O&M expenses The basis of transmission tariff for India: Tariff to be determined by CERC as per prevailing regulations
Principle of tariff determination	The transmission tariff is as per CERC regulations	The transmission is as per CERC regulations (agreed based on negotiation)	The transmission as mentioned above (agreed based on negotiation)
Tariff recovery	The transmission tariff to be paid on System Availability (normative availability of 98%)	The transmission tariff to be paid on System Availability	The transmission tariff to be paid on System Availability

5.4 Recommendations for Generation and Transmission Tariffs for CBET in South Asian Region

Generation Tariff Structure:

For long-term and medium-term power supply agreements, it is recommended that the tariff structure be adopted in line with the prevailing practice in each SAC and existing CBET agreements in the SA region. **A two-part tariff structure for thermal generators and single-part tariff structure for hydro generators is recommended for the long and medium term.**

Typically, short-term power supply contracts stipulate the energy (in MU or MW & hours) to be transacted with a provision of variation to a certain percentage, say +/-20% in scheduled delivery. **A single part tariff is recommended for the short term. This is in line with the prevailing practice in short-term PPAs within India and short-term CBETs between India-Nepal**.

Tariff Recovery by Generator:

In case of single-part tariff as in the case of short-term thermal power and hydro power tariff shall be recovered based on scheduled energy at the delivery point. Also, failure to off-take power by buyer shall be treated as deemed delivery for payment of delivery charges.

In case of two-part tariff applicable to thermal power generation based on long and medium term PPAs fixed charge shall be recovered based on declared capacity (linked with declared capacity and pre-defined normative availability factor) and variable charge shall be recovered based on scheduled energy at delivery point. Variable charge recovery is based on schedule energy regardless of actual generation or drawl.

In case of CBET within the SA region, delivery points are likely to be boundary points with India due to geographical region. Hence, **it is recommended that all cross-border transactions will be subject to Indian DSM at such boundary points**.

Principle of Tariff Determination for Generator:

There are broadly two options for tariff determination viz. competitive bidding or cost-plus/ negotiated (either through regulatory mechanism such as CERC tariff principles or based on some other tariff principles).

India is one of the major demand centres in the SA region and power procurement by distribution utilities in India is through mandatory competitive bidding with a few exceptions for eg., procurement from hydro stations is exempt till FY2022. On the other hand, the supply from Nepal and Bhutan would be pre-dominantly hydro based and typically, hydro projects entail several issues like high capital investment, technical such as geology and hydrology, environmental and social and have long gestation periods. **Therefore, given the nature of the risks and the prevailing scenario, it is recommended that procurement from hydro be on a cost-plus/negotiated basis for both medium-term and long-term contracts. For short-term contracts a single part tariff is more apt in this case and also it is as per prevailing practices in short-term PPAs.**

On the other hand, procurement from a thermal project can be on a competitive bidding basis. As discussed above, competitive bidding is mandatory in India for power procurement by distribution utilities. Further, competitive bidding has already been adopted by Bangladesh for procurement of 250 MW from India for a three year term. Further, Bangladesh has also taken steps to procure additional power through competitive bidding.

Therefore, it is recommended that procurement from thermal projects be based on a competitive bidding basis for both medium-term and long-term contracts. In case of short-term contracts, buyers may adopt the competitive bidding route or negotiation (cost-plus) route for tariff determination based on pre-agreed criteria.

Tariff escalations for generation: The provision of tariff escalation is widely varying in the PPAs reviewed like fixed escalation every year or fixed escalation after a block of years or linked to respective country indices. Also, the approach is different for thermal generators and hydro generators.

Ideally, the escalation on the tariff is allowed to compensate for future events beyond the control of the seller such as change in prices of raw materials or other goods, services, taxes and other levies and currency variations over a period which would have an impact on overall tariff. Therefore, **it is recommended that the tariff escalation mechanism shall be included in medium-term and long-term contracts**. The exact value and mechanisms of escalation shall be decided along with tariff determination in case of hydro projects and shall be specified by the buyer prior to competitive bidding in case of thermal projects.

In the case of short-term contracts, it is recommended that the tariff shall be fixed during the contract period due to shorter duration of contracts as the probability and impact of future events is expected to be low or moderate.

Further, some of the SACs such as Nepal, Sri Lanka, Afghanistan and Maldives have a vertically integrated power industry structure; while Bangladesh and Bhutan have a partially unbundled structure i.e. separate transmission and generation utilities, respectively. In such cases, the tariff for generation and transmission is also bundled together and recovered directly from end beneficiaries/ consumers. In order to move towards a broadly uniform regulatory framework and facilitating CBET, we recommend the promotion of CBET and a clear indication of generation and transmission costs, each SAC may determine tariffs with **separate components of power generation costs and transmission costs**. This would also assist in comparing power generation tariff within the country and cross-border imports. Further in case separate transmission charges/ costs are available, it would help in computing open access charges for using the transmission network for the purposes of CBET.

Transmission Pricing

A transmission pricing framework is essential for allocating transmission related costs to various entities utilising the transmission system. The transmission pricing framework varies among SACs. It is bundled with retail tariff in Afghanistan, Bhutan and Nepal. The mechanism for recovery of transmission tariff is based on per unit, per MW and postage stamp in Bangladesh, Pakistan and Sri Lanka respectively. In India, transmission price recovery is through the PoC mechanism.

In the absence of a transmission pricing framework, it would be challenging to allow generators or consumers connected to the transmission system in each SAC to sell or buy power from other SACs. Hence, to promote CBET there should be an established transmission pricing framework. The transmission pricing framework comprises of two market aspects viz. determination of total transmission charges (to be carried out by respective Regulators or Authorities) and sharing of such charges among various users of such a transmission system. Given below are five popular options for sharing transmission charges.

- **Postage Stamp:** Summing-up all transmission costs and allocating them a usage (uniform charges) based on demand or energy drawl (per MW or per unit). This could be modified to Zonal Postage Stamp wherein, specific zones (region, state, discoms etc.) are created and the transmission charge in a particular zone is calculated by accounting the assets in that zone based on demand or energy drawl related to that zone.
- **Contract Path:** Defined fictitious contract path for a transaction (from source to sink) and allocate the costs of transmission elements on the path.
- **Distance based MW-Mile:** Charges are applied to a user based on a beeline distance between injection and receipt points and magnitude of transmitted power.
- **Power Flow based MW-Mile:** Allocate charges of each transmission element to a transaction based on the extent of use of that element by the transaction. Charges are determined as a function of magnitude, path and distance travelled by the transacted power.
- **Point of Connection (PoC):** The methodology takes into consideration location and is sensitive to distance and direction of the node in grid. The PoC methodology adopted in

India is a hybrid of average participation method and marginal participation method. Average participation method is based on proportionate tracing of electricity from generator node to demand node or vice versa. Marginal participation method analyses how the flows in the grid are changed when incremental changes are introduced in generation or consumption at each node.

The following Table shows a comparison of these methods across key parameters.

Tab[illegible]5: Transmission Pricing - Comparison of Methods

Parameter	Postage Stamp	Contract Path	Distance based MW-Mile	Power flow based MW-Mile	Point of Connection
Allocative efficiency	Low	Medium	Medium	High	High
Distance sensitivity	NA	√	√	√	√
Directional sensitivity	NA	NA	NA	√	√
Complexity	Low	Medium	Medium	High	High

It would be challenging to adopt uniform methodology across SACs for transmission pricing related to cross-border trades given the differences in industry structure, regulatory mechanisms, etc. Hence, a segmented approach needs to be adopted viz. the transmission pricing for each link in the overall path needs to be separately determined.

In the near future, it is envisaged that cross-border transactions among SACs are likely to be through India by virtue of its geographical position. Hence, the transmission pricing in India can be adopted for the Indian part in the chain of transaction.

For the rest of the chain, the transmission pricing mechanism should be recommended to promote CBET. This is because the powers and sellers imbedded in any particular nation's grid shall be affected by the transmission pricing mechanism of that nation. As discussed above, there are various methodologies for transmission pricing but they vary in allocative efficiency and complexity of implementation. **Hence it is recommended for the transmission system within a country, the transmission pricing of that nation shall be applicable**. It is noted that some of the nations do not have a separate transmission tariff and the same is bundled with the generation tariff. **Hence it is recommended that the transmission tariff may be separately identified in case of bundled tariff**.

In certain nations the transmission tariff is available but the methodology of determination of the same is not available in the public domain. Hence, keeping in mind the industry structure's status and regulatory mechanisms in each SAC, postage stamp methodology (per MW for long-term and medium-term transactions and per kWh for short-term transactions) could be adopted for transmission pricing in the absence of any pre-defined transmission pricing mechanism. In case of short-term transactions, trades can also be done for part of the day (say, different MW value in different hours/blocks) hence it would be more convenient to define the transmission charge in per kWh terms.

6 Transit Fee Framework for Transmission Service

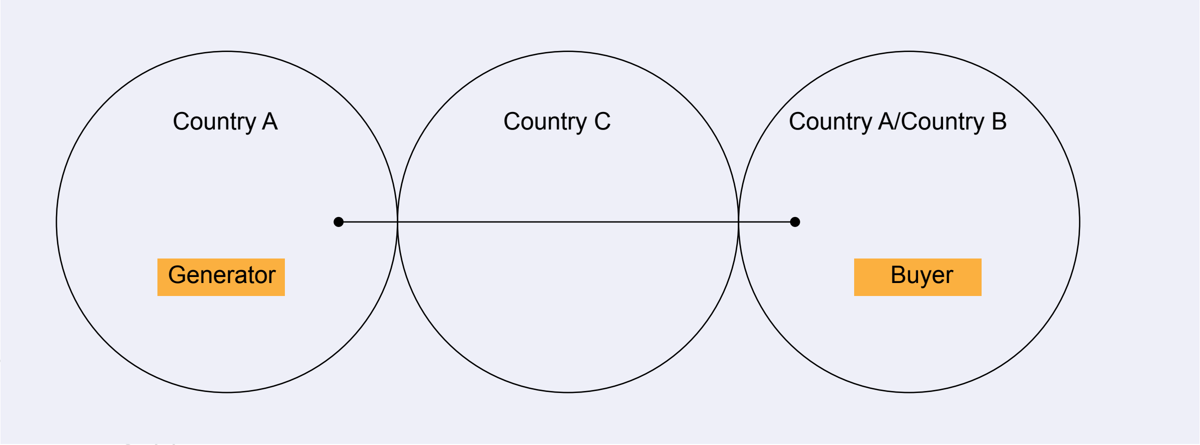
Introduction

Transit implies movement of goods produced in one country through the territory of another country to be consumed in a third country, as well as movement of goods from one point in a country to another point of the same country through the territory of another country. In case of electricity and power, transit of electricity and power can be defined as:

a. Transmission, via the territory of the Party through its power grids, of electricity and power generated within the territory of another nation and destined to the territory of a third nation and

b. Transmission of electricity or power between two points of one nation via the territory of another Party through its power grids.

As indicated below, the intermediary country (Country C) through which power transmission undertakes from the Country A (seller) either to a party (buyer) within its own country or another country (Country B), shall be entitled to charge a transit fee for electric energy transmitted through its system from the seller and/or buyer.



Electric energy transit is performed in accordance with transit agreements concluded between the economic entities - participants of trading operations with entity providing for the transit facility. Such agreements accompany agreements for supply (sale/purchase) of electric energy. The volumes and transit tariff is invariably based on the cost value of electricity transmission and transit charges or fees. The cost value of electricity transmission incorporates the transit distance, grid operation and maintenance charges and transit loss compensation.

International Case Studies

The following Table summarises some of the transit fee frameworks implemented in cross-border transmission systems.

Recommendation for Future Cases of South Asian CBET

Presently, electricity trade in the SA region is primarily a result of bilateral agreements between countries. At present, there is power trading between India-Nepal or India-Bangladesh or India-Bhutan. As per the policy guidelines issued by MoP, India, at present there is no provision of multi-lateral trades and these recommendations are based on the assumption that such trades will occur once suitable policy changes are made by the various SAC governments.

Parameter	Corridor / Pool					
	Belarus - Russia - Estonia - Latvia - Lithuania	Russia - Belarus	Central Asia - Southern Kazakhstan	EU Member Countries	CIS Member Countries	Kyrgyzstan -Tajikistan-Afghanistan-Pakistan (CASA 1000)
Document reference	BRELL Draft Methodology Guidelines for Electricity Transit Through the Electrical Ring "Belarus - Russia - Estonia - Latvia - Lithuania"	Draft Methodology for Calculating Tariff for Transit of Russian Electricity through Belarus Power Grids	Existing Methodology to Calculate Transit Volumes in the United Power System of Central Asia and Southern Kazakhstan	ETSO's/ ENTSO Existing ITC Model	Methodology for Calculating Fees for Electricity Transmission and Transit Services Within the Power Pool of CIS Member-States	CASA 1000 Agreement
Countries involved	Belarus, Russia, Estonia, Latvia, Lithuania	Republic of Belarus, third state, UES Russia	United Power System of Central Asia and Southern Kazakhstan Transit Nations: Kazakhstan, Kyrgyzstan and Uzbekistan	EU countries	Armenia, Belarus, Kazakhstan, Kyrgyzstan, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan	Kyrgyz Republic, Tajikistan, Afghanistan and Pakistan

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Summary of transit pricing approach	Russian block is subdivided into several balance-sheet blocks. A total compensation amount is determined for all balance-sheet blocks over the calendar month. C(compensation) = Total of {T(i)*K* C1} where, Ti = transit of electricity of the balance-sheet block over the calendar month, determined on an accrual basis by adding hourly values of electricity transit (in thousands kWh) K=K is the transit factor (to be determined in accordance with the multilateral electricity transit agreement entered into between settlement parties (relative units) C1=flat price for electricity set for one year (to be determined in accordance with the multilateral electricity transit agreement entered into between settlement block parties (€/thousand kWh)	The price for electricity transit is calculated on the basis of the share of semi-fixed costs of maintaining and operating the transmission network of the Republic of Belarus and the incremental losses of electricity incurred in the transmission network of the Republic of Belarus in connection with the transit of Russian electricity through the Belarus power grid. All allowances for tax as well as profit margin (rate of return) are also factored in while computing the transit charges.	Transit tariff includes the following: In-transit losses of electricity; Transit costs associated with electricity transit services, including operating and dispatch expenses, depreciation charges, etc.	The pricing is based on the primary principle that the Transmission Service Operators should be suitably compensated for the costs of making infrastructure available to host cross-border flows of electricity. An ITC (Inter Transmission Compensation) fund was created which shall provide compensation for the cost of losses incurred on national transmission system along with incremental cost of making infrastructure available for power flows. The transit fee shall be divided into two shares, one paid by exporter (up to 25%) and another, higher one paid by importer of energy (at least 75%)	The methodology applies that following approach to cost allocation: a. Dispatching of electricity transmission/ transit is calculated in proportion to the amounts of transmitted/transited electricity b. O&M expenses of the transmitters' network is calculated in proportion to transmission/ transit distances and amounts of transmitted/transited electricity c. Electricity loss compensation includes two components.	The Governments of Afghanistan and Pakistan negotiated and agreed upon a transit fee of 1.25 United States Cents per kWh (subject to annual indexation) for supply of Central Asian electricity to Pakistan through Afghan territory. This fee constitutes nearly 13% of the total costs / tariff.
Key components of transit pricing	• Hourly values of electricity transit, • Balance sheet block index, the transit factor, • Flat price for electricity set for one year, • Net power flow of the balance-sheet block over the calendar month	• Semi-fixed costs of maintaining and operating the transmission network, • Volume of Russian electricity transit, • Incremental losses of electricity incurred in the transmission network • Allowance for tax • Rate of return	• In-transit losses of electricity; • Cost on infrastructure and other transit costs including O&M expenses, depreciation charge etc.	• In-transit losses of electricity; • Cost of infrastructure and other transit costs including O&M expenses etc. • Transit factor, • Load factor • Framework Fund	• Quantum of transmitted/ transited electricity, • O&M expenses of transmitter's network • Transit distance • Electricity loss compensation	• Pricing based on mutual agreement between the governments; • Annual indexation of mutually agreed fees
Transit fee value (if any)	–	–	0.417 US Cents per 1 kWh per 1000 km of the conditionally dedicated transit network	–	–	1.25 US Cents per kWh

India, by virtue of its geographical position may also serve as an intermediary country for transfer of power say from Nepal / Bhutan to Bangladesh / Pakistan. Hence, a transit fee may be charged by India from the exporter viz. Nepal / Bhutan and/or the importer viz. Bangladesh / Pakistan. Similarly there is a likelihood of power from North-East of India to be injected in the Eastern Region of India where the Bangladesh grid may be used for transit.

Critical analysis of the transit fee frameworks adopted in various regions indicate that the transit frameworks have evolved from a simplified methodology of tariff based on cost value of electricity transmission and a transit profit margin to a more sophisticated methodology which incorporates corrective grid utilisation factor, transit distance and transit loss compensation. Based on the above, ENTSO-E's ITC model is being adopted by the regions worldwide as the most appropriate for calculating compensations relevant to cross-border flows.

In the context of South Asian CBET, the transit fee framework may be applied to enable the intermediary entity to recover the marginal costs related to electric energy transit. Therefore, the transit fee should broadly entail:

- The costs of making infrastructure available to host cross-border flows of electricity which may include the operations and maintenance expense of the infrastructure including periodic renovation, modernisation and upgradation activities to be undertaken by the intermediary country
- The costs of technical losses incurred on national transmission systems as a result of hosting cross-border flows of electricity;
- Profit margin of the host nation.

It is recommended that in the case of applicability in the future, the transit fee may be calculated as under:

Transit Fee = O&M Expenses + Cost of Losses + Profit Margin

Where O&M expense is related to the grid actually or notionally used and losses are those losses, which take place due to the transit of the wheeled power. Cost of losses may also be borne in kind by injecting additional power to compensate for the losses.

The profit margin can be linked with the normative returns associated with the usage of the infrastructure. However the profit margin may be restricted based on the extent of usage of the infrastructure.

Note: The above description is a high level guidance on the proposed framework for transit fee for transmission services. However, a detailed study should be commissioned to develop a recommended detailed framework and approach for transit fees for transmission services in the SA region.

7 Implementation of Recommendation

It is anticipated that that the recommendations shall be agreed upon by the various stakeholders in the SACs. These recommendations may be suitably modified as per the country's prevailing situation and future plans, however in the future an implementation plan can be accorded to these recommendations through a structured framework and with the consent of all stakeholders. The following approach is proposed in order to ensure the implementation of the recommendations in the long run:

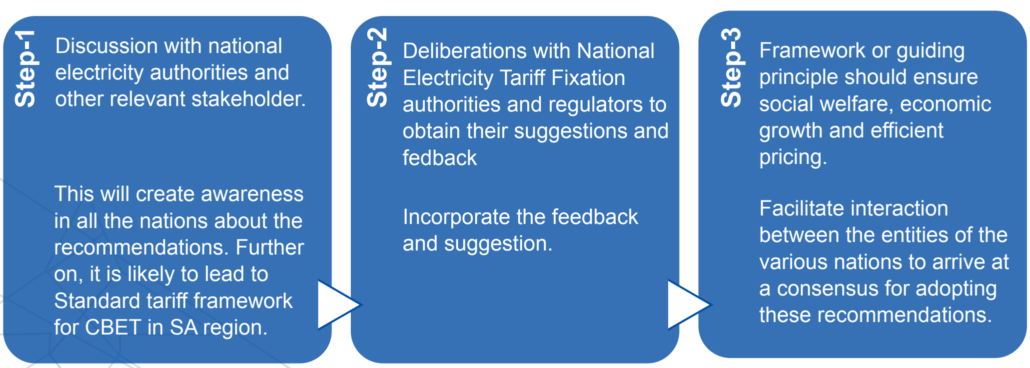
STEP 1: The recommendations to be disseminated to all stakeholders especially the national electricity authorities and power ministries of the SACs.

STEP 2:

a. Deliberations with National Electricity Tariff Fixation authorities and regulators to obtain their suggestions and feedback.
b. Incorporation of the feedback and suggestions received to fine tune the recommendations. Additional studies/reviews may need to be undertaken for further detailing of the recommendations.

STEP 3: Facilitate interaction between the entities of the various nations to arrive at a consensus for adopting these recommendations (in modified form if required) for cross-border trade transactions. The overall process is illustrated in Figure 8.

Figure 8: Implementation Process of Recommendation



The above steps will require consensus building and hence, will need to be facilitated through a respective institution of SACs. The study proposes that SA regional, sub-regional forum/bodies manage this process in close coordination with various country level electricity authorities/ decision makers/Committees etc.

Annexure 1: Components of ARR for Generation Utility in India

Component of ARR	Computation Methodology
Financial Parameters	
Return on Equity (RoE)	• Tariff guidelines provide for return on normative equity computed at a base rate of 15.5% grossed up with effective tax rate • An additional return of 0.5% allowed in case of new thermal generating station if capital works are completed within specified timelines • Normative Equity: For new thermal generating stations (COD on or after 01.04.2014): If actual equity is more than 30% of capital costs, then normative equity is restricted to 30% of capital cost; while in case the actual equity is less than 30% of capital cost, then normative equity is considered to be actual equity deployed; For existing thermal generating stations (COD before 01.04.2014): Debt-equity ratio allowed by the Commission for determination of tariff for the period ending 31.3.2014 will be considered.
Interest on Loan	• Tariff guidelines provide for interest on normative loan computed on weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the project • Normative loan is the balance capital cost after reducing normative equity @ 30% or less (in case actual equity is less than 30%) from the admitted capital cost • Deemed repayments for the year shall be equal to the depreciation allowed for that year, notwithstanding any moratorium period availed by the generating company • The interest on loan is calculated on the normative average loan of the year by applying the weighted average rate of interest
Depreciation	• Depreciation is charged up to a maximum of 90% of admitted capital cost of assets, while 10% of admitted capital cost of assets is considered as residual value • Depreciation calculated annually based on the Straight Line Method (SLM) at rates specified by CERC
Interest on Working Capital	• For purposes of tariff determination for thermal generating stations, CERC guidelines define working capital as: ‣ Cost of primary fuel (coal /lignite/ limestone) for 15 days for pithead stations & 30 days for non-pit-head stations; ‣ Cost of secondary fuel oil for 2 months; ‣ O&M expenses for 1 month; ‣ Maintenance spares @ 20% of O&M expenses (for thermal) and 15% of O&M expenses (for hydro); and Receivables equivalent to 2 months • Cost of fuel is based on landed cost incurred (taking into account normative transit and handling losses) by the generating company and calorific value of the fuel • Interest on working capital is taken as interest rate of State Bank of India as on 1st April of the year the station is declared under commercial operation

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Annexure 1 Cont...

Component of ARR	Computation Methodology
O&M expenses	• O&M expenses refer to expenditure on employee, repair & maintenance and administrative & general expenses • CERC provides normative O&M expenses (INR per MW) for the purpose of tariff determination
Operating Norms **Operating Parameters**	• CERC has defined operating norms for Normative Annual Plant Availability Factor (NAPAF), Gross Station Heat Rate (GSHR), Secondary Fuel Oil Consumption (SFOC) and Auxiliary Energy Consumption (AEC) for the generating stations

Annexure 2: Components of ARR for Central Transmission Utility, India

Component of ARR	Computation Methodology
Return on Equity (RoE)	• Tariff guidelines provide for return on normative equity computed on at a base rate of 15.5% grossed up with the effective tax rate • An additional return of 0.5% allowed if any element of the transmission project is completed within the specified timeline and it is certified by the Regional Power Committee/National Power Committee that commissioning of the particular element will benefit the system operation in the regional/national grid
Interest on Loan	• CERC guidelines provide for interest on normative loan computed on weighted average rate of interest calculated on the basis of the actual loan portfolio at the beginning of each year applicable to the project • Normative loan is the balance capital cost after reducing normative equity @ 30% or less (in case actual equity is less than 30%) from the admitted capital cost • Deemed repayments for the year shall be equal to the depreciation allowed for that year, notwithstanding any moratorium period availed by the generating company • The interest on loan is calculated on the normative average loan of the year by applying the weighted average rate of interest
Depreciation	• Depreciation is charged up to a maximum of 90% of admitted capital cost of assets, while 10% of admitted capital cost of assets is considered as residual value • Depreciation calculated annually based on the Straight Line Method (SLM) at rates specified by CERC
Interest on Working Capital	• For purposes of tariff determination for thermal generating stations, CERC guidelines define working capital as: ‣ O&M expenses for 1 month; ‣ Maintenance spares @ 15% of O&M expenses; ‣ Receivables equivalent to 2 months of fixed cost • Interest on working capital is taken as interest rate of State Bank of India as on 1st April of the year the station is declared under commercial operation
O&M expenses	• O&M expenses refer to expenditure on employees, repair & maintenance & administrative & general expenses • CERC provides normative O&M expenses viz. INR per bay for sub-stations and INR per ckt km for transmission lines for the purpose of tariff determination
Operating Norms	
Operating Parameters	• CERC has defined operating norms for Normative Annual Transmission System Availability Factor (NATAF) and auxiliary energy consumption in a sub-station for the transmission utilities.

Annexure 3: Tariff Principles for Components of "Base Allowed Revenue"- Sri Lanka

Cost Component	Principle/Methodology Specified in the Regulations
Depreciation Allowance	• Depreciation shall be calculated on the straight-line method and the depreciation rates shall be those that are currently used in the statutory accounts. Once an asset is fully depreciated, it shall be removed from the gross value of the assets.
Return on Assets	• This return shall reflect the actual cost of debt of the Licensee and a positive return on equity based on the cost of the long-term debt of the Government of Sri Lanka. The rate of return on equity will be defined by the Commission for each tariff period. The rate of return on assets shall be calculated considering a weighted average of the cost of debt and equity, employing the actual debt to asset ratio. The rate of return on assets shall be defined by the Commission for each tariff period.
Capex Allowance	• The Forecast CAPEX program for the Transmission Licensee shall be the Long-term Transmission Development Plan (LTTDP) approved by Commission for the next 5 years. Investments stated in the LTTDP shall be separated into Minor CAPEX and Large CAPEX where, ‣ Minor CAPEX means all replacement, reinforcement and quality-driven investments approved by the Commission. The Transmission Licensee shall present its minor CAPEX development plan and the criteria followed in establishing the minor CAPEX development plan. Non-load related CAPEX shall be included in minor CAPEX. ‣ Large CAPEX, including all the investments related to the expansion of the transmission system. • Only minor CAPEX shall be included in the rolling forward of the RAB (regulatory asset base) according to the CAPEX program developed by the transmission licensee and approved by the Commission.
Operating Expenditure	• The OPEX to be included in the calculation of the Transmission Base Allowed Revenue shall be the OPEX forecast for the tariff period by the transmission licensee. The licensee shall justify the OPEX forecast based on the forecast demand increase and the actual OPEX of the audited accounts of the last financial year. This OPEX shall include the expenditure on license requirements (levies, insurance, etc.) and the efficient cost of operating the transmission system. The OPEX component of the Transmission Base Allowed Revenue shall be adjusted at a rate defined by an Efficiency Factor (OPEXX) per year during the tariff period. OPEXX (%) will be fixed by the Commission before the commencement of the tariff period.
Taxes	• All taxes applicable to the Transmission Business and imposed by the relevant Tax Laws and Regulations shall be included in the tariff filing, together with the proposed adjustment mechanisms in case the tax scheme changes during the tariff period.

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Annexure 3 Cont...

Cost Component	Principle/Methodology Specified in the Regulations
Large Infrastructure Development Allowances (LID)	• Revenue with regard to CAPEX classified as LID (Large Infrastructure Development) in the LTTDP (Long-term Transmission Development Plan) and approved by the Commission will be collected from transmission system users. • For each LID, upon submission of a communication to the Commission after commissioning of such assets, the Commission will compute an annual allowance to be collected from customers, considering the debt service profile, return on equity and the depreciation over a reasonable useful life, based on an investment cost approved by the Commission. An LID allowance will be added to the Transmission Base Allowed Revenue in the year immediately after the new assets in a particular LID have been commissioned. • LID allowances will be indexed through an indexation formula defined by the Commission on a case-by-case basis.

The Royalty Price for energy supplied at discounted rates to Government by domestic generator (DGPC) in Bhutan is summarized as follows:

$$RP = AC - \frac{\sum_{n=1}^{TP} SUB_n / (1 + WACC)^n}{\sum_{n=1}^{TP} ROYALTY_n / (1 + WACC)^n}$$

Where,

- RP is the Royalty Price per kWh
- SUBn is the subsidy amount in year “n”
- ROYALTYn is the amount of Royalty Energy in year “n”

About SARI/EI

Over the past decade, USAID's South Asia Regional Initiative/Energy (SARI/E) has been advocating energy cooperation in South Asia via regional energy integration and cross-border electricity trade in eight South Asian countries (Afghanistan, Bangladesh, Bhutan, India, Pakistan, Nepal, Sri Lanka and the Maldives). This fourth and the final phase, titled South Asia Regional Initiative for Energy Integration (SARI/EI), was launched in 2012 and is implemented in partnership with Integrated Research and Action for Development (IRADe) through a cooperative agreement with USAID. SARI/EI addresses policy, legal and regulatory issues related to cross-border electricity trade in the region, promote transmission interconnections and works toward establishing a regional market exchange for electricity.

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About IRADe

IRADe is a fully autonomous advanced research institute, which aims to conduct research and policy analysis and connect various stakeholders including government, non-governmental organizations (NGOs), corporations, and academic and financial institutions. Its research covers many areas such as energy and power systems, urban development, climate change and environment, poverty alleviation and gender, food security and agriculture, as well as the policies that affect these areas.

For more information on the South Asia Regional Initiative for Energy Integration (SARI/EI) program, please visit the project website:

www.sari-energy.org