

# **Cross Border Electricity Trade in Bangladesh–Bhutan–India–Nepal (BBIN) Region: A Cost-Based Market Perspective**

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## **Abstract**

The rapid growth of electricity demand in developing nations, the availability of complementary generation resources and the emergence of digital technologies have created increased opportunities for international electricity trade. This paper proposes a framework for cross-border electricity trade in the Bangladesh-Bhutan-India-Nepal (BBIN) region that recognizes the governance challenges associated with establishing an international electricity market. We explore the lessons for BBIN region from different types of Cross Border Electricity Trade (CBET) models. Specifically, existing markets in North-West Europe (NWE), Latin America, and the United States (US) provide insights into the development of our proposed cost-based CBET framework. We provide recommendations based on our proposed CBET framework to improve efficiency and increase the extent of electricity trade in the BBIN region.

Keywords: Cross Border Electricity Trade, BBIN, Cost-based market, Developing countries

## 1. Introduction

In this paper, we propose a market-based framework for increasing the volume and efficiency of international electricity trade in the Bangladesh-Bhutan-India-Nepal (BBIN) region. A number of factors support this goal. In south Asia, 100 million people do not have access to electricity [1]. In addition, electricity demand in the region is expected to grow at an average rate of 6% per year [2]. Finally, the hydropower potential of Nepal, Bhutan, and India is 150 gigawatts (GW), out of which only 17% is currently utilized [3].

International cooperation in the development of these hydropower resources could allow the region to meet its growing electricity demand in a fossil-free manner. In a feasibility study for Cross Border Electricity Trade (CBET) in the BBIN region, the development of hydropower projects in Nepal and Bhutan was found to produce substantial economic benefits, with a benefit-to-cost ratio ranging from 3.7 to 102 [4]. Another study conducted using an electricity planning model for CBET in South Asia, estimated 8% reduction on CO<sub>2</sub> emissions for the 2015-40 time period associated with the introduction of a regional power sector [5]. .

These facts motivate the need for an efficient market mechanism to facilitate international trade of electricity in the BBIN region [6]. Accordingly, in Section 2, we first review and discuss the motivation for cross-border electricity trade in the BBIN region. Section 3 describes the structure of the electricity supply industry in the BBIN region. Section 4 discusses features of different types of electricity market models that exist around the world and their implications for the design of a CBET model for the BBIN region. Finally, Section 5 presents our cost-based market framework for CBET in the BBIN region. Section 6 summarizes and concludes.

## 2. Motivations for cross-border energy trade

### 2.1 Diversified generation mix

The electricity generation mix of the BBIN region is a key input to any assessment of the potential for cross-border electricity trade in the region. The energy sources in Nepal consist mainly of biomass, hydroelectricity, petroleum products, natural gas, and coal. Nepal has a huge hydropower potential of 83 GW out of which 42 GW is feasible after accounting for environmental impacts. At present, hydropower capacity is 1.3 GW, and as shown in Figure 1 in 2018, virtually all Nepal's electricity is produced by these resources. Almost 78% of the population has access to grid-connected electricity with a modest annual per capita consumption of 245 kW [5].

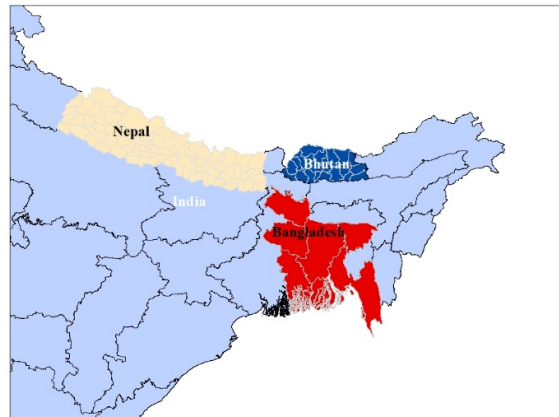
Figure 1 demonstrates that the electricity generation mix of Bhutan is predominantly based on hydropower with very small shares of solar and wind energy. In Bangladesh, natural gas-fired power plants supply almost 76% of the electricity produced, followed by hydro (21%), as shown in Figure 1. In India, coal-fired generation units supply the vast majority of electricity produced. Finally, the electricity production of India in 2018 dwarfs the electricity production of Bangladesh, Bhutan and Nepal. Nevertheless, the diversified generation mix of the BBIN region and the massive potential of hydropower energy in Nepal and Bhutan point to the existence of significant benefits for these countries from trading electricity.

With huge hydro potential (more than 100 GW) in Bhutan and Nepal [3] and growing electricity demand in neighbouring nations like India and Nepal, there is an opportunity for meeting this demand in a less carbon-intensive manner through international trade of electricity. Geographically as observed in Figure

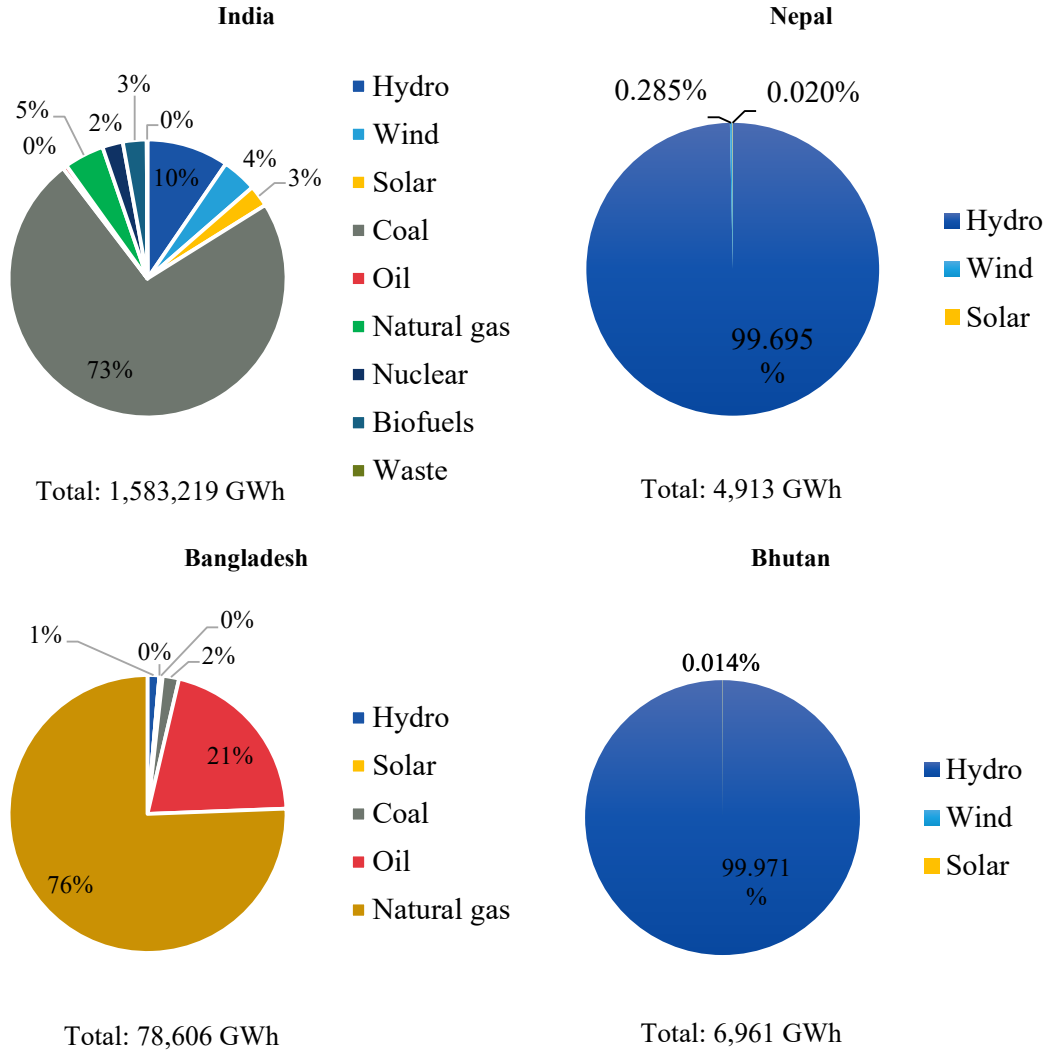
1, India offers the opportunity to interconnect the Bangladesh, Bhutan and Nepal electricity supply industries. These three countries all share borders with the eastern part of India and these shared borders could host transmission lines that interconnect India with these countries and each other. If Bhutan, Nepal, and Bangladesh want to trade electricity with each other, these transmission lines must pass through India, giving a positional advantage to India. Finally, the transmission infrastructure in India is the most developed among the BBIN countries, which further supports the possibility of international electricity trade in the region.

Hydropower resources have the potential to store significant amounts of energy, which can reduce the cost of integrating intermittent wind and solar resources and increase the opportunities for electricity trade within the region [6], [7]. However, if these hydroelectric resources do not have sufficient storage capacity, the need to operate these units because of heavy rainfall or melting of snow can reduce the amount of cross-border electricity trade. Consequently, the pattern of development of hydroelectric resources in the BBIN region depends crucially on the extent to which there is a desire among the countries to foster electricity trade within the region.

The potential for cross-border electricity trade in the BBIN region is explored in several studies [3], [8]. These studies argue that this trade would benefit all countries and have significant positive socio-economic impacts. An analysis of trade between India and Nepal observed that the importing energy from Nepal would not adversely impact the cost of solar and wind integration in India [9]. Any energy generated by Nepal that is not consumed there can be consumed by India. Consequently, electricity trade between Nepal, Bhutan, and India will be highly beneficial to Nepal and Bhutan and hydroelectric plants in these two countries can aid in the integration of intermittent wind and solar resources in India.



(a)



(b)

Figure 1: a) The BBIN region

b) The electricity generation mix by source in 2018 in BBIN region[10]–[12]

## 2.2 Different load patterns

Besides than the generation mix and geographic location of each country in BBIN region, the load levels across months of the year and hours within the day in the countries of BBIN region can facilitate the trade of electricity among these countries. Figure 2 plots the monthly demands for India, Bangladesh, and Nepal.

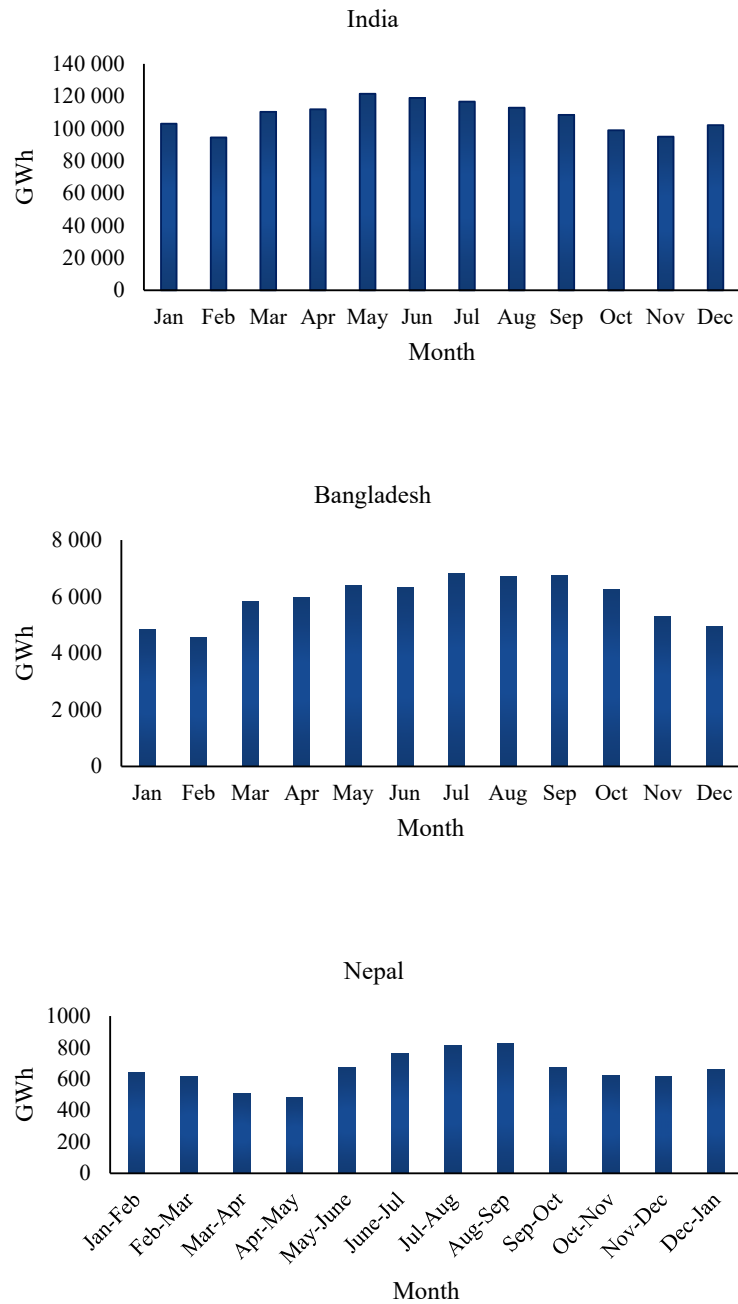


Figure 2: Monthly demand in Bangladesh (2019), India (2019), and Nepal (2019/20) [13]–[15]

The seasonal demand for electrical energy among countries in the BBIN region influences the amount of energy that can be traded. Because the electricity trade will predominantly involve the export of hydroelectric energy, the seasonal demand for electricity in Bhutan and Nepal plays a critical role in determining the feasibility of trade. In the monsoon season, there is ample energy available from hydroelectric resources in Bhutan and Nepal which can be sold to India. Figure 2 also shows that the pattern of monthly demands in these three countries, which indicates the potential for mutually

beneficial electricity trade within the region. In Figure 3, a typical summer day (month of May) and a typical winter day (December) in BBIN region is plotted.

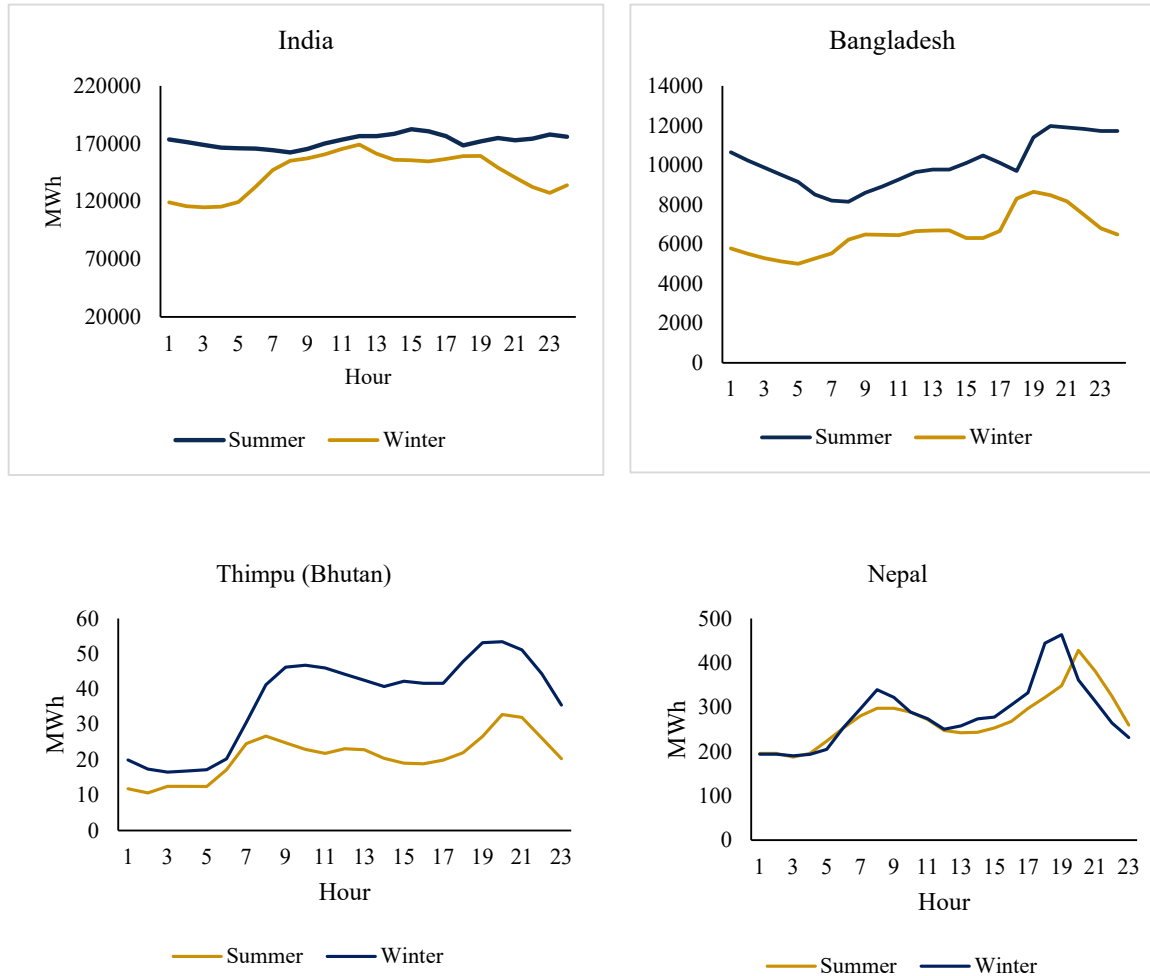


Figure 3: Hourly load pattern of BBIN [14], [16]–[18]

Figure 3 presents average hourly patterns of demand within the day in Summer (May) and Winter (December) months in the countries of the BBIN region. Demand in the summer is typically less than in the winter in Thimpu, Bhutan. The same outcome occurs in Nepal to a lesser extent. In India, the demand during the daytime in summer is high due to cooling needs. These demand patterns throughout the day suggest opportunities Bhutan and Nepal to flatten the pattern of energy production throughout the day relative the pattern of their internal demand by selling electricity to India and Bangladesh, particularly during the summer months when the demand in Bhutan and Nepal is low and the demand in Bangladesh and India is high.

### 2.3 Existing electricity trade in the BBIN region

Trading of electricity between India-Nepal, India-Bangladesh, and India-Bhutan currently takes place through bilateral agreements. Figure 4 shows the total net exchange of power in 2019 for these three

bilateral trading regimes. Bhutan was a net exporter to India, whereas Bangladesh and Nepal were net importers from India.

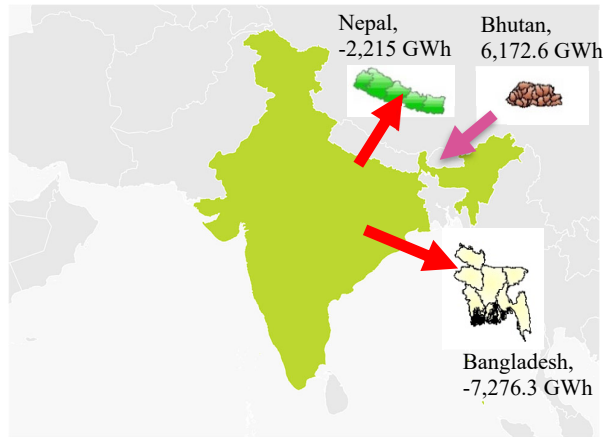
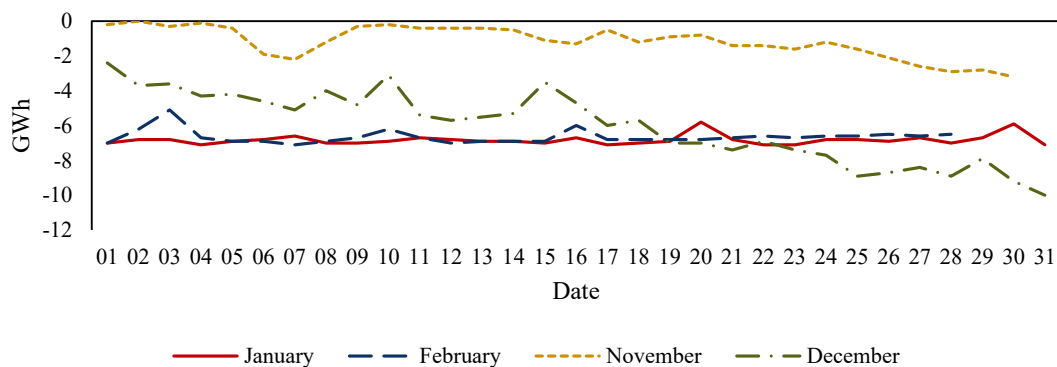


Figure 4: Inter regional power transfer for the year 2019 in GWh [15]

The electrical energy exports from Nepal and Bhutan to India are high during the monsoon season, due to the availability of water. They then decrease starting in December until June. As observed in the months of September-October in Figure 3, the demand in Nepal is lower and the demand in India higher, so electricity is typically exported to India from Nepal during these months.

The daily import and export of electricity between India and Nepal is shown in Figure 5. The impact of the seasons of the year can be observed in the pattern of traded electricity. There are substantial exports from India to Nepal from January to June. These start to decrease in July with the onset of the monsoon season. The export of electricity from India to Nepal is substantial during the months of December to June, after which the monsoon starts and exports decreases. Demand remains low during these summer months but generation is high, and demand in Bangladesh and India is high, which provides the potential for mutually beneficial trade. However, as shown in Figure 4, Nepal is a net importer for India. If Nepal is able to unlock its substantial hydro potential, it is likely to become a net exporter to India, which is experiencing significant demand growth.



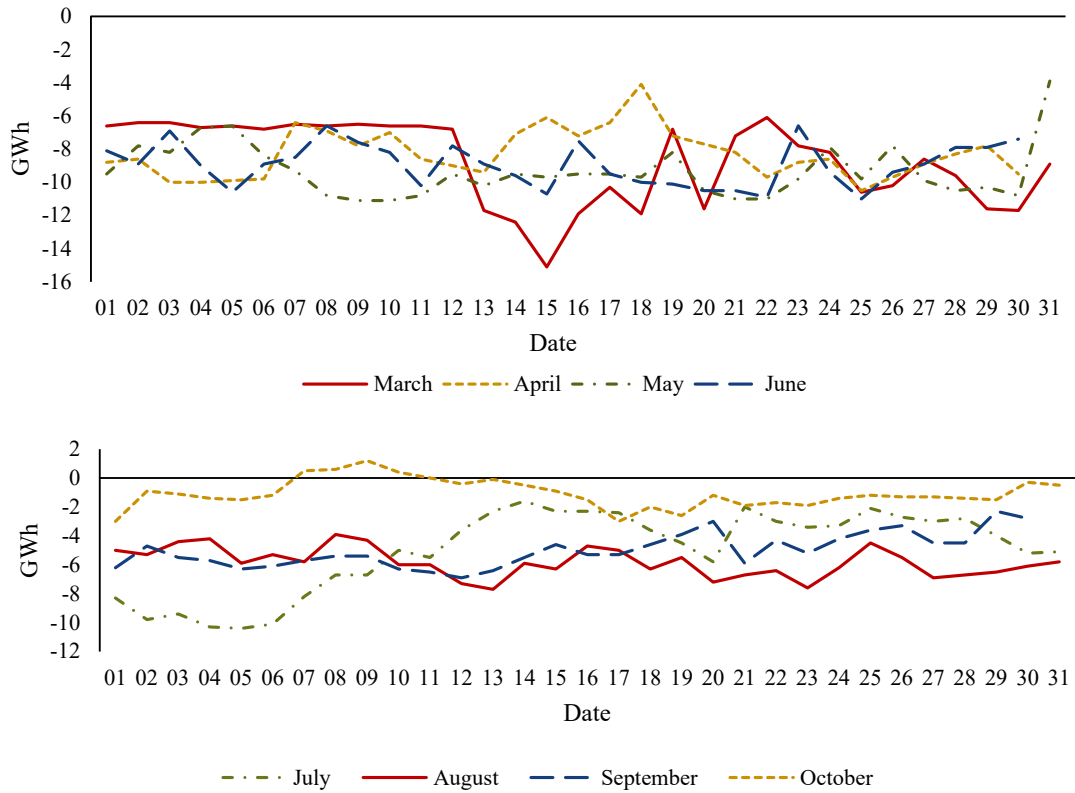


Figure 5: Daily trade<sup>1</sup> between India and Nepal in 2019 [15]

Electricity flows between India and Bhutan in different directions, depending on the season. During summer, Bhutan sells electricity to India, whereas in winter Bhutan buys from India. The impact of the seasons of the year on the pattern of trade between India and Bhutan is shown in Figure 6. There is a substantial amount of electricity traded between India and Bhutan during the wet season. The monsoon season increases the level of water in Bhutan leading to larger flows of electricity in the months of June, July, and August with a steady decline starting in August until December due to winter. The reason for this decline in trade is that the winters are drier in Bhutan with lower average rainfall and higher electricity demand for heating. Exports from Bhutan have increased from 1,460.5 GWh in 2000 to 6,182.5GWh in 2019. There has also been a steady increase in imports from Bhutan by India, due to high hydropower energy production in Bhutan. India has invested in several hydropower plants in Bhutan to access low-cost renewable electricity available there, which benefits both countries.

<sup>1</sup> A negative value indicates export of electricity from India to Nepal and a positive value indicates import of electricity from India to Nepal.



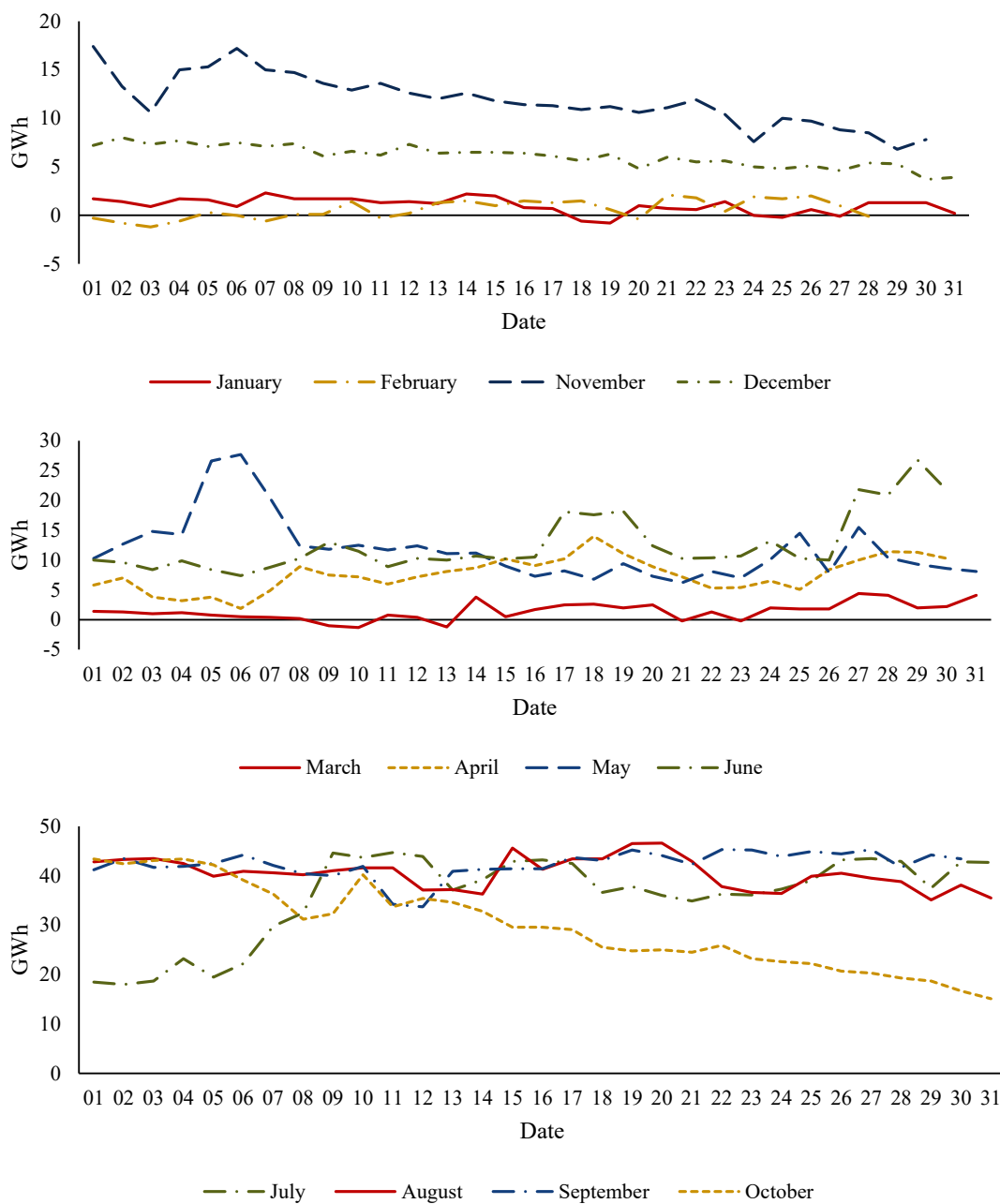


Figure 6: Daily electricity trade between India and Bhutan in 2019 [15]

Trade between India and Bangladesh involves a constant demand for imports from Bangladesh as shown in Figure 7, because the domestic supply of electricity is not enough to meet the growing demand there. The demand for electricity in Bangladesh decreases a little during the winter, but increases in summer, with the maximum demand occurring during the monsoon season. This seasonal variation in the need for electricity in Bangladesh offers an opportunity for Bhutan and Nepal, where electricity generation peaks during the monsoon season, because of water availability. Because they do not share a border with Bangladesh, for Nepal and Bhutan to trade electricity with Bangladesh, the transmission network lines that carry this energy must pass through India. A multi-country, market-based approach for electrical

energy trade offers an opportunity to unlock the potential for efficient use of generation resources in the BBIN region to meet the annual hourly demands in these four countries.

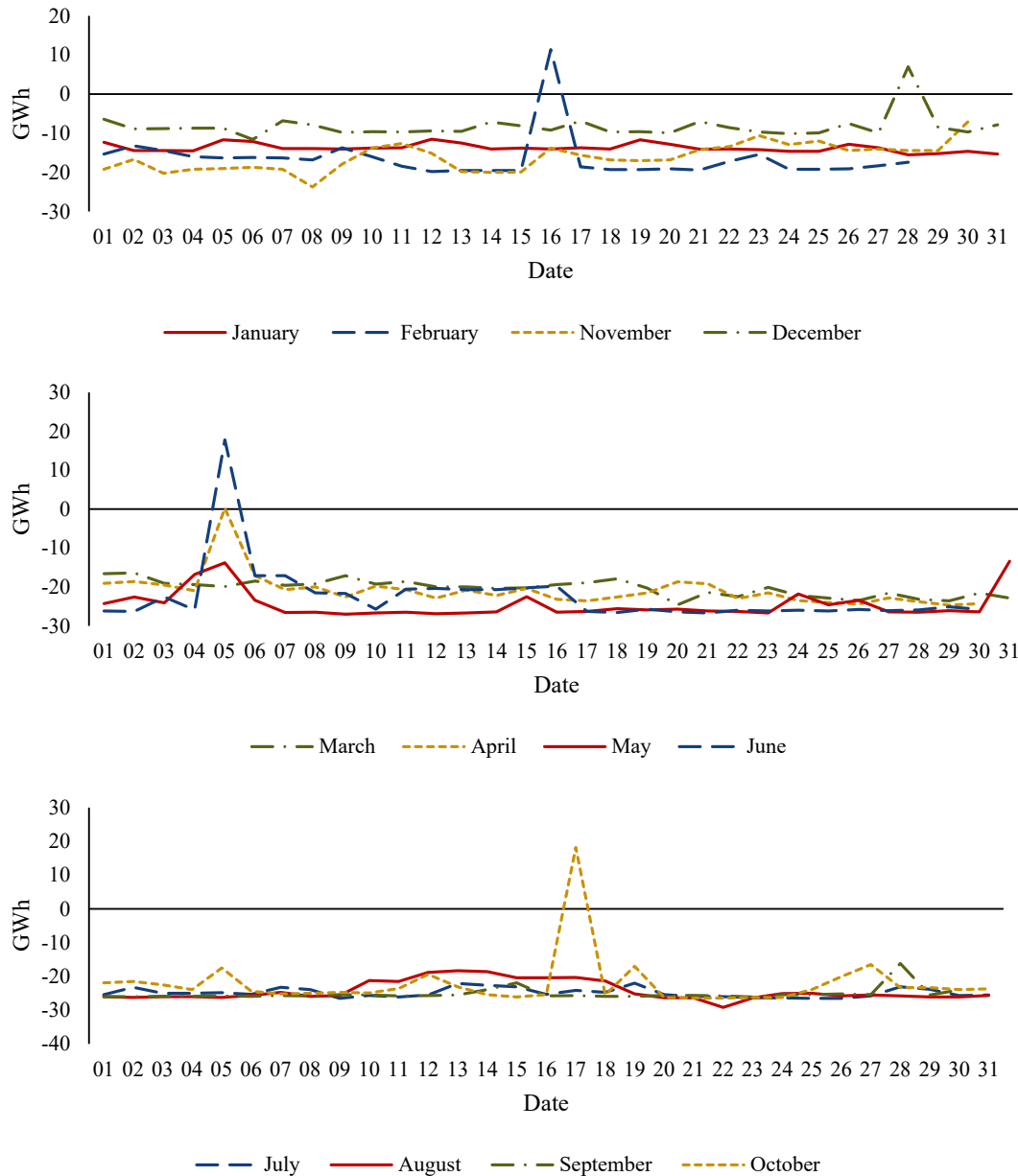


Figure 7: Daily electricity trade between India and Bangladesh in 2019 [15]

Expanded transmission infrastructure in the BBIN region and a market mechanism to guide the operation of this infrastructure can facilitate the efficient use of existing generation capacity and construction of new generation capacity to serve demand in these four countries. The analysis in Section 3.2 quantifies the economic benefits to the BBIN region of such an outcome.

### 3. Electricity-industry structure in the BBIN region: a brief overview

The existing structure of the electricity supply industries in the BBIN countries region must be accounted for in the design of a market-based CBET. The electricity supply industry in Nepal is still a government-owned vertically integrated geographic monopoly. There are some Independent Power Producers (IPPs)

that sell their electricity to Nepal Electricity Authority (NEA), which is responsible for the generation, transmission and distribution of electricity along with system operation and trading [19]. The policy for the electricity supply industry is managed by the Ministry of Energy (MoE) and regulatory aspects by the Electricity Tariff Fixation Commission (ETFC) under the Department of Electricity Development (DOED). Bhutan and Bangladesh have partially unbundled their industry structures with a separate generation utility (single firm for Bhutan and multiple firms for Bangladesh) and transmission utility (single firm), for each country. In Bhutan, the Ministry of Economic Affairs is responsible for policy design and the Bhutan Electricity Authority designs regulatory mechanisms. The generation utility is Druk Green Power Corporation (DGPC) and the Bhutan Power Corporation (BPC) is responsible for the transmission network, system operation, and distribution of electricity to final consumers. Similar to Bhutan, Bangladesh also has a partially unbundled structure with the Ministry of Power, Energy and Mineral Resources (MPEMR) designing policy. The Bangladesh Energy Regulatory Commission (BERC) designs regulatory mechanisms. There are generation plants owned by the government and IPPs. Power Grid Company of Bangladesh is the transmission and system operations utility. The distribution companies in Bangladesh are Bangladesh Power Development Board (BPDB), Dhaka Power Distribution Company (DPDC), Dhaka Electricity Supply Company (DESCO), West Zone Power Distribution Company Ltd (WZPDCL) and the Rural Electrification Board (REB), and all of them are government owned companies.

Compared to the other three countries, India's market structure is completely unbundled with separate utilities for generation, transmission, and distribution. The Ministry of Power (under the Government of India), and the Power/Energy Department under the State Government, design policies for the nation and states. The Central Electricity Regulatory Commission (CERC) is the key regulator of the power sector in India along with the relevant State Electricity Regulatory Commission (SERC) and Joint Electricity Regulatory Commission for states and union territories, respectively. Generation of electricity is shared by Central Generating Stations, State-owned generation companies, IPPs, Merchant Power Plants and Captive Power Plants. Central and State transmission utilities own the transmission network. The distribution network is shared by state-owned and private distribution companies. The system operation entities in India are the national load dispatch centre, state load dispatch center and local Power Supply Company (POSOCO). For trading, Inter-state Licensees and Intra-state Licensees enter into agreements to trade electricity.

Most wholesale electricity in India is traded through long term contracts. A market-based economic dispatch (MBED) principle is used for its short-term market. Each hour a market clearing price (MCP) is determined using a generation merit order constructed based on the offer price and offer quantity pairs submitted by each generation unit owner to the market/system operator. A least cost optimization problem is solved with these offers to determine market-clearing prices and which generation units are scheduled to operate to serve demand. The total volume of short term market transactions was 12% of total electricity generation in 2018-19, out of which 69.45% was traded on the power exchanges (a day ahead market and term-ahead market<sup>2</sup>) [20].

The market structure in India, with clearly defined market actors, can aid in the future development of a market-based CBET for the BBIN region, thereby optimizing the economic benefits of the energy trade. There are no existing power exchanges in Bhutan, Bangladesh, and Nepal. However, the India Energy Exchange has planned to allow Nepal, Bangladesh, and Bhutan to participate in this market.

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<sup>2</sup> Term ahead are a type of forward contract and are limited to 11 days ahead of delivery.

These transactions will take place through an existing trading licensee in India. Recall that Nepal and Bangladesh are net importers from India and Bhutan is a net exporter.

At present, most of the trading agreements in BBIN region are government to government. Moving towards a multilateral arrangement with multiple buyers and multiple sellers would likely be necessary to increase the volume of trade. The BBIN region transmission network is not yet sufficient to allow significant trading volumes in the region. The earthquake in Nepal in 2015 and COVID-19 pandemic have also slowed the development of this market. The Nepal Electricity Authority recently approved formation of markets that can facilitate the CBET such as a Day Ahead Market (DAM), Term Ahead Market (TAM), and long term, medium term, and short term power trading[14].

**a. Transmission network in BBIN region**

To evaluate the potential for market-based energy trade, it is essential to understand the capabilities of the existing transmission network in the BBIN region.

Trade between India and Nepal started in Aug 2018, when a 400kV transmission line from Dhalkebar to Muzaffarnagar was charged at 220kV. The 400 kV to 200 kV conversion and installation of three 315 MVA transformers was expected to be completed by the end of 2020. Discussions for another line between India (Gorakhpur) and Nepal (Butwal) were finalized in October 2019 along with a detailed study of two more 400 kV transmission lines between Purnia and New Duhabi and another one between Bareilly and Limki. In the northern zone of India, Nepal is connected to India via the 132 kV Tanakpur-Mahendranagar line. In the eastern zone of India, Nepal is connected to India via the 132 kV-Bihar-Nepal line and 220 kV-Muzaffarpur-Dhalkebar DC line. There has been a transformer upgrade at Tanakpur substation which has further increased the volume of cross-border trading.

There are plans to construct 16.5 km second circuit transmission line on existing double circuit towers of Kataiaya-Kushaha 132kV transmission line so that the switching capacity is increased to a three phase substation with a 132/11 kV 22.5 MVA transformer. These plans are motivated by a complementary supply and demand scenario where there is surplus energy in Nepal and high demand in India during the wet season in Nepal, with the opposite situation in the dry season in Nepal. There are several projects under construction between India and Nepal like the Hetauda-Dhalkebar-Inaruwa 400 kV Substation Expansion Project. This project would connect the Muzaffarpur (India) substation via Dhalkebar and also Hetauda and Inaruwa via the Hetauda-Dhalkebar-Inaruwa 400kV transmission line. The Hetauda-Dhalkebar-Inaruwa 400kV Transmission Line project aims to establish a HVDC capability of 1,000 MW for increasing trade with India and the reliability of power supply to the region. [14]

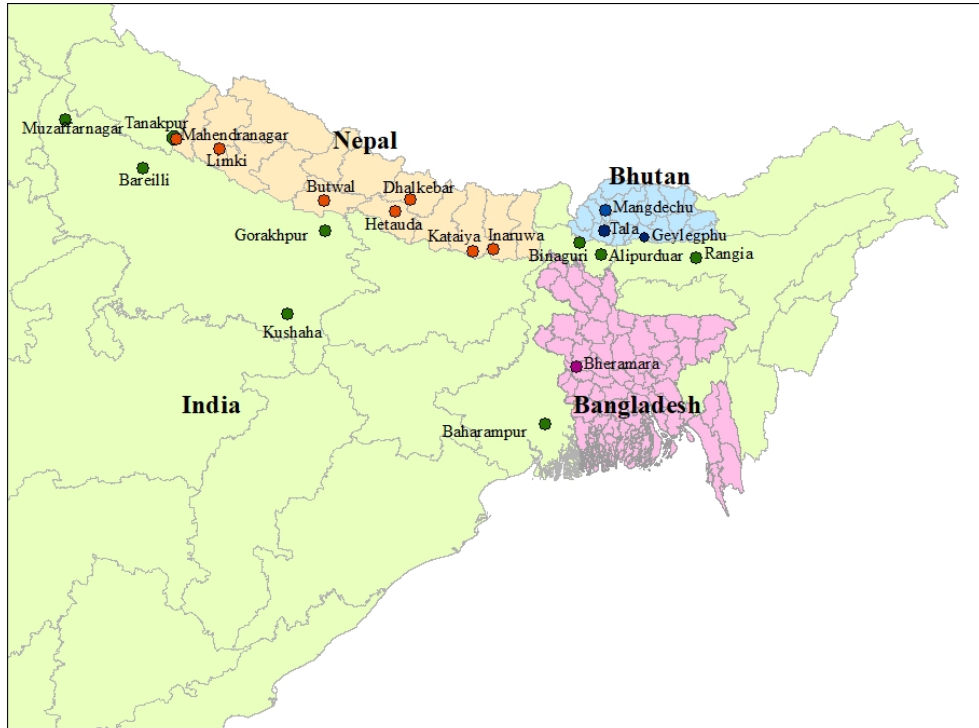


Figure 8: Location in the BBIN region where the transmission lines are located and planned

The locations in the BBIN region where the transmission lines referred to above are located and planned is shown in Figure 8. Note that both the Eastern and Northeastern regions in India are connected to Nepal, Bhutan and Bangladesh.

Bhutan is connected to India via five different transmission lines operating in two zones (Northeastern region and Eastern region) in India. The transmission lines connecting the Eastern Region (ER) are 400kV Mangdechhu-Alipurduar 1&2. The transmission lines 132KV-Geylegphu – Salakati and 132kV Motanga-Rangia connect Bhutan with north eastern region (NER) in India. As discussed earlier, Bhutan is a net exporter to India [15].

Bangladesh is connected to the Eastern and North Eastern zones in India. Bangladesh is connected to the Eastern zone via the Bheramara HVDC line. [21] The 132KV-Surajmani Nagar–Comilla (Bangladesh)-1 and 132KV-Surajmani Nagar-Comilla (Bangladesh)-2 connect to the Eastern zone in India [18].

Capacity of all of the transmission lines referred to in this section and the network configuration are used in the transportation model developed in Section 3.2 to simulate energy flows in the BBIN region and calculate the potential economic benefits of a regional market.

**b. A simple transportation model**

To quantify the economic benefits from electricity trade in BBIN region, a simple transportation model was designed with the four nations as four net injection nodes. [22] Bidirectional flow in the network allows import and export of electricity. A value of lost load (VOLL) is specified to account for the cost of unmet demand. The model minimizes the variable costs of serving demand plus the cost of any unmet demand valued at the VOLL subject to the constraint that the amount of energy injected at each node

equals the amount withdrawn at that location and the fact that net flows on all transmission lines are less than the capacity of the transmission lines and no generation unit can produce more energy than it is capable of producing [22], [23]. The model is solved for one period. The optimization problem minimizes the cost of serving the demand with the existing generation sources while honouring the line flow limits, generation capacity and load balance constraints.

**Notation:**

**Sets:**

Set of generators  $G$   
Set of Transmission lines  $L$   
Set of System Nodes  $U$

**Indices**

System nodes  $u, n \in U$   
Generators  $g \in G$   
Generators at a node  $g \rightarrow u$   
Transmission Lines  $l \in L$   
Lines originating from a node  $l \leftarrow u$   
Lines terminating at a node  $l \rightarrow n$

**Parameters**

Short Run Marginal Cost (SRMC) of a generator  $C_g$   
Demand at a node  $D_u$   
Value of Lost Load  $V$   
Line Limits  $F_l$   
Generator Capacity  $P_g$

**Variables**

Demand Served  $d_u$   
Line Flows  $f_l$   
Generaton Schedule  $p_g$

**Model**

$$\underset{P_g, D_u, f_l}{\text{Minimise}} \sum_{g \in G} C_g P_g + \sum_{u \in U} (D_u - d_u) V$$

Subject to:

$$\sum_{g \rightarrow G} C_g - d_u = \sum_{l \leftarrow u} f_l - \sum_{l \rightarrow u} f_l : u \in U$$

$$-F_l \leq f_l \leq F_l : l \in L$$

$$0 \leq d_u \leq D_u : u \in U$$

$$0 \leq p_g \leq \bar{P}_g : g \in G$$

The input data is based on the generation capacity and demand data described in Section 2.3 and the transmission capacity data described in Section 3.1. A sample dataset used for the simulation is shown in Tables 1 and 2. Generator Short Run Marginal Cost (SRMC) is the marginal cost of generation, which is considered as constant for the model and is assumed based on the historical flows among the nations in the BBIN region.

Table 1: Input node data

Node	SRMC (\$/MWh)	Demand (MWh)	Maximum generation (MW)
India	15	175000	349000
Bangladesh	40	14796	19630
Bhutan	10	1500	1660
Nepal	20	2415	3112

Table 2: Line data

Line	Maximum Flow (MW)
India to Nepal	1042.5
India to Bangladesh	1360
India to Bhutan	2322

The simulations yield annual flows between the nations. As observed from Table 3, the lines between India to Nepal and India to Bangladesh are congested (utilized at maximum capacity) whereas the line from India to Bhutan is not congested (unused capacity). Also, the Locational Marginal Price (LMP) for Bhutan is low as compared to Nepal and Bangladesh, which exemplifies that, cheaper electricity can be bought by India from Bhutan.

Table 3: Load flows based on the transportation model

Lines	Flows (MW)	Congestion Price (\$/MWh)
India to Nepal	1042.5	-5.0
India to Bangladesh	1360	-25
India to Bhutan	-160	0

Table 4: LMP based on the model

Country	Nodal price (\$/MWh)
India	15
Bangladesh	40
Bhutan	15
Nepal	20

The model output shows that India exports to Nepal and Bangladesh and imports from Bhutan, which is in line with the actual flows among the countries discussed in Section 2.3. The lack of transmission congestion in India-Bhutan corridor implies that Bhutan could invest in generation capacity and sell more energy into India. The benefits from the investment will be 5 \$/hour per MW of installed capacity based on the above analysis. Furthermore, as per the report of IRENA, the installed hydro in Bhutan is around 1,600 MW [24] but the technical feasible potential is of about 23,000 MW [25]. It is likely that 70% of the electricity produced would be exported to India as noted in the South Asia Sub regional

Economic Cooperation (SASEC) report [26] . It is estimated that electricity exports to India would constitute 25% of the GDP of Bhutan and 40% of domestic revenues [27]. With this magnitude of expected economic benefits from electricity exports to India, establishing an efficient electricity trading arrangement would definitely prove beneficial to Bhutan as well as other nations in the BBIN region that can gain access to cheaper and greener electricity.

The transmission congestion from India to Nepal and India to Bangladesh implies a significant economic benefit to all three countries if these two transmission corridors are expanded. The expected economic benefits to the region are greater for a one MW increase in the India to Bangladesh corridor capacity versus India to Nepal corridor capacity: \$25/hour/MW of benefits for expanding the India-Bangladesh corridor, compared to \$5/hour/MW for expanding the India-Nepal transmission corridor. These simulations also demonstrate that generation capacity expansion in Bangladesh and Nepal would likely to be profitable, while investment in both generation and transmission capacity in India would likely be profitable. The modelling results clearly demonstrate the potential for economically beneficial trade of electricity in the BBIN region. However, realizing these economic benefits requires the implementation of the appropriate mechanism governing electricity trade among the four nations in the region.

The following section provides a review of different CBET models, and the lessons drawn from them are used to propose a cost-based market mechanism for trading in the BBIN region.

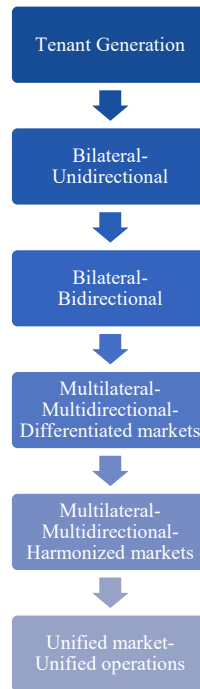
#### **4. Different existing CBET models**

##### **a. CBET models- A review**

There are a variety of CBET models currently operating globally. These models can be divided into different groups based on the extent of vertical and horizontal integration. The different types of CBET models based on the extent of vertical integration as shown in Figure 9 are discussed below.

1. **Tenant Generation:** In this type of CBET model, a dedicated cross border transmission line is used by a power plant in one country (host) to sell power to another country. This type of arrangement is made when the host country power plant is primarily built to serve the other country. Under this type of arrangement, there is a dedicated transmission line; hence any kind of disturbance like congestion, grid stability, or synchronization does not impact the host country. Because of this, the host government's role is limited to siting and tenancy decisions. The generator participating in this arrangement is called tenant generator. In this type of arrangement, the tenant generator can sign Power Purchase Agreements (PPAs), participate in the electricity market, or also sell ownership of the facility to the importing country. This typically means that the host country does not benefit in terms of energy efficiency, operational efficiency, or economic benefits with the addition of tenet generation units to its fleet. The benefits for the host country are limited to taxes and employment. This type of model is typically employed in the initial stages of energy trade between two nations, and it can provide a foundation for a future multilateral energy trading regime. The project in Himachal Pradesh in India involving a 900MW hydropower plant to sell energy from Nepal in India is an example of such type of arrangement.





*Figure 9: Different CBET models*

2. Government to government (GTG) transactions – In this type of arrangement, the counterparties are governments of the countries and trade does not necessarily take place through a formal market mechanism. For the case of hydroelectric plants, these trades can take place because irrigation and flood control policies dictate alternative use of the water. The typical GTG agreement is based on the policies and objectives of the two governments which can be outside the purview of a regular CBET.
3. Bilateral, unidirectional power flow (BUP) - In this type of CBET, there are only two jurisdictions involved but the energy flow unidirectional, which means that only one country imports power from the other. For example, Thailand imports from Lao DPR, but Lao DPR does not buy any electricity from Thailand. There can also be a transit country in between in such arrangements. Nepal is planning to export electricity to Bangladesh, and India will act as a transit country in this arrangement. This type of arrangement is suitable for initiating CBET in developing regions or to meet the demand of one power hungry nation when the resources are available in another country.
4. Bilateral, bidirectional (BB) - In this CBET both the countries involved in the agreement are involved in import and export of electricity. There is no market mechanism involved in such type of model. At present, this type of arrangement exists among India-Bhutan, India-Nepal and India-Bangladesh.
5. Integrated market exchange (IM): In this type of model, the market-clearing price is typically determined based on the least cost optimization model using offers from generators, load forecasts, and current state of the grid. The short-term price of electricity in each country is not known until this market clears. The government does not have control over the pricing or the quantity of energy transacted. The governments must, however, agree to the regulatory processes and policies to enable this market to operate. We propose a variant of this design for the BBIN region because it has greater potential for capturing the economic benefits described in the previous section. This CBET model is more advanced, and the market mechanism and

operation play an important role in setting the prices and maximizing benefits from the electricity trade. The special cases of IM are discussed below:

- Multilateral with multidirectional power trade with differentiated markets (MDM)-In multilateral modes of power trading, more than two countries are involved. In multilateral CBET with differentiated markets, the market structure differs across the participating nations. For example, the South African Power Pool or the Central American Electrical System (SIEPAC) uses this model for CBET.
- Multilateral with multidirectional power trade with harmonized markets (MHM)-This CBET type also contains three or more countries involved in the electricity trading with a harmonized market structure among the nations involved. For example, market structure and relevant regulations are harmonized for EU’s internal energy market.
- Unified market and operations (UO) - In this UO approach, the hierarchy of integration expands to the unification and a single institution is responsible for the operation. This can be the most advanced form of CBET in terms of technological needs for the operations. For example, PJM (originally, the Pennsylvania, Jersey, and Maryland Interconnection ) is one of the largest regional electricity systems in US and is responsible for both market and system operation.

Because electricity is a just-in-time product in the sense that supply must equal demand at every instance in time, most formal market models involve multiple financial settlements between buyers and sellers before the electricity is ultimately delivered in real-time. This has the advantage of allowing entities with certain demands or sources of supplies to obtain revenue certainty for a fixed quantity of production or consumption. Entities with uncertain demands or supplies of energy can trade previous purchases and sales in subsequent markets to obtain greater payment or revenue certainty for the quantity of energy they ultimately consume or produce. These forward markets can involve purchases made years in advance of delivery to a day-ahead or even hour-ahead before real-time delivery. Figure 10 presents a sample timeline of the various markets that a proposed generation unit might transact in between conception to the ultimate production of energy.



Figure 10: Different market floors for trading electricity

## 5. Proposed cost-based market for CBET for the BBIN region

This section first reviews the major challenges in designing short-term electricity markets. First is the exercise of unilateral market power by large suppliers, a problem that is likely to be even more acute for a CBET market. Second is the match between the transmission network model used to operate the market and the transmission network model used to operate the grid. Third is the role of multiple forward markets before real-time system operation to ensure efficient operation in real-time. We then propose a cost-based CBET trading market for the BBIN region that clears before the domestic market clears in any country of the BBIN region.

## 5.1. The Unilateral Market Power Problem

A major challenge to efficient short-term trading of electricity is the potential for the exercise of unilateral market power [28]. In an offer-based electricity market, a supplier that controls a significant fraction of generation capacity is likely to find it more profitable to sell slightly less energy than it is capable of supplying at a substantially higher price by offering to sell energy at a price that is significantly higher than its marginal cost production [29]. These unilaterally profitable actions can both reduce the volume of electricity trade and significantly increase the price that buyers pay for electricity. Virtually all offer-based short-term electricity markets globally have had to address unilateral market power problem [33].

The unilateral market power problem is likely to be even more challenging to address in an international electricity market because of the potential for a net exporting country to raise the prices that net importing countries pay for electricity without impacting the prices paid by their domestic consumers. Moreover, actions that raise export prices could be facilitated by the government of the exporting country to raise the revenues earned by the domestic government from sales to the importing countries. Different from single-country short-term markets, there is no international competition authority or international market regulator to punish these actions or regulate offer prices and quantities when they occur. Consequently, any international trade in electricity must be managed under mutually beneficial terms and conditions negotiated by all countries involved. These facts argue against implementing an offer-based short-term wholesale market CBET.

The experience of Latin American provides important lessons for the design of a CBET market for the BBIN region. Many Latin American countries operate what are called cost-based markets, where suppliers submit the technical characteristics of their generation units and information about the prices paid for input fuels to the market operator. This information is used to compute estimates of the marginal cost of energy for each generation unit. The market operator uses these marginal cost estimates to solve for the least cost dispatch to meet demands throughout the transmission network. Locational marginal prices for energy can be computed based on solution to this optimization problem [34]. This approach to short-term market operation prevents suppliers from exercising unilateral market power in the short-term market by setting their offer prices above their marginal cost of production.

An additional benefit of a cost-based short-term market is that it provides a credible real-time price for the energy that forward market commitments can be cleared against. For example, if a supplier in an exporting country signs a commitment to sell 500 MWh of energy at a price of \$25/MWh for some delivery period, the short-term market can be used by the seller to purchase additional energy to meet this forward market obligation if its generation units fail to produce 500 MWh or sell excess energy when short-term prices favour producing more than 500 MWh from its generation units. Because both parties to any forward contract know that the short-term price is determined using generation unit marginal costs set by the regulator rather than offers submitted by generation unit owners, they are less concerned that short-term prices will be subject to the exercise of unilateral market power when they buy or sell energy in the short-term market.

## 5.2. Locational Marginal Pricing

An important lesson from electricity market design processes around the world is the extent to which the market mechanism used to dispatch and operate generation units is consistent with how the grid is actually operated. In the early stages of wholesale market design in the US, all regions attempted to operate wholesale markets that used simplified versions of the transmission network. The single zone

or zonal markets assumed infinite transmission capacity between locations in the transmission grid or only recognized transmission constraints across large geographic regions. These simplifications of the transmission network configuration and other relevant operating constraints can create opportunities for market participants to increase their profits by taking advantage of the fact that in real-time the actual configuration of the transmission network and other operating constraints must be respected [28].

These markets set a single market-clearing price for a half-hour or hour for an entire country or large geographic region despite the fact that there were generation units with offer prices below the market-clearing price not producing electricity and units with offer prices above the market-clearing price producing electricity. This outcome occurs because of the location of demand and available generation units within the region and the configuration of the transmission network prevents some of these low-offer-price units from producing electricity and requires some of the high-offer-price units to supply electricity. The former units are typically called ‘constrained-off’ units and the latter are called ‘constrained-on’ or ‘must-run’ units [30].

A market design challenge arises because how generation units are compensated for being constrained-on or constrained-off impacts the offer prices they submit into the wholesale energy market. For example, if generation units are paid their offer price for electricity when they are constrained-on and the unit’s owner knows that it will be constrained-on, a profit-maximizing unit owner will submit an offer price far in excess of the variable cost of the unit and be paid that price for the incremental energy it supplies, which raises the total cost of electricity supplied to final consumers.

A similar set of circumstances can arise for constrained-off generation units. Constrained-off generation units are usually paid the difference between the market-clearing price and their offer price for not supplying electricity that the units would have supplied if not for the configuration of the transmission network. This market rule creates an incentive for a profit-maximizing supplier that knows its unit will be constrained-off to submit the lowest possible offer price in order to receive the highest possible payment for being constrained-off and raise the total cost of electricity supplied to final consumers.

Almost any difference between the market model used to set dispatch levels and market prices and the actual operation of the generation units needed to serve demand creates an opportunity for market participants to take actions that raise their profits at the expense of overall market efficiency. Multi-settlement wholesale electricity markets that use locational marginal pricing (LMP), also referred to as nodal pricing, largely avoid these constrained-on and constrained-off problems, because all transmission constraints and other relevant operating constraints are respected in the process of determining dispatch levels and locational prices in the wholesale market.

All LMP markets in the US co-optimize the procurement of energy and ancillary services. This means that all suppliers submit to the wholesale market operator their generation unit-specific willingness-to-supply schedules for energy and any ancillary service<sup>3</sup> the generation unit is capable of providing. Likewise, large loads and load-serving entities submit their willingness-to-purchase energy schedules.

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<sup>3</sup> Ancillary services are defined as the necessary services for reliable and safe operation of a power system. These services facilitate and support the continuous flow of electricity from the generation sites to the load sites. The frequency and voltage control services are among the well-known ancillary services. Besides, we can see services such as spinning reserves and operating reserves that are needed to maintain grid stability and security. Traditionally, ancillary services were provided by generators but in today’s electricity networks with increasing integration of intermittent renewable generation, other technologies (such as battery storage units or wind-power units) can also provide ancillary services [33].

Locational prices for energy and ancillary services and dispatch levels and ancillary services commitments for generation units at each location in the transmission network are determined by minimizing the as-offered costs of meeting the demand for energy and ancillary services at all locations in the transmission network, subject to all transmission network and other relevant operating constraints. No generation unit will be accepted to supply energy or an ancillary service if doing so would violate a transmission or other operating constraint.

An important distinction between an LMP market design and the standard European market design is the centralized commitment of generation units to provide energy and ancillary services. European markets do not typically require all generation units to submit energy offer curves into the day-ahead market and instead allow individual producers to make the commitment decisions for their generation units. A self-commitment market can result in higher cost generation units operating because of the differences among producers in their assessment of the likely market price. Self-commitment markets also do not allow the simultaneous procurement of energy and ancillary services and instead rely on sequential procurement of ancillary services after energy schedules have been determined. Oren [36] demonstrates that sequential clearing of energy and ancillary services markets increases the opportunities for generation unit owners to exercise unilateral market power in the ancillary services market because they know that units committed to supply energy cannot compete in the subsequent ancillary services market.

In contrast, LMP markets that co-optimize the procurement of energy and ancillary services ensure that each generation unit is used in the most cost-effective manner based on the energy and ancillary services offers of all generation units, not just those owned by a single market participant. Specifically, the opportunity cost of supplying any ancillary service a unit is capable of providing, will be explicitly taken into account in deciding whether to use the unit for that ancillary service. For example, if the market-clearing price of energy at that generation unit's location is 40 \$/MW, the unit's offer price for energy is 30 \$/MW, and the unit's offer price for the only ancillary service the unit can supply is 5 \$/MW, then the unit will not be accepted to supply the ancillary service. In fact, it would be accepted to supply the ancillary service only if the price for that service was greater than or equal to 10\$/MW because 10\$/MW is the opportunity cost of energy for that unit. In other words, if generator sells its generation capacity to energy market, for each MW production it receives a variable profit of 10\$ profit. This generator is willing to use its generation capacity for the ancillary-service market (and not sell it in the energy market) if it receives a profit of greater than or equal to 10 \$ per MW for the ancillary service.

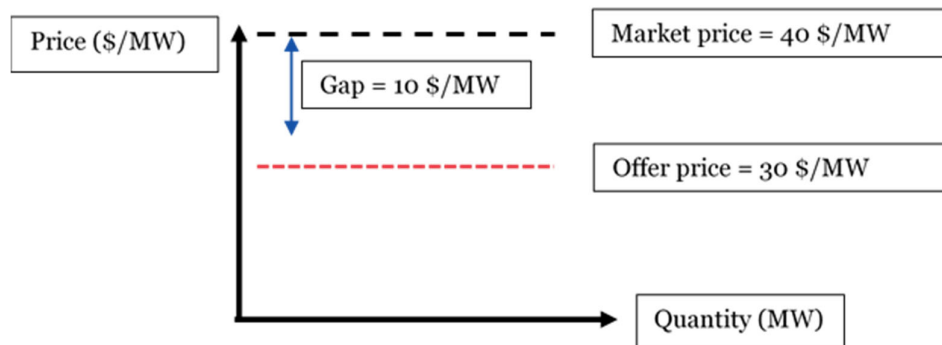


Figure 11: Market clearing for ancillary service

In contrast, self-commitment markets such as those that exist in Europe and other industrialized countries must rely on individual market participants to make the efficient choice between supplying energy or ancillary services from each generation unit.

The LMP pricing process sets potentially different prices at all locations in the transmission network, depending on the configuration of the transmission network and geographic location of demand and the availability of generation units. Because the configuration of the transmission network and the location of generation units and demand is taken into account in operating the market, only generation unit dispatch levels that are expected to be feasible in real time, given the expected configuration of the transmission network, will be accepted to serve demand. They will be paid a higher or lower LMP than other units, depending on whether the generation unit is in a generation-deficient or a generation-rich region of the transmission network.

The nodal price at each location is the increase in the minimized value of the ‘as-offered costs’ objective function (which is defined based on cost functions offered or submitted by different generators to the independent system operator) as a result of a one unit increase in the amount of energy withdrawn at that location in the transmission network. In a market with no transmission constraints selling a single product, the market-clearing price is defined the same way as the increase in minimum cost to serve one more 1 MWh of demand. In the case of a locational marginal pricing market that co-optimizes energy and ancillary services, this result generalizes to the increase in the optimized value of minimized as-offered costs associated with increasing demand at that location in the transmission network. The price of each ancillary service is defined as the increase in the optimized value of the objective function as a result of a one unit increase in the demand for that ancillary service. In most LMP markets, ancillary services are procured at a coarser level of spatial granularity than energy. For example, energy is typically priced at the nodal level and ancillary services are priced over larger geographic regions. Bohn, Caramanis, and Schweppe [34] provide an accessible discussion of the properties of the LMP market mechanism.

Another strength of the LMP market design is the fact that other constraints that the system operator takes into account in operating the transmission network can also be accounted for in setting dispatch levels and locational prices. For example, suppose that reliability studies have shown that a minimum amount of energy must be produced by a group of generation units located in a small region of the grid. This operating constraint can be built into the LMP market mechanism and reflected in the resulting locational prices. This property of LMP markets is particularly relevant to the cost-effective integration of a significant amount of intermittent renewable generation capacity in the transmission network, because additional reliability constraints may need to be formulated and incorporated into LMP market to account for the fact that this energy can quickly disappear and re-appear.

An important lesson from the US experience with LMP markets is that explicitly accounting for the configuration of the transmission network in determining dispatch levels both within and across regions can significantly increase the amount of trade that takes place between the regions. Mansur and White [37] dramatically demonstrate this point by comparing the volume of trade between two regions of the Eastern US. The Midwest and Eastern portion of PJM were compared, before and after these regions were integrated into a single locational marginal pricing market that accounts for the configuration of the transmission network throughout the entire integrated region. Average daily energy flows from the Midwest to Eastern portion of PJM almost tripled immediately following the integration of the two regions into an LMP market. There was no change in the physical configuration of the transmission network for the two regions. This increase in energy flows was purely the result of incorporating the

two regions into a single LMP market that recognizes the configuration of the transmission network for the two regions in dispatching generation units. This result strongly argues in favour of an LMP market design for CBET market in the BBIN region.

### **5.3. Multi-Settlement Markets**

Multi-settlement nodal-pricing markets have been adopted by all US jurisdictions with a formal short-term wholesale electricity market. A multi-settlement market has a day-ahead forward market that is run in advance of real-time system operation. Generation unit owners submit unit-level offer curves for each hour of the following day and electricity retailers submit demand curves for each hour of the following day. The system operator then minimizes the as-offered cost to meet these demands simultaneously for all 24 hours of the following day subject to the anticipated configuration of the transmission network and other relevant operating constraints. This gives rise to LMPs and firm financial commitments to buy and sell electricity each hour of the following day for all generation unit and load locations.

The day-ahead market typically allows generation unit owners to submit their start-up and no-load cost offers as well as energy offer curves, and both of these costs enter the objective function used to compute hourly generation schedules and locational marginal prices for all 24 hours of the following day. This logic implies that a generation unit will not be dispatched in the day-ahead market unless the combination of its start-up and no-load costs and energy costs are part of the least cost solution to serving hourly demands for all 24 hours of the following day. As noted earlier, to the extent that generation unit owners submit start-up, no-load and energy offer curves that are representative of their actual costs, the total cost of committing and dispatching the generation units that arises from this centralized unit commitment process is likely to be less than the total commitment and dispatch costs that result from a self-commitment market, such as those that exist in Europe and other industrialized countries.

The energy schedules that arise from the day-ahead market do not require a generation unit to supply the amount sold or a load to consume the amount purchased in the day-ahead market. The only requirement is that any shortfall in a day-ahead commitment to supply energy must be purchased from the real-time market at that same location or any production greater than the day-ahead commitment is sold at the real-time price at that same location. For loads, the same logic applies. Additional consumption beyond the load's day-ahead purchase is paid for at the real-time price at that location and the surplus of a day-ahead purchase relative to actual consumption is sold at the real-time price at that location.

In all US wholesale markets, real-time LMPs are determined from the real-time offer curves from all available generation units and dispatchable loads by minimising the as-offered cost to meet real-time demand at all locations in the geographic region that contains the LMP market taking into account the current configuration of the transmission network and other relevant operating constraints. This process gives rise to LMPs at all locations in the transmission network and actual hourly operating levels for all generation units. Real-time imbalances relative to day-ahead schedules are cleared at these real-time prices.

To understand how a two-settlement market works, suppose that a generation unit owner sells 50 MWh in the day-ahead market at 60 \$/MWh. It receives a guaranteed 3000 \$ in revenues from this sale. However, if the generation unit owner fails to inject 50 MWh of energy into the grid during the specified delivery hour of the following day, it must purchase the energy it fails to inject at the real-time price at that location. Suppose that the real-time price at that location is 70 \$/MWh and the generator only injects 40 MWh of energy during the hour in question. In this case, the unit owner must purchase the 10 MWh

shortfall relative to its day-ahead schedule at 70 \$/MWh. Consequently, the net revenues the generation unit owner earns from selling 50 MWh in the day-ahead market and only injecting 40 MWh is 2300 \$, the 3000 \$ of revenues earned in the day-ahead market less the 700 \$ paid for the 10 MWh real-time deviation from the unit's day-ahead schedule.

If a generation unit produces more output than its day-ahead schedule, then this incremental output is sold in the real-time market. For example, if the unit produced 55 MWh, then the additional 5 MWh beyond the unit owner's day-ahead schedule is sold at the real-time price. By the same logic, a load-serving entity (what Europeans call a supplier) that buys 100 MWh in the day-ahead market but only withdraws 90 MWh in real-time, sells the 10 MWh not consumed at the real-time price. Alternatively, if the load-serving entity consumes 110 MWh, then the additional 10 MWh not purchased in the day-ahead market must be purchased at the real-time price.

By this same logic, a multi-settlement nodal-pricing market is well-suited to countries that do not have an extensive transmission network because it explicitly accounts for the configuration on the actual transmission network in setting both day-ahead energy schedules and prices and real-time output levels and prices. This market design eliminates much of the need for ad hoc adjustments to generation unit output levels that can increase the total cost of wholesale electricity to final consumers because of differences between the prices and schedules that the market mechanism sets and how the actual electricity network operates.

#### **5.4. Cost-Based CBET Market for BBIN Region**

Because there are likely to be many periods when one or more suppliers to an offer-based CBET market for the BBIN region would have a significant ability to exercise unilateral market power through the offer prices they submit, it would not be advisable to attempt an offer-based short-term market for the BBIN regions. For example, if Nepal wants to trade with Bangladesh, the transmission network needs to pass through India. Due to such reasons, we recommend a cost-based CBET market, where the market operator uses information on the technical characteristics of generation units and information<sup>4</sup>. In addition, because, as illustrated by the simulation in Section 3.2, transmission network constraints are likely to bind across countries in the CBET, this market should employ locational marginal pricing which accounts for the configuration of the grid and other relevant operating constraints in setting locational prices and quantities transacted. Finally, this market should be run in advance of the operation of the wholesale markets in any of the BBIN countries. Once all of the BBIN countries adopt market mechanisms for these domestic electricity supply industry, this cost-based market structure could be reconsidered.

##### **5.4.1. Determining Cost-Based Offers**

A crucially important component of the proposed cost-based CBET market is the process used to determine the cost-based offers of each country. This process should be established jointly by the BBIN regulator and transparent to all market participants. For example, the opportunity cost of water for the hydroelectric energy dominated countries would be determined from a model-based process based on publicly available data that any market participant could replicate. A similar process would determine the variable cost of generation units with non-zero input fuel costs. The variable cost would be determined from a publicly disclosed heat rate and the variable cost of fuel could be based on a publicly

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<sup>4</sup> We think that running a cost-based market would limit the opportunities for India to take advantage of its size to exert influence on trade flows and prices. Proper analysis of this situation requires some relevant data pieces which we do not have at the moment.



available price index for the fuel. Once again, the most important feature of this process is its transparency to all market participants. All market participants should believe that a good faith effort has been made to obtain credible variable cost and opportunity cost of water estimates for all generation units that participate in this market. A final component of this process of determining generation unit cost estimates is the process for updating these costs. There should be a clearly process for updated these costs as new information on any technical characteristics of the generation units, input fuel prices and water availability becomes available. The ultimate goal of the design of this cost determination process is a transparent (to all market participants and country-specific regulators) mechanism for determining these costs and how they change over time that all countries agree upon. Galetovic, Munoz and Wolak [31] discuss the details of the process of computing the opportunity cost of water and the variable cost of thermal generation units for the cost-based short-term market in Chile, which has been operating since the early 1980s.

#### **5.4.2. Pricing Transmission Network and Other Relevant Operating Constraints**

The CBET market should produce day-ahead schedules for all 24 hours of the following day that specify net imports and net exports from each of the BBIN countries for each of the 24 hours of the following days. These net import and export schedules will be determined from the generation unit-level variable costs described in the previous section and forecasts of the hourly demands in each BBIN country during the 24 hours of the following day and the market operator's best estimate of the likely state of the transmission network configuration and other relevant operating constraints during that day. This market will produce prices and generation unit schedules for all generation units in the BBIN region for all 24 hours of the following day. The resulting prices will be used to pay exporting countries for their net exports and charge importing regions for their net imports [39].

The resulting hours' net import and export schedules determined from this market-clearing mechanism will be treated as firm deliveries to and from each country the following day. For example, if Bhutan is scheduled to export 10 MWh to India during an hour, then the Bhutan market operator must ensure that 10 MWh more energy of energy is produced in Bhutan than is consumed there and the market operator in India should recognize that 10 MWh less of energy will be produced in India than the demand in that country. The market/system operators in each of the BBIN countries would be free to determine how to share the revenues from exporting energy and the cost of importing energy into their country between domestic suppliers and consumers.

#### **5.4.3. Settling Net Imports and Exports in Domestic Markets**

As noted in Section 3, some BBIN countries, such as India, have formal short-term wholesale electricity markets and others are vertically integrated monopolies. This implies the need for different rules for clearing transactions in the CBET market. For example, in a country with a formal wholesale market, the prices paid for net imports could be less than the price of energy in the domestic market or price paid to exports could be greater than the price of energy in the domestic market. For the case of a BBIN country with a vertically- integrated monopoly industry structure, these costs and revenues can be netted against the monopoly's revenue requirement in setting the retail rate.

Applying this same approach to the countries with formal short-term wholesale markets implies that the net costs of the country participating in the BBIN CBET market could be recovered from all customers in the domestic market through a per MWh charge or credit to the extent the country is a net buyer or net seller in the BBIN CBET market. However, there are many other ways that the costs and benefits of a country participating in the CBET market can be recovered from domestic consumers and producers.

## 6. Concluding remarks

A cost-based CBET for the BBIN have the potential to deliver significant economic benefits to the region because of the diversity of energy sources that exist in the region, the large untapped hydroelectric potential in Nepal and Bhutan, the differences in country-level seasonal and hourly load shapes in the region, and the existence of transmission capacity between India and each of these countries in the region.

The potential for exercise of significant unilateral market power by suppliers in an offer-based CBET strongly argues in favor of a cost-based market where the market operator and country-specific regulators formulate transparent rules for determining variable cost of all thermal generation units and opportunity cost of water for all hydroelectric energy. This market will employ a locational marginal pricing to simultaneously sets prices and net imports and exports for each country in the BBIN for all 24 hours of the next day. This will produce potentially different prices in each country for each hour of the day.

The net import and export schedules that emerge from the CBET market will be treated as firm energy import and exports in each hour of the following day and paid or charged the price set for that hour in the day-ahead CBET market. Individual countries will be responsible for managing any additional cost associated with paying these prices for net imports and charging these prices for net exports.

Until all countries in the BBIN region transition to offer-based short-term markets, the increased risk of the exercise of market power in an offer-based CBET market strongly argue against its implementation.

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