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South Asia Sub Regional Economic Cooperation Cross-Border Power Trade Development
(Financed by the Regional Cooperation Integration Fund)

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Final Report: South Asia Sub-regional Economic Cooperation Cross-Border Power Trade Development

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1 Executive Summary

This report presents the findings of the study carried out to meet the requirements and facilitate investigations for the 'South Asia Sub-regional Economic Cooperation (SASEC) Cross-Border Power Trade Development' project, as outlined in the Asian Development Bank (ADB) document with project ID number 47107-001 and carried out under TA-8619.

The main objective of this project is to identify the most economical cross-border power transmission options along with the selected power generation development plans. For example, Nepal, Bhutan and certain regions of India have hydro power availability for potential future development. Bangladesh and certain other regions of India are particularly in need of additional electrical power to meet the future demand. Further development of cross-border power transmission facilities in the South Asia region is warranted against this backdrop. The consultants, in discussion with the power system experts of individual countries, have identified potential cross border interconnections. These interconnections were further analyzed based on their economic merit, provided that the technical criteria are satisfied.

The planning period that was specified for this study is from 2014 to 2030. However, the planning period for the study has been adjusted to 2020 to 2030, considering the project implementation commitments already made by the countries involved and also the time that will be taken to implement projects as a result of the study outcome.

Cross-Border Transmission Links:

There are a number of existing cross-border links connecting different countries in the region. Also, there are several planned cross-border links that are expected to be commissioned in the immediate future.

In addition to the above, an initial list of candidate (potential) cross-border links was prepared using a number of reports (by the involved agents) which suggested possible locations and technologies. The initial list of candidate projects can be found in Appendix E - Master List of Cross-Border Connections.

Subsequently, the list of candidate projects was modified and shortlisted to eight (8) projects. The criteria for filtering the candidate projects were as following:

- Existence of a generation Power Development Agreement (PDA) that justify construction;
- Updated information received from power system authorities of the respective countries.

Moreover, transmission lines that are planned to be commissioned before 2020 are not considered in the final list, as those projects are most likely to have financial closure.

The following candidate cross-border links are identified for the analysis:

1. Rangia/Rowta (India) - Barapukuria (Bangladesh) – Gurudaspur (India);
2. Bareilly (India) - Upper Karnali (Nepal);
3. Gorakhpur (India) - Marsyangdi (Nepal);
4. Rangia/Rowta (India) - Yangbari (Bhutan);
5. Madurai (India) - New Anuradhapura (Sri Lanka);

6. Amritsar (India) - Lahore (Pakistan);
7. Arghandi (Afghanistan) – Peshawar (Pakistan);
8. Rogun (Tajikistan) – Peshawar (Pakistan).

The above cross-border transmission links were identified in collaboration with the experts of each country after considering a number of other cross-border transmission links.

1.1 Results of Interconnected Study Cases

The above list of cross-border transmission links is studied for the study period of 2020-2030. The cases were developed, and the results were obtained based on the following procedure:

- Two regional power system models representing the years 2022 and 2027 were developed by including the variation in transmission topology, generation and load within the study period.
- Using the developed study models of 2022 and 2027, regional power system models were derived for the years 2020 and 2025, considering the transmission topology, load variation and major generation resources in each country.
- The daily optimal costs of operation were obtained for each season and year, using the base regional model, as well as after inclusion of each cross-border transmission link. The Multi-Period DC Optimum Power Flow (MP-DCOPF) program (that is used for calculations) considered the transmission and generation constraints in the regional model. The optimization problem consists of more than 150,000 variables and 600,000 constraints.
- Once the results were obtained for all study years (2020, 2022, 2025, and 2027), they were used to estimate the cost advantage in system operation for the entire study period.
- The cost advantages of study years 2021, 2023 to 2024, 2026, and 2028 to 2030 were assumed to be equal to those for 2020, 2022, 2025 and 2027, respectively, for which system operating cost advantage was calculated using the optimization procedure with and without a particular cross-border connection(s). Those cost advantages were converted to present worth in 2016 using a 10% discount rate.
- Cross border transmission development capital costs were estimated assuming 40 years of life span. Based on that life span assumption, annuitized costs were calculated to obtain the component of those capital costs relevant to the study period.
- The net benefit of a cross-border transmission link for a year in the study period for which an optimization was done was calculated by subtracting the annuitized component of capital cost of that cross-border transmission link from the system operating cost advantage for that year (both present valued to 2016).

In addition, a number of sensitivity scenarios were studied considering different combinations of cross-border power transfer projects, different load growth (in the case of Bangladesh) and different generation development scenarios. Benefit-cost ratios for the cross-border links that were examined have been identified along with related quantitative and qualitative analysis to form a basis for long-term regional transmission planning. A summary of the studied cases and scenarios is presented below.

1.1.1 India – Nepal Cross-border Transmission Links (IN1 and IN2)

- IN1 – Connection between Gorakhpur in North India to Marsyangdi in Nepal (400 kV, 1000 MW)
- IN2 – Connection from Bareilly in North India to Upper Karnali in Nepal (400 kV, 600 MW)

IN1 – Gorakhpur to Marsyangdi

The inclusion of the Gorakhpur-Marsyangdi (IN1) interconnection reduces the total cost of operation of the regional network by $2003 million[1] (present worth) for the entire study period (2020 - 2030). The results indicate that the cost advantage is mainly due to the replacement of higher cost coal-based power generation in Northern India by hydro power in Nepal. The estimated transmission development cost to be recovered within the study period is $280 million, which indicates an approximate benefit of $1723 million. The study reveals that the cross-border transmission link is heavily utilized throughout the study period (loading varies from 70% to 90%).

IN2 - Bareilly to Upper Karnali

Nepal power system network data before 2025 do not include high voltage connections to Upper Karnali, and there are no large generators in the vicinity. Therefore, Bareilly to Upper Karnali (IN2) interconnection is studied for the 2025-2030 period.

The inclusion of the Bareilly-Upper Karnali (IN2) interconnection reduces the total cost of operation of the regional network by $1323 million for the studied period (2025 - 2030). The results indicate that the cost advantage is mainly due to the replacement of higher cost coal-based power generation in Northern and Western India by hydro power in Nepal. The estimated transmission development cost to be recovered within the study period is $82 million, which indicates an approximate benefit of $1241 Million. The study reveals that the cross-border transmission link is heavily utilized throughout the study period (average loading varies from 95% to 100%).

1.1.2 India – Sri Lanka Cross-border Transmission Link (ISL)

ISL – Connection between Madurai to Anuradhapura (500 MW HVDC cross-border transmission link)

The inclusion of the Madurai-Anuradhapura (ISL) cross-border transmission link reduces the total cost of operation of the regional network by $750 million (present worth) for the entire study period (2020 - 2030). The estimated transmission development cost to be recovered within the study period is $255 million, which indicates an approximate benefit of $495 million. The study reveals that the cross-border transmission link is well-utilized throughout the study period (average loading variation from 50% to 90%).

The power flow direction is from India to Sri Lanka in the peak load hours of Sri Lanka, and the direction is reversed in the off-peak hours. The results indicate that the cost advantage

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[1] $ symbol indicates the cost value in US dollars.

is mainly due to the replacement of diesel and coal-based power generation in Sri Lanka by coal based power in India in the peak load period. In the off-peak period, the cost advantage is due to the replacement of gas-based and coal-based power generation in India by coal-based power in Sri Lanka.

1.1.3 India – Bhutan Interconnected Case (IBU)

IBU –Rangia/Rowta and Yangbari (400 kV, 1000 MW)

Rangia/Rowta-Yangbari cross-border transmission link (IBU) reduces the estimated annual cost of operation by $720 million for the entire study period. The estimated transmission development cost to be recovered within the study period is $132 million, which indicates an approximate benefit of $588 million. This cross-border transmission link is lightly-loaded, with an average loading variation of 3% to 40%.

The reasons for the under-utilization of these lines are discussed by examining the existing interconnections, as seen in Figure 1-1.

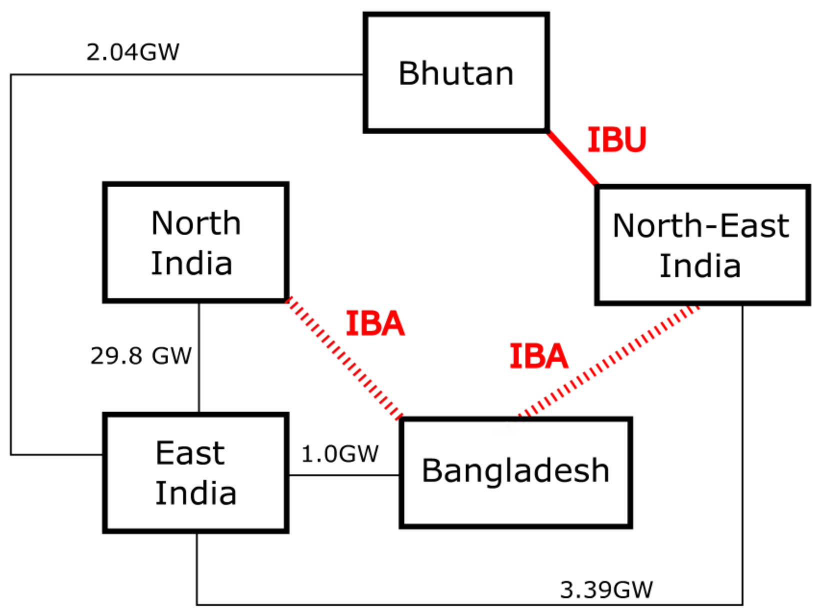

Figure 1-1 : Northern and Eastern India Cross-border Transmission Link for Bhutan

Figure 1-1 shows the interconnection between the Northern and Eastern regions of India with Bhutan and Bangladesh. The black lines represent interconnections between regions of India with the rated transfer capacity. These values are the same for both the 2022 and 2027 study years. The solid red line represents the new Rangia/Rowta-Yangbari interconnection, IBU), and the dashed red line is the potential multi-terminal HVDC transmission link from North-East to Bangladesh to North (IBA).

The main load centers that can be served by Bhutan are located in the Northern region. Therefore, it is desirable to transfer cheaper hydro power from Bhutan (or the North-Eastern region) to the Northern region. The new Bhutan and North-East India connection (IBU in Figure 1-1) has a transfer capacity of 1.1 GW, which could transfer power to hydro-rich North-East India. There are no direct connections between the North-Eastern region and the

Northern region loads. The only connection considered in the cases that can effectively evacuate power from the North-Eastern region to the North is the 800 kV HVDC transmission link between Biswanath (North East)-to-Alipurduar (East)-Agra (North). This connection is utilized fully. Therefore, the additional hydro capacity in Bhutan and North-Eastern region cannot effectively replace the expensive power plants in the Northern region.

There is a prospective HVDC transmission link (IBA Figure 1-1) that is intended to transfer power from North-East to Northern India through Bangladesh. Therefore, Rangia/Rowta-Yangbari connection is studied further when operating in tandem with this new HVDC cross-border transmission link.

1.1.4 North-East India – Bangladesh – North India Interconnected Case (IBA)

The inclusion of the Rangia/Rowta – Barapukuria - Gurdaspur (IBA) cross-border transmission link reduces the total cost of operation of the regional network by $3580 million (present worth) for the entire study period (2020 - 2030). The results indicate that the cost advantage is mainly due to the replacement of higher cost coal-based power generation in the Northern and Western India and gas-based power generation in Bangladesh by hydro power in North-Eastern India. The estimated transmission development cost to be recovered within the study period is $1671 million, which indicates an approximate benefit of $1909 million. The study reveals that the cross-border transmission link is moderately utilized throughout the study period even with its large capacity (loading variation from 30% to 65%). The capacity factors may be improved further by upgrading the transmission network near the terminals of the HVDC transmission line.

1.1.5 India – Pakistan Interconnected Case (IPA)

The inclusion of the Amritsar – Lahore (IPA) cross-border transmission link reduces the total cost of operation of the regional network by $1492 million (present worth) for the entire study period (2020 - 2030). The estimated transmission development cost to be recovered within the study period is $170 million, which indicates an approximate benefit of $1322 million.

The results indicate that the cost advantage in the period before 2025 is mainly due to the replacement of higher cost gas-based power generation in Pakistan by coal based power in Northern India. After 2025, a large number of hydro power plants (e.g. BASHA-1, BASHA-2, BUNJI, etc.) are to be commissioned in Pakistan. Therefore, power transfer direction is reversed, and coal-based power in Northern India is replaced by hydro and coal-based power in Pakistan. The study reveals that the cross-border transmission link is heavily utilized throughout the study period (loading variation from 65% to 100%).

1.1.6 Afghanistan - Pakistan Interconnected Case (AFPA)

The inclusion of the Arghandi - Peshawar (AFPA) cross-border transmission link reduces the total cost of operation of the regional network by $262 million (present worth) for the entire study period (2020 - 2030). The estimated transmission development cost to be recovered within the study period is $247 million, which indicates an approximate benefit of $15 million.

The results indicate that the cost advantage in the period before 2025 is mainly due to the replacement of higher cost gas-based power generation in Pakistan by power import from Turkmenistan through Afghanistan. After 2025, a large number of hydro power plants (e.g. BASHA-1, BASHA-2, BUNJI, etc.) are to be commissioned in Pakistan. Therefore, power transfer direction is reversed, and coal-based power in Afghanistan is replaced by hydro power in Pakistan. The study reveals that the cross-border transmission link is moderately-loaded throughout the study period (loading variation from 20% to 65%). However, the utilization of the cross-border transmission link is slightly reduced in the period after 2025.

1.1.7 Pakistan – Tajikistan Interconnected Case (PATJ)

The inclusion of the Rogun - Peshawar (PATJ) interconnection reduces the total cost of operation of the regional network by $704 million (present worth) for the entire study period (2020 - 2030). The estimated transmission development cost to be recovered within the study period is $420 million, which indicates an approximate benefit of $284 million.

The results indicate that the cost advantage in the period before 2025 is mainly due to the replacement of gas and coal-based power generation in Pakistan by power import from Tajikistan. After 2025, a large number of hydro power plants (e.g. BASHA-1, BASHA-2, BUNJI, etc.) are to be commissioned in Pakistan. Therefore, power import from Tajikistan is greatly reduced after 2025. The study reveals that the transmission link is moderately loaded throughout the study period (loading variation from 10% to 30%). However, the transmission link utilization is reduced in the period after 2025.

1.2 Results of Sensitivity Studies

1.2.1 Development of Both India - Nepal Cross-border Transmission Links (IN12)

The Nepal power system network does not include high-voltage connections to Upper Karnali before 2025, and there are no large generators in the vicinity. Therefore, Bareilly-Upper Karnali (IN2) cross-border transmission link is studied for the 2025-2030 period. This restricts the study of both IN1 and IN2, to the period of 2025-2030.

The inclusion of the Gorakhpur-Marsyangdi (IN1) and Bareilly-Upper Karnali (IN2) cross-border transmission links together reduces the total cost of operation of the regional network by $1853 million for the studied period (2025 - 2030). The results indicate that the cost advantage is mainly due to the replacement of higher cost coal-based power generation in the Northern and Western India by hydro power in Nepal. The estimated transmission development cost to be recovered within the study period is $199 million, which indicates an approximate benefit of $1654 million. The study reveals that both cross-border transmission links are heavily utilized in the 2025-2030 period (average loading variation from 98% to 100%).

1.2.2 Development of North-East India – Bangladesh – North India (IBA) Cross-border Transmission Links with India – Bhutan (IBU) Cross-border Transmission Link - IBABU

The inclusion of the Rangia/Rowta – Barapukuria - Gurdaspur (IBA) cross-border transmission link along with Rangia/Rowta – Yangbari (IBU) cross-border transmission link reduces the total cost of operation of the regional network by $4103 million (present worth) for the entire study period (2020 - 2030). The results indicate that the cost advantage is mainly due to the replacement of higher cost coal-based power generation in the Northern and Western India and gas-based power generation in Bangladesh by hydro power in North-Eastern India and Bhutan. The estimated transmission development cost to be recovered within the study period is $1803 million, which indicates an approximate benefit of $2300 million. The study reveals that both the IBA and IBU cross-border transmission links are utilized more when used in tandem throughout the study period (loading variation from 30% to 65%).

1.2.3 Bangladesh Low Load Forecast Scenario

In this scenario, base, IBA (Rangia/Rowta – Barapukuria – Gurdaspur cross-border transmission link) and IBABU (Rangia/Rowta – Barapukuria – Gurdaspur cross-border transmission link and Rangia/Rowta – Yangbari cross-border transmission link) cases are analyzed assuming a low load growth for Bangladesh. These new cases use the load forecast corresponding to 6% growth.

1.2.3.1 Case with IBA Cross-border Transmission Link

The IBA cross-border transmission link reduces the total cost of operation of the regional network by $1,864 million (present worth) for the entire study period (2020 - 2030). The results indicate that the cost advantage is mainly due to the replacement of higher cost coal-based power generation in the Northern and Western India and gas-based power generation in Bangladesh by hydro power in North-Eastern India. The estimated transmission development cost to be recovered within the study period is $1,671 million, which indicates an approximate benefit of $193 million.

1.2.3.2 Case with IBABU Cross-border Transmission Links (IBA and IBU)

The IBABU cross-border transmission links reduce the total cost of operation of the regional network by $2,505 million (present worth) for the entire study period (2020 - 2030). The results indicate that the cost advantage is mainly due to the replacement of higher cost coal-based power generation in the Northern and Western India and gas-based power generation in Bangladesh by hydro power in North-Eastern India and Bhutan. The estimated transmission development cost to be recovered within the study period is $1,803 million, which indicates an approximate benefit of $703 million.

1.2.4 Utilization Improvement of the IBA Cross-border Transmission Link Scenario

It was observed that the network near Gurdaspur (in Northern India) is strong and capable of handling a transfer of about 5 GW; however, the network near Rangia-Rowta is relatively weak and can be upgraded to facilitate more power transfer through the IBA line. Therefore, the selected transmission lines were upgraded by approximately 300% to observe the improvement of the utilization of the IBA cross-border transmission link. With the upgraded lines, the IBA line reduces the total cost of operation of the regional network by $3,865 million. However, the results indicate a net benefit of $1,964 million for the study period (2020 to 2030). This result is only slightly higher compared to the net benefit of the original IBA project ($1910 million), as the network upgrade costs are also incorporated to this sensitivity analysis. When the IBA cross-border transmission link utilization is compared with and without the internal line upgrades, it can be seen that with the internal line upgrades, the average cross-border transmission link utilization increases from 37.5% to 52.3%.

1.2.5 IBA Cross-border Transmission Link with Bareilly Terminal Scenario

In this scenario, Bangladesh to North India connection was changed from Barapukurita - Gurdaspur to Barapukurita – Bareilly. The results indicate that the IBA line reduces the total cost of operation of the regional network by $3,579 million and produces a net benefit of $1,909 million for the study period (2020 to 2030). In addition, IBA cross-border transmission link is moderately utilized to transfer power from North-Eastern India to Bangladesh in all seasons. Although it shows an increment in the utilization of the cross-border transmission link with the increasing demand in Bangladesh and Northern India, with the new terminal at Bareilly, the IBA line utilization is not significantly improved.

1.2.6 ISL Cross-border Transmission Link with High LNG Penetration in Sri Lanka Scenario

In this scenario, the Sri Lankan power system is modified with a number of natural gas-based power plants which are to be introduced to the Sri Lankan power system according to the "Generation Expansion Plan -2014" by Ceylon Electricity Board (CEB). The results of this sensitivity study indicate that the ISL line reduces the total cost of operation of the regional network by $782 million and produces a net benefit of $526 million for the study period (2020 to 2030). India – Sri Lanka cross-border transmission link is efficiently utilized with an average capacity factor of 73.11% to transfer power from India to Sri Lanka and vice versa in all seasons with new LNG penetration. The main cost advantage is attained as a result of high power transfer from India to Sri Lanka instead of using expensive LNG in Sri Lanka to meet the high demand.

1.2.7 Simultaneous Operation of IBABU and IN12 Cross-Border Transmission Links scenario

In this scenario, the inclusion of India – Nepal transmission links (IN1 and IN2) along with the IBA and IBU cross border transmission links is investigated. The results indicate that the total cost of operation of the network is reduced by $3,850 million for the study period (2025-2030). The estimated transmission development cost to be recovered within the study period is $949 million, which indicates an approximate benefit of $2,901 million. The main cost advantage is attained as a result of the replacement of higher cost coal generation in the Northern and Western India and gas generation in Bangladesh by hydro power in North-Eastern India, Bhutan and Nepal.

1.2.8 All Cross-border Transmission Links Connected Scenario

A scenario with all the cross-border transmission links in service is studied. Economic benefit and the utilization of each cross-border link are investigated for the 2025 to 2030 period, where all cross-border transmission links can potentially be in service. The results of this sensitivity study indicate when all the cross-border transmission links are in service, the total cost of operation of the network is reduced by $3,451 million for the study period (2025-2030). The estimated transmission development cost to be recovered within the study period is $1,404 million, which indicates an approximate benefit of $2,047 million.

1.3 Results Summary

Table 1-1 lists the summary of the individual interconnected cases, as well as sensitivity scenarios.

Table 1-1: Cross-border Transmission Link Power Transfer Results Summary

	Study case	Study period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net benefit ($ millions)	Net benefit/ capital cost for the study period (%)	Average Capacity Factor (%)
Individual Study Cases	IBA	2020-2030	3,580.30	1,670.93	1,909.37	114	37.6
	IBU	2020-2030	719.97	131.7	588.27	446	16.7
	IN1	2020-2030	2,003.02	279.86	1,723.16	615	81.1
	IN2	**2025-2030**	1,323.16	82.25	1,240.90	1507	98.2
	ISL	2020-2030	750.72	255.17	495.56	194	75.1
	IPA	2020-2030	1,492.39	169.97	1,322.42	777	85.4
	AFPA	2020-2030	262.13	246.94	15.2	6	51.8
	PATJ	2020-2030	704	419.79	284.21	67	7.8
Sensitivity Scenarios	IN12	**2025-2030**	1,852.47	198.77	1,653.72	832	100.0/99.2
	IBABU	2020-2030	4,103.17	1,802.63	2300.54	128	46.2/51.1/62.8
	IBA (Low Load)	2020-2030	1,863.94	1,670.93	193.01	12	40.1/30.1
	IBABU (Low Load)	2020-2030	2,505.57	1,802.63	702.95	39	46.1/35.8/60.0
	IBA max	2020-2030	3,864.99	1,901.12	1,963.87	103	52.3%
	IBA Bareilly	2020-2030	3,579.87	1,670.93	1,908.95	114	37.23%
	ISL High LNG	2020-2030	781.52	255.17	526.35	206	73.11%
	IBABU+IN12	**2025-2030**	3,849.85	949.31	2,900.54	306	Refer to section 7.7
	All Links	**2025-2030**	4,342.11	1,403.92	2,938.19	209	Refer to Table 7-50

All cross-border transmission links show a net profit for the study period. North-East India – Bangladesh – North India (IBA), IBABU and IN12 scheme, India – Pakistan (IPA) and India – Nepal (IN1 and IN2) schemes show the highest net benefit.

2 Introduction

2.1 General

The following report outlines the outcome of the study project that was carried out to meet the requirements and facilitate the investigations for the 'South Asia Sub-regional Economic Cooperation (SASEC) Cross-Border Power Trade Development' project, as outlined in the Asian Development Bank (ADB) document with the project ID number 47107-001 and carried out under TA-8619.

The tasks under the TA-8619 (please refer to Appendix J, Sections 22.1 and 22.2 for full Terms of Reference-TOR) expand on the prior activities to develop a comprehensive long-term regional transmission plan for the South-Asia region to align generation and transmission developments of each country considered in this study. (i.e. Afghanistan, Bangladesh, Bhutan, India, Nepal, Pakistan, and Sri Lanka).

Specifically, a comprehensive study of transmission development opportunities that promotes enhanced cross-border electricity trade among South-Asian countries (SASEC members, Afghanistan and Pakistan) was performed, considering identified generation development opportunities. Special attention was given to the transmission interconnection points between India-Nepal, India-Bhutan, India-Bangladesh, India-Sri Lanka, India-Pakistan and Pakistan-Afghanistan. Pakistan and Afghanistan, although non-SASEC member states, were added to the study at a later stage upon the request of SAARC. Examination of the Afghanistan power system was limited to the extent necessary to determine its interconnection impact with the Pakistan power system.

Optimal use of the transmission links between the South-Asian countries, as well as the future interconnections that can maximize cross-border interconnection benefits were studied. The optimal development of electricity generation capacity in the region was used as an input to the regional transmission master plan development. The specified planning period for the study is from year 2020 to year 2030.

2.2 Background

A common procedure for the development of a cross-border generation and transmission link involves the governments of two countries signing a Power Trade Agreement (PTA) or Memorandum of Understanding (MoU), which recognizes the benefits of exchanging power. The second step involves signing of a Power Development Agreement (PDA), which identifies and promotes the development of power generation and the associated transmission infrastructure. If investors (generation companies and utilities) agree on the benefits of the project, they may sign a Power Purchase Agreement (PPA), which establishes a financial contract to sell electricity in the future. The last step before starting the construction is the Financial Closure (FC), which estimates the final cost of the initiative and all financing arrangements, allocates budget for each stage of the project and ensures the disposition of the assets (i.e. land for generation power plants or right of way for transmission lines).

Finally, a Transmission Service Agreement (TSA) is signed, as the power lines and other components of the network are owned by different agents across the border. TSA is an agreement focused on the operation, metering, accounting, charges, losses, billing, etc.

Although the procedure generally follows the chronological order mentioned in the description, it is not always the case. For example, in some cases, a PDA is signed between companies to develop generation and following that, the governments sign a PTA to facilitate the development of the project.

Projects that already have the FC are in the process of construction and have all the details finalized, including transmission facilities for power evacuations. Consequently, potential generation-transmission development projects at the stage of PDA or before are the relevant candidates studied in this project. Any project at the PDA stage or before will take four to five years for construction before being brought into service. Thus, the planning period considered in this study has been adjusted to year 2020 to year 2030 instead of the originally specified planning period of year 2014 to year 2030.

The following procedure was followed during the study:

- A review of power system planning was carried out to get familiar with the state-of-the-art practices, software tools and mathematical techniques. A detailed summary of the review is given in Appendix J - Review of Power System Planning.
- Two regional power system models for the years 2022 and 2027 were developed by including the variation in transmission topology within the study period. Generation capacity and demand in the regional models were adjusted to match the forecasts for the given study years.
- Using the developed study models of 2022 and 2027, regional power system models were derived for the years 2020 and 2025, considering the load variation and major generation resources in each country. The results were obtained by adding each cross-border transmission link to the regional models and evaluating the cost advantages due to optimal re-dispatch. These results provide an insight about the overall feasibility of each link.
- Once the results were obtained for all study years (2020, 2022, 2025 and 2027), they were used to estimate the cost advantage for the entire study period. The economic benefit of each cross-border transmission link was estimated using the cost advantage for the study period and estimated transmission development costs for the corresponding cross-border transmission link.
- In addition, several sensitivity scenarios were studied considering different combinations of cross border power transfer links, different load growths and generation development approaches.
- Cross-border transmission links and scenarios which maximize the cross-border power transfer benefits with higher cost advantage were identified to help developing a comprehensive long-term regional transmission plan.

3 Economic Analysis

This section presents the procedure of the economic analysis performed to estimate the net benefit of each potential cross-border transmission development scheme listed in Section 5.2. Economic analysis procedure consists of three main stages:

1. Pre-processing of raw data available in the form of PSS/E™ power flow data, load forecast, daily load curves, generator costs and long-term generation and transmission planning information.
2. Optimization of daily cost of generation considering the transmission and generation constraints using Multi-Period DC Optimum Power Flow (MP-DCOPF) program.
3. Post-processing of optimum cost of generation along with the transmission investment cost to estimate the net benefit of the potential cross-border transmission link.

3.1 Economic Analysis Procedure

Based on the identified cross-border power transfer projects, a number of cross-border transfer cases are developed based on the following procedure:

- Initially, the base cases are developed for the study years 2022 and 2027. PSS/E cases and planning reports are used to adjust generation, transmission and load. Using the base cases developed for years 2022 and 2027, two more base cases are developed for years 2020 and 2025. The load and major generation resources of each case are adjusted to match the corresponding year. However, in many countries, long-term transmission planning data are not available for all years. Therefore, the transmission system differences in some study years are minimal. The details of the utilized cost function and the generator cost coefficients for each technology are given in Appendix H - Cost of Operation Function and Terms Used For Each Technology.

- All existing and planned (to be commissioned) cross-border transmission links are included in the cases.

- The data from the developed cases are entered to the economic planning software, and initial results are obtained. The cases may show infeasible solutions with the transmission constraints used, as many long-term planning cases do not comply with the necessary transmission upgrade requirements. If such infeasibilities are observed, thermal limits are relaxed, while extra required capacity is charged with a penalty factor (i.e. apply 'soft' thermal limits) to obtain a feasible solution. In this method, it is possible to identify the list of branches which need to be upgraded. These lines are upgraded by adding extra circuits when the required extra capacity is significant (more than 20% overload). If a small upgrade (less than 20% overload) is required, the thermal limit is increased where the upgrade is assumed to be re-tension or re-conductor the lines.

- New case data with the transmission upgrades are entered to the program. The solution may still be infeasible, as the power flow is modified. If so, the previous step is applied iteratively until a feasible solution is reached. By adhering to this method, it is possible to obtain a set of base cases with feasible solutions.

- Each potential cross-border power transfer project is included separately into the cases of 2020, 2022, 2025 and 2027, and their economic impact is analyzed. The results of these years are used to estimate the cost advantage for the entire study period (2020-2030). The cost advantages of study years 2021, 2023 to 2024, 2026, and 2028 to 2030 are assumed to be equal to those for 2020, 2022, 2025 and 2027, respectively, for which the system operating cost advantage has been calculated using the optimization procedure with and without a particular cross-border connection(s). Estimated cost advantages are converted to present worth using a 10% discount rate. By using this method, the present worth of the assumed cost advantages for these years is appropriately captured for the final analysis. The net economic benefit of each cross-border transmission link is estimated using the cost advantage for the study period and estimated transmission development costs for the transmission link.

- In addition, several sensitivity scenarios are studied considering different combinations of cross-border power transfer projects, different load growths and generation development approaches. Cross-border transmission links and scenarios which maximize the cross-border transfer benefits with high cost advantage are identified to expand on in a comprehensive long-term regional transmission plan.

3.1.1 Data Requirements

The data requirements for the Economic analysis are presented in Table 3-1. These data items are required to obtain an accurate network model and a feasible solution.

Table 3-1: Data Requirements

Data Requirement
Load
- Yearly (maximum) load forecast for all years in the study period
- Shape of the daily load curve for a representative day of each season
Generation
- Location, Voltage level
- Active power limits (Pmax, Pmin)
- Fuel Type
- Availability (seasonal)
- Fuel cost or price of active power
- Commissioning/retirement date
Transmission Network
- Location, voltage level
- # of circuits
- Series Reactance
- Continuous Thermal Rating
- Phase shift angle (for transformers)
- Commissioning/retirement date

3.1.2 Ranking Criteria for Cross-border Transmission Links

As there are number of planning cases and scenarios, one requires a criterion to rank the studied cross-border transmission links and identify the total economic benefit. The following relationships are used to estimate the expected economic benefit for a given cross-border transmission link and the planning period (i.e. 2020 to 2030).

$$\begin{matrix} \text{Expected cost advantage} \\ \text{due to the} \\ \text{cross border power transfer} \end{matrix} = \begin{Bmatrix} \text{Expected operating cost} \\ \text{without the cross border} \\ \text{power transfer} \end{Bmatrix} - \begin{Bmatrix} \text{Expected operating cost} \\ \text{with the cross border} \\ \text{power transfer} \end{Bmatrix}$$

$$\begin{matrix} \text{Total expected} \\ \text{economic benefit} \end{matrix} = \begin{Bmatrix} \text{Expected cost advantage} \\ \text{due to the} \\ \text{cross border power transfer} \end{Bmatrix} - \begin{Bmatrix} \text{Expected cost of transmission} \\ \text{adjusted to the study period} \end{Bmatrix}$$

Cases and scenarios with the highest economic benefit for the region are selected to undergo a detailed analysis for future development.

3.2 Economic Planning Software Program

Transmission upgrade costs can be directly calculated once the required upgrades are identified. The cost of operation for the study period is more difficult to calculate.

The Multi-Period DC Optimal Power Flow (MP-DCOPF) program has been developed to calculate the expected costs of operation for a given scenario. The program calculates the minimum cost of operation for a given daily load pattern; the load pattern must be discretized for this calculation (as shown in Figure 3-1).

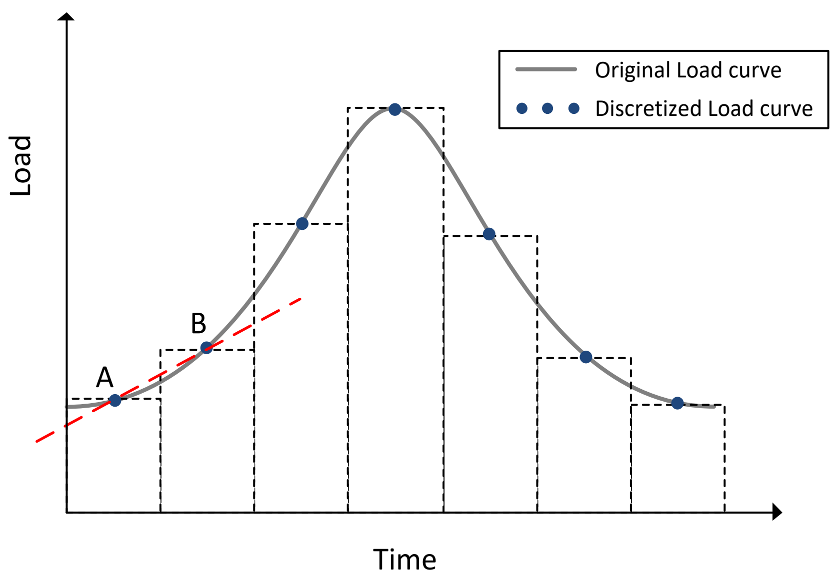

Figure 3-1: Approximation of Load vs. Time Curve with Discrete Load Values

The load curve is discretized into 24 periods, representing each hour of a day.

The MP-DCOPF program optimizes the total cost of operation considering the entire load pattern for a given day, generators available for dispatch, and the cost of generation. The network solution for each discrete load point is obtained using classical linear 'DC Power Flow' assumptions. The primary outputs of the main program are units committed, the dispatch of the committed units and cost of generation for each discrete point on the load curve for entire day.

The following section provides a summary of features and capabilities of the MP-DCOPF program.

3.2.1 Features

The following are the main features of the MP-DCOPF program:

- Multi-period DC Optimal Power flow solution:
    - The program solves the DC power flow for a number of periods that can be defined by the user. Ramp rates of all generators are taken into account when evaluating the multi-period DC power flow solution.
- Cost of operation evaluation:
    - The program supports both quadratic and linear cost of operation functions.
- Daily variation of renewable generator capacity:
    - The maximum active power that a renewable power generator can deliver can vary in each period. The program can handle period-specific maximum power for each renewable generator. This feature facilitates accurate modelling of solar and wind power plants.
- Handling of infeasible solutions due to thermal constraints:
    - Many long-term planning cases show congestions in the transmission network, as all the upgrade requirements are not identified (typically, only the most important upgrades are identified many years ahead of the actual operation). If such cases are identified in DCOPF programs, solution space defined by thermal constraints becomes infeasible. In these situations, the program automatically relaxes thermal limits, while the extra capacity required to obtain a feasible solution is charged with a penalty factor (i.e. apply 'soft' thermal limits). Figure 3-2 demonstrates the application of penalty factors in the program. This feature makes it possible to identify the list of lines which need to be upgraded.

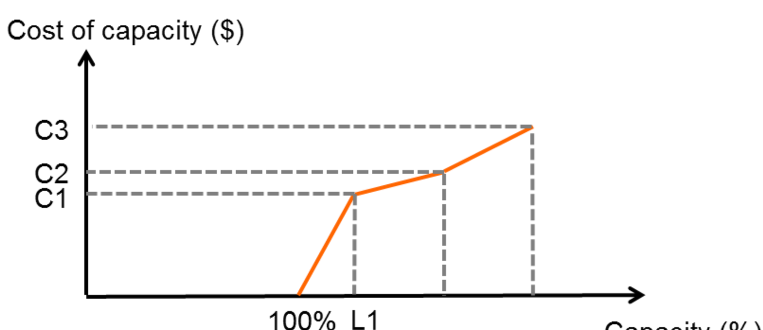

Figure 3-2: Application of Penalty Factors for Extra Transmission Capacity

- Selection of a subset of thermal constraints:
    - A subset of thermal constraints can be selected to be applied. This is beneficial when excluding the thermal constraints of the low-voltage network or a specific region.
- Optimization of selected generators:
    - A subset of the generators can be included in the objective function, such that the rest of the generators are dispatched at a specified value.

The availability of different types of generation in each season is considered in the optimization by calculating seasonal effective power limit (Seasonal Pmax) using the actual power limit of the generator unit and the generator availability data.

3.2.2 Inputs

- Transmission line reactance, thermal limits, penalty factors (to avoid infeasibilities due to line limits);
- Load values, load curves and locations;
- Generation locations, limits (dynamic limits for renewables), generation pricing data and ramp rates.

3.2.3 Outputs

- Generation dispatch corresponding to each load pattern;
- Cost of operation for each set of load patterns representing a day;
- Transmission lines at thermal limit and available transmission capacity (ATC);
- List of transmission lines which exceed the thermal limits (to obtain a feasible solution).

3.2.4 Constraints

The following constraints are to be met when executing the algorithm:

- Active power balance;
- Generator power ramp rate limits;
- Generator active power limits;
- Transmission line continuous thermal limits.

3.2.5 Objective Function

The objective function (linear or quadratic) of the summation of the cost of all generation is minimized to determine the optimal daily generation corresponding to a given daily load pattern. If the solution is not feasible due to thermal constraints, objective function is extended to include extra capacity required in the transmission system.

3.2.5.1 Performance

The program is capable of handling a large regional network in excess of 6,000 buses, 1,000 generator units, 10,000 branches, and 30 HVDC lines. Optimization calculations for a single day (24 load patterns) take a few minutes. In addition, a large number of generator units and thermal constraints corresponding to branches can be removed[2] from the optimization process, while they are represented in the power flow calculation. This will reduce the calculation time for load patterns corresponding to one day to several seconds.

[2] Thermal constrains of selected high voltage transmission lines (e.g. 400 kV and above for most of India) can be included in the optimization process. Similarly, large generator units impacting the power transfer can be selected for the optimization.

4 Power System Outline

The power system overview of each country is presented in Appendix A - Power System Overview. The load, generation and transmission data are organized by country for years 2022 and 2027.

4.1 Load Data

The collected load data include the load forecasts extracted from the power system planning reports of each country and the PSS/E simulation cases. The daily load curves (Appendix D - Daily Load Curves) for each season, which represents the daily behaviour of individual load in the economic model, are also collected.

4.2 Generation Data

The generation data consist of the total capacity of generation for the study years, the generation mix, and the availability factors. The total capacity of the generation has been calculated using the PSS/E simulation cases as a starting point. The generation in the cases has been modified to include future power plants that are relevant to the study. The cases have also been modified when the generation retirement plans are available from planning reports. The PSS/E simulation cases do not have information about the technology for each generator. Thus, a mapping process of the PSS/E generation with acquired information from power system planning reports and internet data bases [8], [9] has been carried out.

The availability factor of a generator represents its possibility of utilization during a given season. Whether the generator is actually utilized or not is irrelevant. Typical availability factors are used for each generation technology when reasonable availability factors are not available. If the assumed availability factors violate the power balance constraint in a given country, those are modified until a feasible solution is found.

4.3 Transmission Data

The transmission system data have been obtained using the PSS/E cases. If the PSS/E case that represents the year of the study is not available, the available case year closest to the study year has been used. In those situations, the case is updated by adding high voltage transmission links with known commissioning dates (if any) to represent the correct transmission system.

5 Existing, Planned and Potential Cross-border Transmission Links

5.1 Existing or Planned Cross-border Transmission Links

This section lists the transmission lines that already connect countries in the sub-continent and future cross-border transmission links to be commissioned. The commissioning of these future projects has a very low uncertainty. Thus, they have been included in the model, although in some cases the transmission links are considered out of service.

The existing or planned cross-border transmission links are listed below.

5.1.1 India-Bhutan

The following transmission links are added to the model as new additions for the period of study (2020-2030):

- Alipurduar (India) – Tala (Bhutan). The cross-border transmission link consists of 2 circuits operating to 400 kV with a total transfer capability of 1100 MVA. These links are not in service.
- Siliguri (India) – Tala (Bhutan). The cross-border transmission link consists of 2 circuits operating to 400 kV with a total transfer capability of 1100 MVA.
- Siliguri (India) – Wangchu (Bhutan). The cross-border transmission link consists of 1 circuit operating to 400 kV with a total transfer capability of 550 MVA.
- Siliguri (India) – Malebase (Bhutan). The cross-border transmission link consists of 1 circuit operating to 400 kV with a total transfer capability of 550 MVA.
- Alipurduar (India) – Punatsanc (Bhutan). The cross-border transmission link consists of 4 circuits operating to 400 kV with a total transfer capability of 2588 MVA.
- Alipurduar (India) – Jimeling (Bhutan). The cross-border transmission link consists of 2 circuits operating to 400 kV with a total transfer capability of 1300 MVA.

5.1.2 India – Bangladesh

The following cross-border transmission link has been identified as already in operation:

- Barhampur (India) – Bheramara (Bangladesh). It is an HVDC link with a total transfer capability of 1000 MVA.

5.1.3 India – Nepal

The following cross-border transmission link has been identified as already in operation:

- Muzaffarpur (India) – Dhalkebar (Nepal). The link consists of 1 circuits operating to 400 kV with a total transfer capability of 1000 MVA.

5.1.4 India – Sri Lanka

There is no existing cross-border transmission link between these two countries.

5.1.5 India – Pakistan

There is no existing cross-border transmission link between these two countries.

5.1.6 Pakistan – Afghanistan

There is no existing cross-border transmission link between these two countries.

5.2 Potential Cross-border Transmission Links

The following sub-section provides a brief account of each possible cross-border transmission link. The initial list of future cross-border transmission link candidates is prepared using a number of reports (by the involved agents) that suggested possible locations and technologies. The initial list of candidate projects can be found in Appendix E - Master List of Cross-Border Connections.

Subsequently, the list of candidate projects was modified and shortlisted to eight (8) projects. The criteria for filtering the candidate projects are as following:

- Existence of generation PDA that justify the construction;
- Information received from power system authorities of the respective countries.

The list of potential projects is as follows:

Id codification: I=India, BA=Bangladesh, BU=Bhutan, N=Nepal, AF=Afghanistan, PA=Pakistan, TJ=Tajikistan.

- IBA: Rangia/Rowta (India) - Barapukuria (Bangladesh) – Gurdaspur (India)
  - Technology: Multi-terminal HVDC system
  - Voltage Level: ±800 kV
  - Rating: 6000 MW- a 500 MW/1000 MW HVDC terminal in Barapukuria will be used for drawing power to Bangladesh

- IN1: Gorakhpur (India) - Marsyangdi (Nepal)
  - Technology: AC double circuit
  - Voltage Level: 400kV
  - Rating: 1000 MW

- IN2: Bareilly (India) - Upper Karnali (Nepal)
  - Technology: AC double circuit
  - Voltage Level: 400kV
  - Rating: Not confirmed

- IBU: Rangia/Rowta (India) - Yangbari (Bhutan)
  - Technology: AC double circuit
  - Voltage Level: 400kV
  - Rating: 1000 MW

- ISL: Madurai (India) - New Anuradhapura (Sri Lanka)
  - Technology: HVDC bipole
  - Voltage Level: 400kV
  - Rating: 500 MW

- IPA: Amritsar (India) - Lahore (Pakistan)
  - Technology: AC Quad double circuit, and back-to-back HVDC converter at Lahore terminal.
  - Voltage Level: 400 kV
  - Rating: 1000 MW

- AFPA: Arghandi (Afganistan) – Jalalabad (Afganistan) – Peshawar (Pakistan)
  - Technology: HVDC
  - Voltage Level: 500 kV
  - Rating: 1000-1300 MW

- PATJ: Rogun (Tajikistan) – Peshawar (Pakistan)
  - Technology: HVDC
  - Voltage Level: 500 kV
  - Rating: 1000MW

Figure 5-1 depicts the list of transmission links above. Candidate cross-border transmission links are marked in red, whereas existing and planned cross-border transmission links are marked in black.

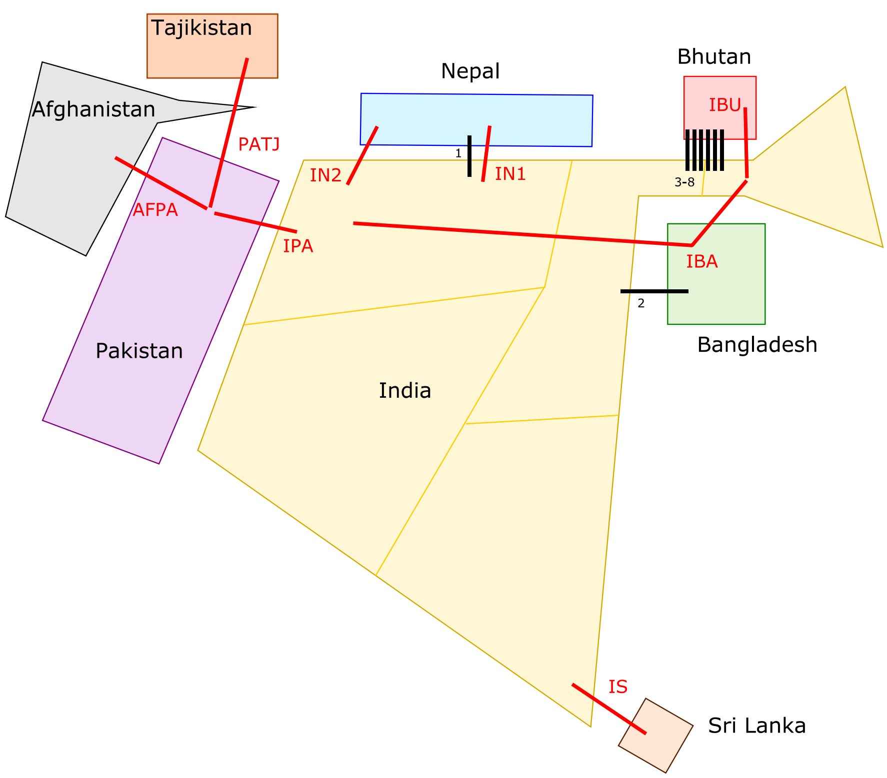

Figure 5-1: Schematic Map of the Proposed Cross-Border Transmission Links

Appendix E - Master List of Cross-Border Connections provides a description of the filtered candidate projects, including the possible locations of 'sending' and 'receiving' line ends, technology, voltage level, associated generators and loads, cost estimation, and remarks.

6 Study Results: Individual Cross-Border Transmission Links

This chapter presents the net benefit of each potential cross-border transmission link and related calculations.

First, the daily costs of operation for the base regional models without potential cross-border transmission links (for all four seasons in years 2020, 2022, 2025 and 2027) were estimated. These base regional models were created using the updated power flow cases of individual country (based on planning reports) and the existing and planned (to be commissioned) cross-border transmission links. Loads were adjusted based on the seasonal daily curves to obtain the model for each season.

Base regional models without potential cross-border transmission links showed a number of transmission congestions, resulting in infeasible solutions in the optimization process. This was due to the fact that only the major transmission expansion upgrades for individual countries were available for the study period. In order to obtain a feasible solution, a number of transmission line upgrades were identified, based on the procedure explained in Section 3. These upgrades were assumed to be required independent of the studied candidate cross-border transmission links. Following that, the estimated daily and annual costs, as well as the average dispatch of generators in each individual country for the corrected base regional model were calculated.

Secondly, the cases containing each individual cross-border transmission link were optimized, and a daily cost of operation and an annual cost advantage were determined in comparison with the base regional case. The net benefit of each potential cross-border transmission link was obtained using the cost advantage of the cross-border transmission link during the studied period and the annuitized capital cost of the transmission link for the study period. In addition, utilization of the cross-border transmission link was presented using the peak power transfer and a capacity factor. In addition, major dispatch changes compared to the base cases were reported, which contributed to the reduction in operating cost.

6.1 Presentation of Results

The following points summarize different measurements that were taken into account to compare the cases:

- The daily cost of operation, which is the output of the optimized models for study years 2020, 2022, 2025 and 2027. These values represent the daily cost of operation for one typical day of each season of the given year.
- The annual costs of operation are calculated using the four (4) daily costs of operation for four seasons[3] (summer, winter, monsoon and post-monsoon) of the year.
- The cost advantage is the difference between the annual cost of operation of the interconnected case and the base case. Annual cost advantages for years 2020, 2022, 2025 and 2027 are used to obtain the total cost advantage for the study

[3] Each season is assumed to have equal duration (3 months)

period from year 2020 to 2030. The cost advantages of study years 2021, 2023 to 2024, 2026, and 2028 to 2030 are assumed to be equal to those for 2020, 2022, 2025 and 2027, respectively, for which system operating cost advantage was calculated using the optimization procedure with and without a particular cross-border transmission link(s). Those cost advantages are converted to present worth in 2016 using a 10% discount rate.

- The costs of cross-border transmission links are estimated (construction, engineering and other cost associated with the project) based on projects with comparable ratings. A description of the project costs is given in Appendix G – Transmission Cross-Border Capital Cost Estimations Cross-border transmission development capital costs are estimated assuming 40 years of life span. Based on this life span assumption, annuitized costs are calculated to obtain the component of those capital costs relevant to the study period.
- The net benefit of a cross-border transmission link for a year in the study period, for which an optimization is done, is calculated by subtracting the annuitized component of the capital cost of that transmission link from the system operating cost advantage for that year (both present valued to 2016).
- The daily average generation dispatch is obtained for each season for the base case. In cross-border study cases, only major generation changes, which are influenced by the cross-border transmission link, are shown.
- Interconnection loading:
  - Maximum loading, as well as the direction of the power flow, are discussed.
  - To evaluate the utilization of the interconnection throughout the 24-hour period, a capacity factor is defined as follows:
    - Capacity factor for a given transmission line TL, $C_{TL}=\frac{\sum_{i=1}^{24} P_{TL,i}}{(24 \cdot S_{TL,max})}$, where, $P_{TL,i}$ is the line flow in the ith period and S_{TLmax} is the thermal limit.
- Size of the optimization problem:
  - The regional base case consists of more than 6,000 buses, 700 plants and 13,000 branches, which result in a significant and challenging optimization problem. Table 6-1 shows the details of the optimization problem using the 2022 summer base case.

Table 6-1: Size of the Optimization Problem (2022 Summer Base Case)

Parameter		Number
Variables		165864
Constraints	Equality	139656
	Inequality	488876
	Total	628532
Objectives		1

6.2 South Asia Regional Base Case

The base regional cases represent the future power system of Afghanistan, Bhutan, Bangladesh, India, Nepal, Pakistan and Sri Lanka. In these cases, only the existing and planned (to be commissioned) cross-border transmission links are included. Thus, if there are no existing or planned transmission links which connect a specific country with the rest of the South Asia continent, that country operates as a separate island within the case (e.g. Sri Lanka).

6.2.1 Cost of Operation

Table 6-2 illustrates the seasonal daily costs of operation and annual cost of operation of the base cases for each year.

Table 6-2: Cost of Operation for the Base Cases

Year	Daily cost of operation for the regional base case ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	167.19	161.73	165.54	157.57	59,498.21
2022	191.36	184.61	189.77	180.33	68,078.85
2025	206.64	197.51	209.91	198.34	74,131.61
2027	240.06	227.93	239.26	224.94	85,063.48

As the load in each year increases, it can be observed that the estimated cost of operation also increases accordingly.

6.2.2 Generation Dispatch

Table 6-3 illustrates the average generation dispatch of Afghanistan in all four seasons of each year. It can be observed that the imports from Uzbekistan, Tajikistan and Turkmenistan are not required with the development of coal-based and hydro power generation after 2025.

Table 6-3: Base Case Generation Dispatch (Daily Average) for Afghanistan

Year	Season	Technology (MW)				
		Coal	Gas	Diesel	Hydro	Import
2020	Summer	0.0	10.9	82.3	44.1	821.1
	Winter	0.0	13.4	78.6	41.0	900.3
	Monsoon	0.0	14.5	84.0	53.6	632.2
	Post-Monsoon	0.0	37.7	71.2	50.4	726.9
2022	Summer	0.0	24.0	77.6	44.1	1067.3
	Winter	0.0	25.2	72.8	41.0	1145.7
	Monsoon	0.0	19.6	83.9	53.6	869.4
	Post-Monsoon	0.0	0.0	0.0	50.4	1007.2
2025	Summer	66.8	0.0	0.0	1371.2	0.0
	Winter	66.8	0.0	0.0	1371.2	0.0
	Monsoon	66.8	0.0	0.0	1371.2	0.0
	Post-Monsoon	66.8	0.0	0.0	1371.2	0.0
2027	Summer	275.9	0.0	0.0	1371.2	33.5
	Winter	275.9	0.0	0.0	1371.2	33.5
	Monsoon	275.9	0.0	0.0	1371.2	33.5
	Post-Monsoon	275.9	0.0	0.0	1371.2	33.5

Table 6-4 illustrates the average generation dispatch of Bangladesh in different seasons of each study year.

Table 6-4: Base Case Average Generation Dispatch for Bangladesh

Year	Season	Technology (MW)				
		Coal	Gas	Diesel	Hydro	Nuclear
2020	Summer	7338.0	8086.0	936.0	61.4	0.0
	Winter	7063.0	8086.0	936.0	56.3	0.0
	Monsoon	7276.0	8086.0	936.0	78.6	0.0
	Post-Monsoon	7096.0	8087.0	936.0	74.2	0.0
2022	Summer	8660.0	8088.0	936.0	61.4	0.0
	Winter	8206.0	8087.0	936.0	56.3	0.0
	Monsoon	8669.0	8105.0	937.0	78.6	0.0
	Post-Monsoon	8232.0	8088.0	936.0	74.2	0.0
2025	Summer	11580.0	8164.0	936.9	61.4	1816.0
	Winter	11550.0	8160.0	936.8	55.9	1737.0
	Monsoon	11540.0	8169.0	937.0	78.9	1784.0
	Post-Monsoon	11550.0	8160.0	936.9	74.3	1469.0
2027	Summer	11781.0	8340.0	936.8	61.4	1997.0
	Winter	11570.0	8171.0	936.8	56.3	1844.0
	Monsoon	12020.0	8342.0	939.5	79.2	1950.0
	Post-Monsoon	11560.0	8184.0	936.9	74.2	1619.0

Table 6-5 illustrates the average generation dispatch of Bhutan in different seasons of each study year.

Table 6-5: Base Case Average Generation Dispatch for Bhutan

Year	Season	Technology (MW)
		Hydro
2020	Summer	3749.0
	Winter	3159.0
	Monsoon	4581.0
	Post-Monsoon	4519.0
2022	Summer	3774.0
	Winter	3159.0
	Monsoon	4607.0
	Post-Monsoon	4474.0
2025	Summer	3769.0
	Winter	3097.0
	Monsoon	4582.0
	Post-Monsoon	4446.0
2027	Summer	3746.0
	Winter	3096.0
	Monsoon	4709.0
	Post-Monsoon	4451.0

Table 6-6 illustrates the average generation dispatch of Nepal in different seasons of each study year.

Table 6-6: Based Case Generation Dispatch for Nepal

Year	Season	Technology (MW)
		Hydro
2020	Summer	1983.0
	Winter	1949.0
	Monsoon	2117.0
	Post-Monsoon	2020.0
2022	Summer	2219.0
	Winter	2181.0
	Monsoon	2402.0
	Post-Monsoon	2273.0
2025	Summer	3924.0
	Winter	3871.0
	Monsoon	4166.0
	Post-	4075.0

Year	Season	Technology (MW)
		Hydro
	Monsoon	
2027	Summer	4088.0
	Winter	4017.0
	Monsoon	4395.0
	Post-Monsoon	4158.0

Table 6-7 illustrates the average generation dispatch of India in different seasons of each study year.

Table 6-7: Based Case Generation Dispatch for India

Year	Season	Technology (MW)					
		Coal	Gas	Diesel	Hydro	Nuclear	Wind/Solar
2020	Summer	130400.0	2726.0	22.2	33020.0	7492.0	1440.0
	Winter	124300.0	2638.0	37.5	25440.0	7495.0	0.0
	Monsoon	131600.0	2542.0	18.9	34370.0	7498.0	1620.0
	Post-Monsoon	120900.0	2832.0	32.7	31690.0	7499.0	1620.0
2022	Summer	151600.0	3766.0	30.2	33260.0	7492.0	1440.0
	Winter	106070.0	5032.0	57.4	20399.0	3675.0	0.0
	Monsoon	152740.0	3732.0	24.8	34598.0	7491.0	1620.0
	Post-Monsoon	140720.0	4173.0	32.8	31820.0	7498.0	1620.0
2025	Summer	177300.0	5524.0	42.7	36710.0	9200.0	2293.0
	Winter	167400.0	4732.0	81.2	29020.0	9191.0	0.0
	Monsoon	178800.0	5245.0	38.7	38290.0	9200.0	2527.0
	Post-Monsoon	164300.0	5673.0	75.2	35220.0	9200.0	2527.0
2027	Summer	206710.0	7228.0	43.1	37210.0	9200.0	2293.0
	Winter	194770.0	5563.0	81.8	28945.0	9200.0	0.0
	Monsoon	208150.0	7221.0	74.2	38400.0	9200.0	2527.0
	Post-Monsoon	192910.0	7293.0	58.2	35270.0	9200.0	2527.0

Table 6-8 illustrates the average generation dispatch of Pakistan in different seasons of each study year.

Table 6-8: Based Case Generation Dispatch for Pakistan

Year	Season	Technology (MW)					
		Coal	Gas	Diesel	Hydro	Nuclear	Wind/Solar
2020	Summer	14500.0	4352.0	780.0	10780.0	67.5	423.1
	Winter	15380.0	4538.0	780.0	10060.0	63.0	0.0
	Monsoon	12710.0	3936.0	780.0	12940.0	81.0	634.6
	Post-Monsoon	13010.0	4528.0	801.4	12220.0	76.5	634.6
2022	Summer	15090.0	4688.0	780.0	11200.0	970	423.1
	Winter	15800.0	5073.0	780.0	10460.0	965.5	0.0
	Monsoon	13450.0	4044.0	780.0	13440.0	983.5	634.6
	Post-Monsoon	13440.0	4846.0	780.0	12700.0	836.5	634.6
2025	Summer	9240.0	4560.0	730.0	27770.0	1418.0	423.1
	Winter	9944.0	4560.0	730.0	27370.0	1531.0	0.0
	Monsoon	11698.0	4652.0	730.0	25010.0	1848.0	634.6
	Post-Monsoon	11185.0	5319.0	734.6	25100.0	1606.0	634.6
2027	Summer	11420.0	4882.0	730.0	30370.0	1752.5	423.1
	Winter	12630.0	5595.0	730.0	28786.0	1831.0	0.0
	Monsoon	9138.0	4560.0	730.0	33100.0	1414.0	634.6
	Post-Monsoon	9490.0	4516.0	730.0	32830.0	1379.0	634.6

Table 6-9 illustrates the average generation dispatch of Sri Lanka in different seasons of each study year.

Table 6-9: Based Case Generation Dispatch for Sri Lanka

Year	Season	Technology (MW)			
		Coal	Diesel	Hydro	Wind/Solar
2020	Summer	799.8	4.8	1481.0	200.6
	Winter	799.8	4.8	1481.0	200.6
	Monsoon	563.1	0.9	1721.0	200.6
	Post-Monsoon	642.2	0.9	1644.0	198.8
2022	Summer	1006.0	9.6	1486.5	200.6
	Winter	1006.0	9.6	1486.5	200.6
	Monsoon	749.2	0.9	1752.0	200.6
	Post-Monsoon	829.0	0.9	1672.0	200.6
2025	Summer	1440.0	0.9	1616.0	269.0
	Winter	1440.0	0.9	1616.0	269.0
	Monsoon	1120.0	0.9	1936.0	269.0
	Post-	1224.0	0.9	1832.0	269.0

Year	Season	Technology (MW)			
		Coal	Diesel	Hydro	Wind/Solar
	Monsoon				
2027	Summer	1555.0	4.1	1616.1	269.0
	Winter	1555.0	4.2	1616.0	268.9
	Monsoon	1235.0	0.9	1939.0	269.0
	Post-Monsoon	1343.0	0.9	1832.0	269.0

6.2.3 Impact on Existing Power Transmission Lines

Table 6-10 shows the number of upgraded transmission lines to obtain a feasible solution for the base case in each study year. These lines are upgraded by adding parallel lines when the required extra capacity is significant (more than 20% overload). If a minor upgrade (less than 20% overload) is required, the thermal limit is increased, assuming simple mitigations, such as re-tensioning of conductor or replacing a current transformer, are sufficient. The procedure of obtaining a feasible solution with line upgrades is explained in Section 3.1.

Table 6-10: The Number of Transmission Lines That Have to Be Upgraded to Make the Model Feasible

Year	Number of upgraded lines
2020	478
2022	424
2025	741
2027	781

6.3 Case Results for Individual Cross-border Transmission Links

The following section presents the results of the economic analysis of the cases containing each individual cross-border transmission link. Reported results include the daily cost of operation, the annual cost advantage, net benefit of the project, utilization of the cross-border transmission link, and the major dispatch changes.

6.3.1 North-East India – Bangladesh – North India (Rangia/Rowta – Barapukuria - Bareilly) Interconnected Case (IBA)

6.3.1.1 Cost of Operation

Table 6-11 and Figure 6-1 present the daily and annual costs of operation with the India-Bangladesh cross-border transmission link for each season of the studied years.

Table 6-11: Daily and Annual Cost Of Operation with the Cross-Border Transmission Link

Year	Daily cost of operation with the cross-border transmission link ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	165.59	161.09	164.10	156.09	59,027.2
2022	189.91	183.94	188.51	179.04	67,651.7
2025	203.63	195.96	204.62	191.74	72,631.7
2027	237.28	226.66	236.47	222.00	84,169.8

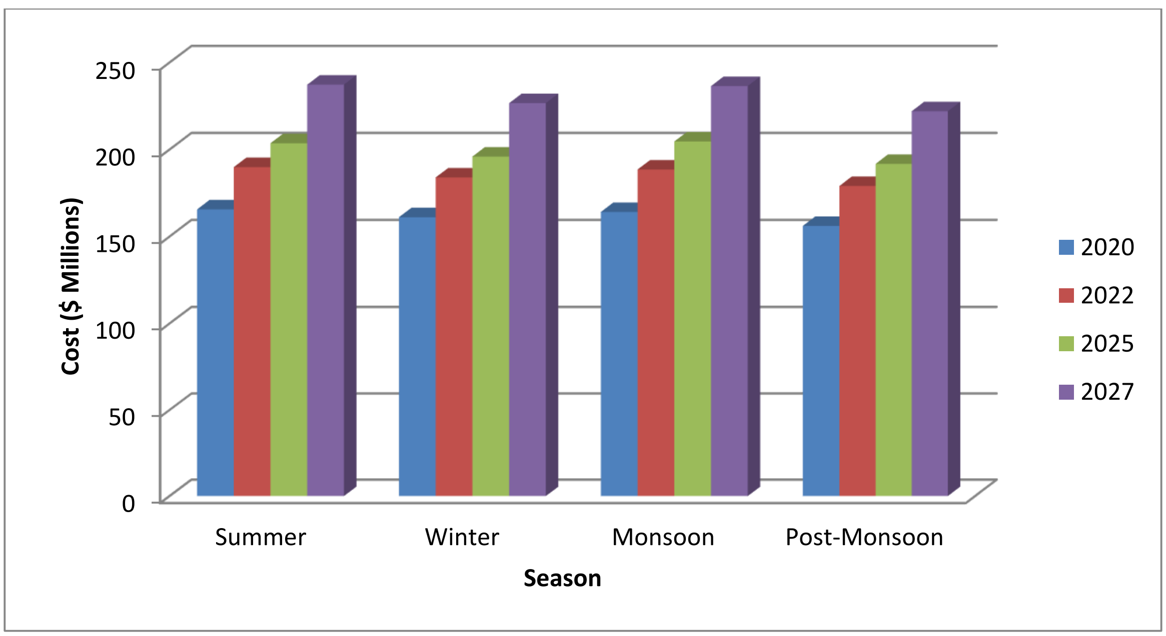

Figure 6-1: Seasonal Daily Costs of Operation with IBA Cross-Border Transmission Link For Each Year

Table 6-12 illustrates the economic benefit summary with the North-East India – Bangladesh – North India cross-border transmission link from 2020-2030.

Table 6-12: Economic Benefit Summary for the Study Period

Period	Present worth ($ millions)				
	Cost of operation of base case	Cost of operation with interconnection	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2020 - 2030	346,682.81	343,102.52	3,580.30	1,670.93	1,909.37

The results indicate a net benefit of $1,909 million for the study period. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in Appendix F – Annuitized Project Costs and Benefit-Cost Ratios.

6.3.1.2 Cross-border Transmission Link Power Transfer

Table 6-13 and Table 6-14 show the utilization of North-East India – Bangladesh cross-border transmission link (Rangia/Rowta – Barapukuria) and the Bangladesh - North India cross-border transmission link (Barapukuria - Bareily) of the IBA interconnection in years 2020, 2022, 2025 and 2027 in different seasons.

Table 6-13: Utilization of the North East India-Bangladesh Section of the Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak Transfer hour	Capacity factor (%)
2020	Summer	1928.98	21:00	31.3
	Winter	564.62	07:00	04.4
	Monsoon	2040.39	21:00	30.1
	Post-Monsoon	2294.81	20:00	28.1
2022	Summer	1930.81	19:00	28.3
	Winter	2656.89	14:00	21.3
	Monsoon	2151.67	21:00	32.4
	Post-Monsoon	2300.84	22:00	32.3
2025	Summer	3391.19	03:00	54.9
	Winter	2441.88	23:00	26.6
	Monsoon	3456.88	21:00	53.8
	Post-Monsoon	3596.95	21:00	53.9
2027	Summer	3325.79	23:00	53.0
	Winter	3037.83	13:00	28.0
	Monsoon	3450.86	24:00	50.8
	Post-Monsoon	3774.17	21:00	53.6

Table 6-14: Utilization of the Bangladesh- North India Section of the Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak transfer hour	Capacity factor (%)
2020	Summer	2918.78	07:00	27.5
	Winter	3220.90	05:00	34.5
	Monsoon	2854.24	07:00	30.6
	Post-Monsoon	2902.17	17:00	37.7
2022	Summer	2216.24	07:00	14.5
	Winter	3231.81	04:00	42.1
	Monsoon	2570.49	07:00	16.0
	Post-Monsoon	2970.31	18:00	35.9
2025	Summer	4170.06	07:00	66.3
	Winter	3645.53	04:00	55.0
	Monsoon	4136.70	09:00	67.0
	Post-Monsoon	4989.51	04:00	76.1
2027	Summer	3650.64	07:00	56.1
	Winter	2917.27	04:00	41.8
	Monsoon	3580.34	09:00	54.8
	Post-Monsoon	4268.31	05:00	67.0

IBA cross-border transmission link has been moderately utilized to transfer power from North-Eastern India to Bangladesh in all seasons. The capacity factors may be improved further by upgrading the transmission network near the terminals to transfer power close to 6 GW. The following lines are identified as critically-loaded lines in the vicinity of the interconnection terminals:

1. Bareily-to-Amritsar;
2. Bareily-to- Jalandha;
3. Rangia/Rowta-to- Balipara-PG.

In the winter season, due to low availability of hydro generation in North-Eastern India, power transfer is decreased even more. With the increasing demand in Bangladesh and Northern India, power transfer in the cross-border transmission link shows an increment, utilizing the interconnection more in the latter years.

6.3.1.3 Generation Dispatch Changes

Table 6-15 illustrates the selected generation dispatch changes for the IBA case compared to the base case.

Table 6-15: Selected Generation Dispatch (Daily Average) Changes Observed in The IBA Case

Year	**Season**	Coal (MW) North	Coal (MW) West	Gas (MW) Bangladesh	Hydro (MW) North East
2022	Post Monsoon	-585.07	-304.28	-375.15	817.35
2027	Post Monsoon	-1200.3	-1363.63	-123.40	2550.78
2027	Summer	-1002.45	-871.15	-145.68	2723.12

The results indicate that the cost advantage is mainly due to the replacement of higher cost coal-based power generation in the Northern and Western India and gas-based power generation in Bangladesh replaced by North-Eastern India hydro power generation.

For example, the following changes are observed during the post-Monsoon season in year 2027. High cost coal-based power generation of the power stations in Northern India (such as Karchna -1200 MW, Anparac -1200 MW, Suratg - 2320 MW) is considerably decreased. In contrast, generation in 900 MW Baglihar hydro power station is increased (plant factor is increased by 66.7%). Coal-based power generation of the power stations in Western India, such as Barethi (2640 MW), RKM (1440 MW), Athena (1200 MW) and SKS (1200 MW), is moderately decreased.

The gas based power generation in Bangladesh (such as FENC CCPP N - 110 MW, SYLHET 2 - 247.5 MW, FENCHU 1 - 115.5 MW and GHORASAL - 399 MW) is slightly decreased. However, the new nuclear power plant (Ishurdi - 2510 MW) has increased its generation (plant factor increased by 17.7%).

Hydro power generation in North-Eastern India is heavily increased, fully utilizing all of the new hydro power plants, such as Tato-II (700 MW), Tawang-I (600 MW), Tawang-II (800 MW), and Nyamjungchu (780 MW), which contribute to the power transfer in the cross-border transmission link.

6.3.1.4 Summary

Table 6-16 shows the economic analysis summary of the India-Bangladesh cross-border transmission link.

Table 6-16: Summary of Results for the India-Bangladesh Cross-Border Transmission Link

Period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net profit ($ millions)	Average Capacity (%) Factor
2020 - 2030	3,580.3	1,670.9	1,909.4	37.6

6.3.2 India – Bhutan (Rangia/Rowta - Yangbari) Interconnected Case (IBU)

6.3.2.1 Cost of Operation

Table 6-17 and Figure 6-2 illustrate the daily and annual costs of operation with the India-Bhutan cross-border transmission link for each season in different study years.

Table 6-17: Daily and Annual Cost of Operation with the Interconnection

Year	Daily cost of operation with the interconnection ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	166.95	161.50	165.21	157.31	59,401.3
2022	191.04	184.33	189.48	180.12	67,978.1
2025	206.64	197.49	207.48	194.91	73,594.6
2027	240.05	227.92	239.25	224.94	85,060.8

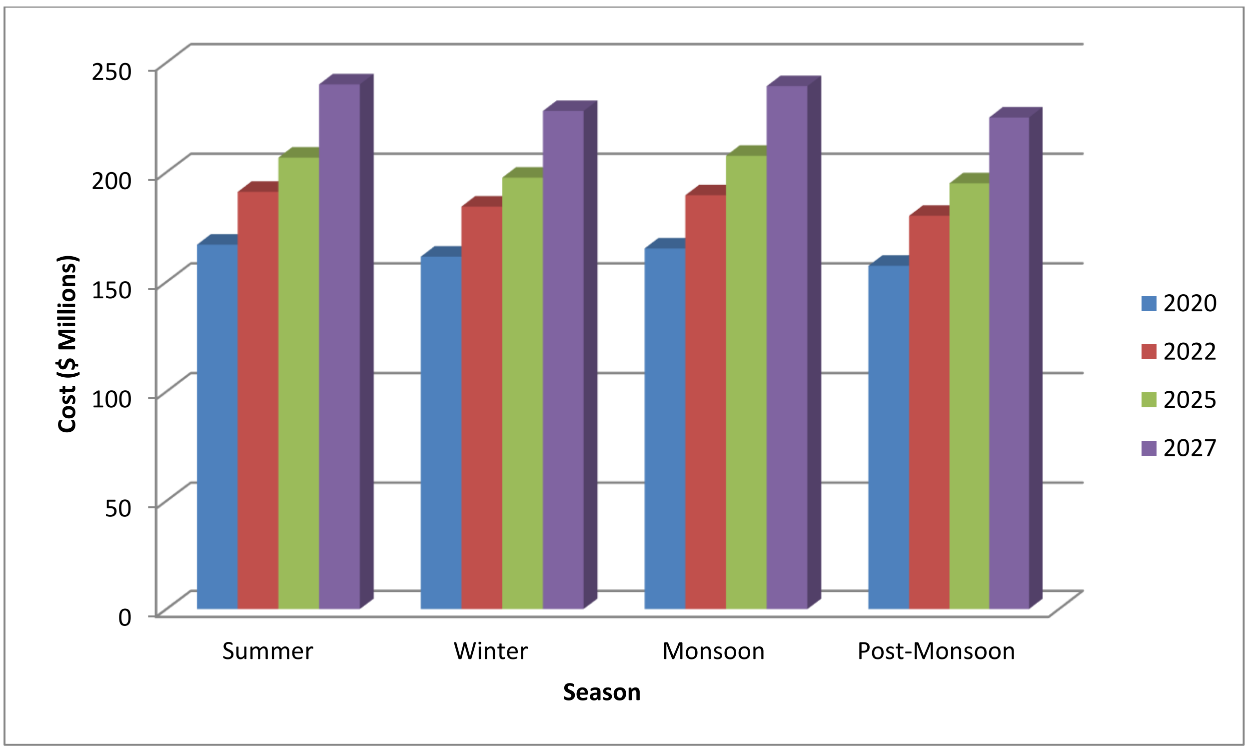

Figure 6-2: Seasonal Daily Costs of Operation with IBU Cross-Border Transmission Link for Each Year

Table 6-18 illustrates the economic benefit summary for the study period from year 2020 to 2030 with the India-Bhutan cross-border transmission link.

Table 6-18: Economic Benefit Summary for the Study Period

Period	Present worth ($ millions)				
	Cost of operation of base case	Cost of operation with cross-border transmission link	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2020 - 2030	346,682.81	345,962.84	719.97	131.70	588.27

The results indicate a net benefit of $588 million for the study period. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in Appendix F – Annuitized Project Costs and Benefit-Cost Ratios.

6.3.2.2 Cross-border Transmission Link Power Transfer

Table 6-19 illustrates the utilization of India – Bhutan cross-border transmission link in years 2020, 2022, 2025 and 2027 in different seasons.

Table 6-19: Utilization of the India-Bhutan Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak transfer hour	Capacity factor (%)
2020	Summer	245.25	21	06.4
	Winter	311.79	20	16.0
	Monsoon	329.40	21	07.5
	Post-Monsoon	253.68	4	18.0
2022	Summer	103.97	5	03.4
	Winter	362.87	21	16.2
	Monsoon	277.00	21	08.8
	Post-Monsoon	274.07	19	18.7
2025	Summer	417.00	19	29.2
	Winter	132.27	15	08.7
	Monsoon	555.99	21	31.5
	Post-Monsoon	288.49	23	17.1
2027	Summer	541.88	19	43.3
	Winter	151.71	4	05.6
	Monsoon	346.12	9	27.0
	Post-Monsoon	266.89	20	10.6

In years 2020 and 2022, power is transferred mainly from Bhutan to India, except from 19:00 to 23:00, when Bhutan is in its peak demand. However, in 2025 and 2027, power is mostly transferred from North-Eastern India to Bhutan.

In general, India - Bhutan cross-border transmission link is only slightly utilized in all the seasons, as both regions are mostly using hydro power, and the transmission system is not developed enough to effectively evacuate the power to load centers in the rest of India.

6.3.2.3 Generation Dispatch Changes

Table 6-20 shows the selected generation dispatch changes for the power system base case with India-Bhutan cross-border transmission link.

Table 6-20: Selected Generation Dispatch (Daily Average) Changes Observed in the IBU Case

Year	Season	Hydro (MW)	
		Bhutan	North East
2022	Post Monsoon	200.97	-192.79
2027	Monsoon	-290.36	281.18

It can be observed that the major changes in the case are replacements of hydro power in one region with the hydro power in the other region.

In year 2027 Monsoon season, upon connecting the IBU cross-border transmission link, power generation of Chamkarchu (770 MW), Kurichu1 (60 MW) and Chukha (336 MW) Hydro power stations in Bhutan is decreased, whereas the power generation of Patel Hydro (189 MW), Kalai-II (1200 MW), Tawang-I (600 MW), Tawang-II (800 MW), and Nyamjungchu (780 MW) hydro power stations in India is increased. This is the reason for the lower economic benefit and utilization of the cross-border transmission link.

6.3.2.4 Summary

Table 6-21 shows the economic analysis summary of the India-Bhutan cross-border transmission link.

Table 6-21: Summary of Results for the India-Bhutan Cross-Border Transmission Link

Period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net profit ($ millions)	Average Capacity (%) factor
2020 - 2030	720.0	131.7	588.3	16.7

6.3.3 India – Nepal (Gorakhpur – Marsyangdi) Interconnected Case (IN1)

6.3.3.1 Cost of Operation

Table 6-22 and Figure 6-3 illustrate the daily and annual costs of operation with the Gorakhpur – Marsyangdi (IN1) cross-border transmission link for each season in different study years.

Table 6-22: Daily and Annual Cost of Operation with the Cross-Border Transmission Link

Year	Daily cost of operation with the cross-border transmission link ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	166.33	160.90	164.49	157.24	59,218.9
2022	190.51	183.82	188.84	179.51	67,770.1
2025	205.74	196.78	206.50	193.03	73,187.7
2027	239.17	227.10	238.32	224.04	84,738.0

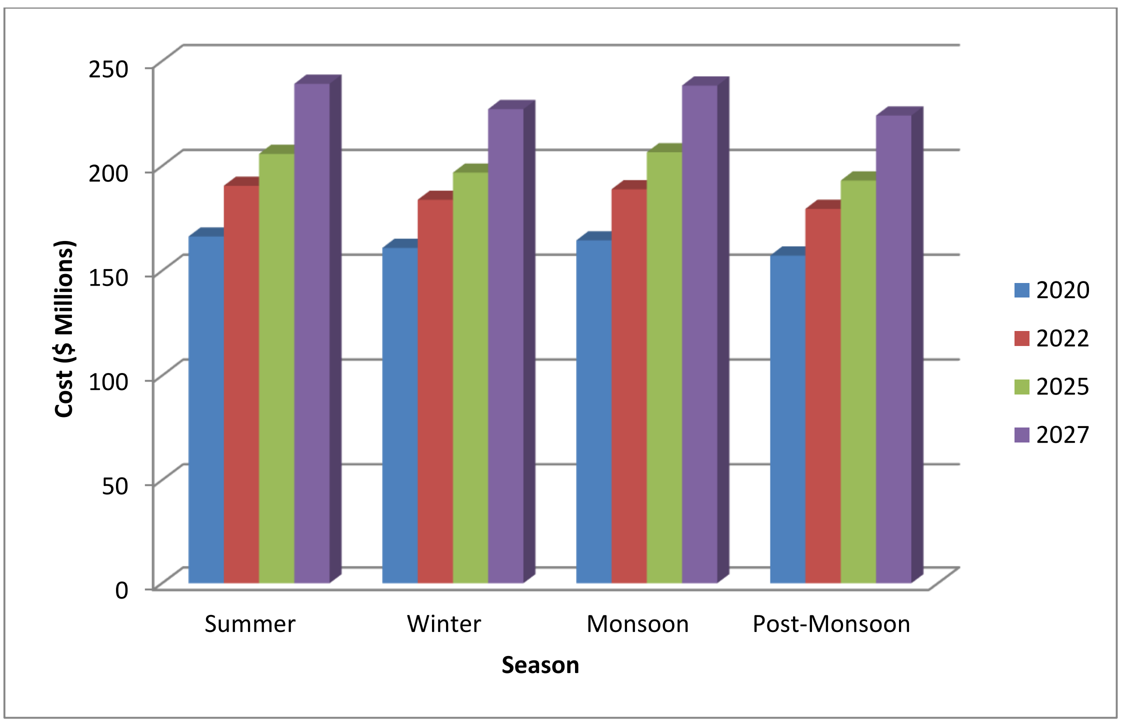

Figure 6-3: Seasonal Daily Costs of Operation with IN1 Cross-Border Transmission Link for Each Year

Table 6-23 illustrates the economic benefit summary for the study period from year 2020 to 2030 with IN1 India-Nepal cross-border transmission link.

Table 6-23: Economic Benefit Summary for the study period

Period	Present worth ($ millions)				
	Cost of operation of base case	Cost of operation with interconnection	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2020 - 2030	346,682.81	344,679.80	2,003.02	279.86	1,723.16

The results indicate a net benefit of $1,723 million for the study period. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in the Appendix F – Annuitized Project Costs and Benefit-Cost Ratios.

6.3.3.2 Cross-border Transmission Link Power Transfer

Table 6-24 illustrates how the India – Nepal power cross-border transmission link is being utilized in years 2020, 2022, 2025 and 2027 in different seasons.

Table 6-24: Utilization of the IN1 India-Nepal section of the cross-border transmission link

Year	Season	Maximum Power transfer (MW)	Peak transfer hour	Capacity factor (%)
2020	Summer	122.62	21:00	78.1
	Winter	827.25	01:00-04:00, 07:00-08:00, 11:00-17:00, 22:00-24:00	81.3
	Monsoon	855.08	02:00-04:00, 06:00-08:00, 13:00-14:00, 16:00, 18:00	84.2
	Post-Monsoon	600.00	01:00-18:00, 21:00-24:00	58.5
2022	Summer	727.48	01:00-07:00, 09:00-17:00, 24:00	71.1
	Winter	784.55	01:00-04:00, 08:00, 11:00-16:00, 24:00	75.5
	Monsoon	804.20	01:00-07:00, 09:00-17:00	78.2
	Post-Monsoon	826.21	01:00-17:00, 24:00	80.4
2025	Summer	878.40	01:00-19:00	86.7
	Winter	926.98	09:00-14:00, 17:00-18:00, 22:00-24:00	89.6
	Monsoon	891.65	03:00,	87.7

Year	Season	Maximum Power transfer (MW)	Peak transfer hour	Capacity factor (%)
			05:00-20:00	
	Post-Monsoon	886.53	01:00-24:00	88.7
2027	Summer	806.36	01:00-13:00, 17:00-19:00	79.0
	Winter	938.92	01:00-02:00, 07:00-18:00, 22:00-24:00	89.8
	Monsoon	851.19	06:00-19:00	84.1
	Post-Monsoon	885.70	02:00-07:00, 09:00-18:00	85.6

India - Nepal cross-border transmission link is well-utilized throughout the study period, and the cross-border transmission link is at its peak most of the hours of the day. Power is transferred from Nepal to India in almost all seasons in each year. However, in summer of 2020, when Nepal daily peak occurs, power is transferred from India to Nepal.

6.3.3.3 Generation Dispatch Changes

Table 6-25 illustrates the typical generation dispatch changes for the power system base case with India-Nepal cross-border transmission link.

Table 6-25: Selected Generation Dispatch (Daily Average) Changes Observed in the IN1 Case

		Coal (MW)		Hydro (MW)
Year	Season	East	North	Nepal
2025	Monsoon	-133.6	-551.81	1158.04

The results indicate that the cost advantage is mainly due to the replacement of higher cost coal-based power generation in the Northern and Eastern India by hydro power in Nepal.

In year 2027 monsoon season, hydro power generation of the power plants in Nepal, such as Bud Gandk Ka (130 MW), Low Man Mars (140 MW), Manang Marsy (282 MW), and Bud Gand Kha (260 MW), are considerably increased. Furthermore, Upper Arun (335 MW), Dudh koshi (300 MW), Lower Arun (400 MW) generator stations are fully utilized to transfer power from Nepal to India through IN1 cross-border transmission link.

6.3.3.4 Summary

Table 6-26 shows the economic analysis summary of the IN1 cross-border transmission link.

Table 6-26: Summary of Results for the IN1 India-Nepal Cross-Border Transmission Link

Period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net profit ($ millions)	Average Capacity (%) factor
2020 - 2030	2,003.0	279.9	1,723.2	81.1

6.3.4 India – Nepal (Bareilly - Upper Karnali) Interconnected Case (IN2)

Nepal power system network data before 2025 do not include high-voltage connections to Marsyangdi, and there are no large generators in the vicinity. Therefore, Bareilly - Upper Karnali (IN2) cross-border transmission link is studied for the 2025-2030 period.

6.3.4.1 Cost of Operation

Table 6-27 and Figure 6-4 illustrate the daily and annual costs of operation with the Bareilly - Upper Karnali (IN2) cross-border transmission link for each season in different study years.

Table 6-27: Daily and Annual Cost of Operation with the Cross-Border Transmission Link

Year	Daily cost of operation with the cross-border transmission link ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2025	205.44	196.43	206.22	193.74	73,166.0
2027	238.92	226.79	237.93	223.71	84,620.5

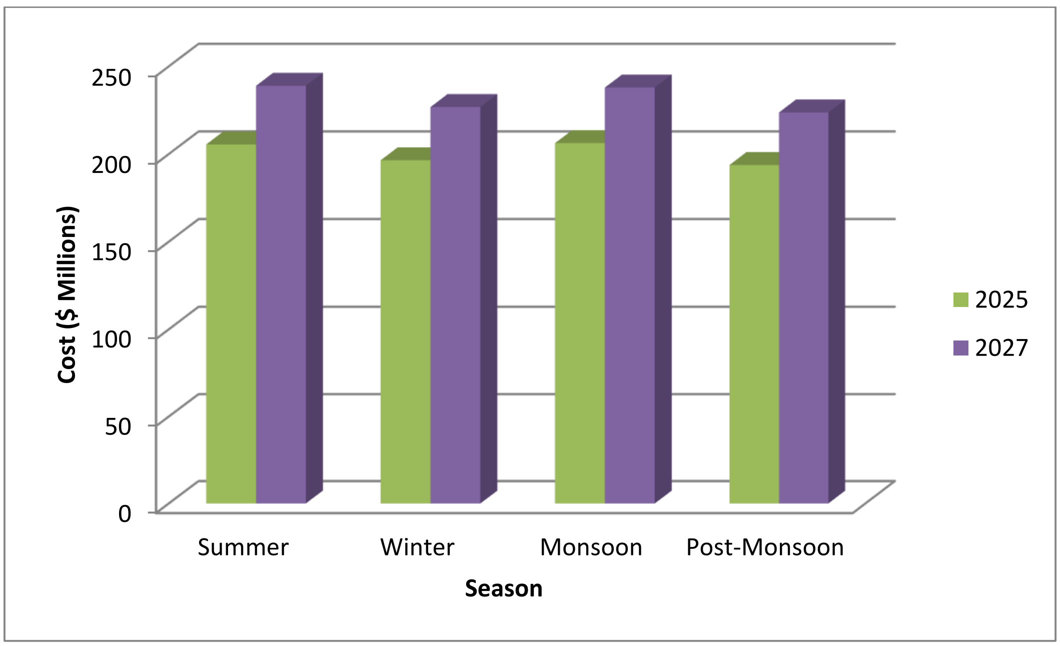

Figure 6-4: Seasonal Daily Costs of Operation with IN2 Cross-Border Transmission Link For Year 2025 And 2027

Economic benefit summary for the study period from year 2025 to 2030 with IN2 cross-border transmission link is shown in Table 6-28.

Table 6-28: Economic Benefit Summary for the Study Period

Period	Present worth ($ millions)				
	Cost of operation of base case	Cost of operation with cross-border transmission link	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2020 - 2030	163,977.79	162,654.64	1,323.16	82.25	1,240.90

The results indicate a net benefit of $1,241 million for the study period of 2025-2030. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in Appendix F – Annuitized Project Costs and Benefit-Cost Ratios.

6.3.4.2 Cross-border Transmission Link Power Transfer

The following Table 6-29 reports the utilization of the IN2 cross-border transmission link in years 2025 and 2027 in different seasons.

Table 6-29: Utilization of the IN2 India-Nepal Cross-Border Transmission Link

	Season	Power transfer peak (MW)	Maximum Peak hour	Capacity factor (%)
2025	Summer	10.00	01:00-19:00	98.2
	Winter	10.00	01:00-24:00	100.0
	Monsoon	10.00	03:00, 05:00-20:00	96.5
	Post-Monsoon	10.00	01:00-20:00, 22:00-24:00	99.9
2027	Summer	10.00	03:00-05:00, 07:00-10:00, 18:00-19:00	95.7
	Winter	9.99	01:00, 15:00	99.4
	Monsoon	10.00	06:00-20:00	97.7
	Post-Monsoon	10.00	01:00-07:00, 09:00-19:00	98.0

As the table indicates, IN2 cross-border transmission link is very well-utilized, with the capacity factors close to 100% throughout the period. In addition, power transfer direction remains unchanged from Nepal to India.

6.3.4.3 Generation Dispatch Changes

Table 6-30 illustrates the typical generation dispatch changes for the power system base case with India-Nepal cross-border transmission link.

Table 6-30: Selected Generation Dispatch (Daily Average) Changes Observed in the IN2 Case

		Coal (MW)		Hydro (MW)
Year	Season	West	North	Nepal
2027	Monsoon	-717.36	-1212.5	2333.87

The results indicate that the cost advantage is mainly due to the replacement of higher cost coal-based power generation in the Northern and Western India by hydro power in Nepal.

In year 2027 monsoon season, Tila 1 (440 MW) and Tila 2 (420 MW) new generator stations in Nepal significantly contribute to the power transfer to India in the IN2 cross-border transmission link. In addition, power generation of Upper Arun (335 MW), Dudh koshi (300 MW), Tomar storage (200 MW) and Lower Arun (400 MW) generator stations has also slightly increased.

6.3.4.4 Summary

Table 6-31 shows the economic analysis summary of the IN2 cross-border transmission link.

Table 6-31: Summary of Results for the IN2 India-Nepal Cross-Border Transmission Link

Period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net profit ($ millions)	Average Capacity (%) factor
2025 - 2030	1,322.1	82.3	1,239.9	98.2

6.3.5 India – Sri Lanka (Madurai – Anuradhapura) Interconnection - ISL

6.3.5.1 Cost of Operation

Table 6-32 and Figure 6-5 present the daily and annual costs of operation with the India-Sri Lanka cross-border transmission link for each season in different years.

Table 6-32: Daily and Annual Cost of Operation with the Cross-Border Transmission Link

Year	Daily cost of operation with the cross-border transmission link ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	166.93	161.48	165.24	157.28	59,398.4
2022	191.00	184.30	189.47	180.11	67,971.7
2025	206.63	197.48	207.48	194.90	73,593.2
2027	240.02	227.88	239.22	224.92	85,047.8

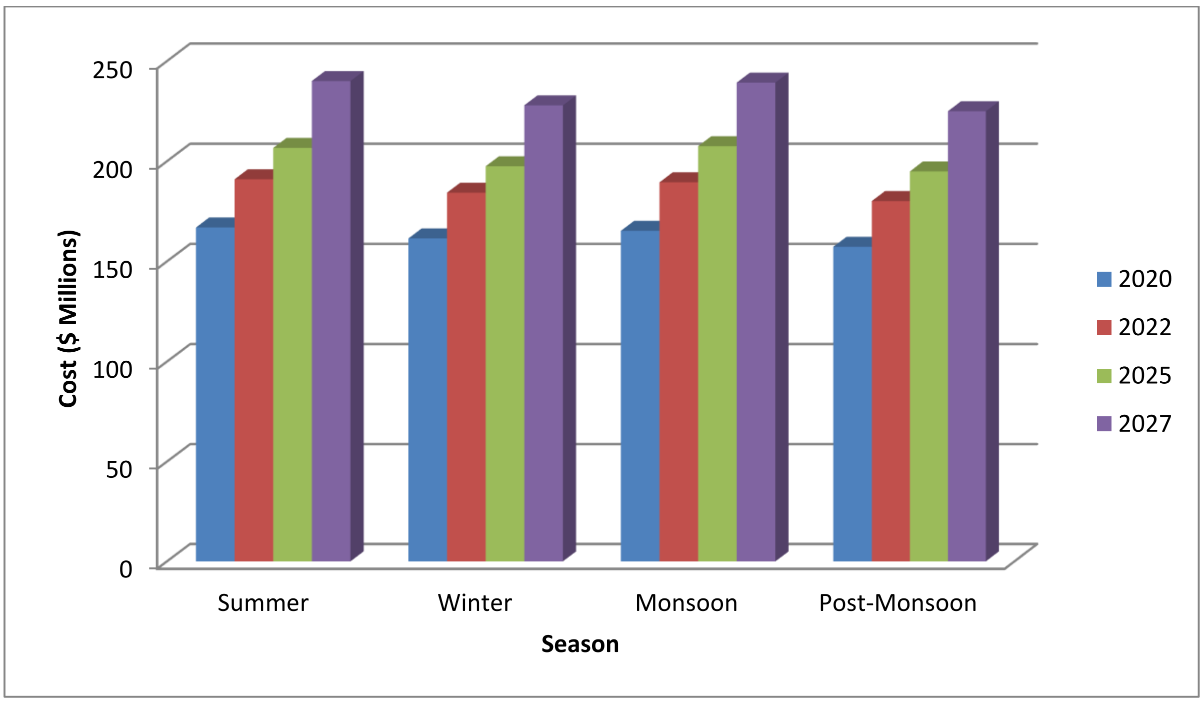

Figure 6-5: Seasonal Daily Costs of Operation with ISL Cross-Border Transmission Link for Each Year

Table 6-33 illustrates the economic benefit summary for the study period from year 2020 to 2030 with India - Sri Lanka cross-border transmission link.

Table 6-33: Economic Benefit Summary for the Study Period

Period	Present worth ($ Millions)				
	Cost of operation of base case	Cost of operation with cross-border transmission link	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2020 - 2030	346,682.81	345,932.09	750.72	255.17	495.56

The results indicate a net benefit of $495 million for the study period. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in the Appendix F – Annuitized Project Costs and Benefit-Cost Ratios.

6.3.5.2 Cross-border Transmission Link Power Transfer

The following Table 6-34 presents the utilization of the India – Sri Lanka cross-border transmission link in years 2020, 2022, 2025 and 2027 in different seasons.

Table 6-34: Utilization of the India-Sri Lanka Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak Transfer hour	Capacity factor (%)
2020	Summer	499.99	17:00, 19:00	64.6
	Winter	499.99	09:00	83.8
	Monsoon	499.99	23:00	77.4
	Post-Monsoon	499.99	18:00	75.0
2022	Summer	499.99	11:00-15:00	89.1
	Winter	499.99	08:00	79.0
	Monsoon	499.99	22:00	94.7
	Post-Monsoon	499.99	19:00	92.6
2025	Summer	499.99	6,18	52.2
	Winter	499.94	22	63.7
	Monsoon	500.00	12:00	77.3
	Post-Monsoon	499.98	23:00	62.1
2027	Summer	500.00	7	63.8
	Winter	499.97	9	86.2
	Monsoon	499.99	16, 23	72.7
	Post-Monsoon	500.00	19	67.6

India – Sri Lanka cross-border transmission link is efficiently utilized to transfer power from India to Sri Lanka and vice versa in all seasons. In general, power is transferred from Sri Lanka to India, except when the load in Sri Lanka is at its peak. In years 2020 and 2022, monsoon and post-monsoon seasons, due to the high availability of hydro power, power is transferred from Sri Lanka to India, utilizing the maximum capacity of the cross-border transmission link. However, with the increasing demand in years 2025 and 2027, Sri Lanka consumes power from India during its day peak and night peak.

6.3.5.3 Generation Dispatch Changes

Table 6-35 and Table 6-36 illustrate the average generation dispatch changes for India-Sri Lanka cross-border transmission link in years 2022 and 2027.

Table 6-35: Selected Generation Dispatch (Daily Average) Changes Observed in the ISL Case (2022)

Year	Season	India to Sri Lanka Transfer (periods-7, 8, 18, 20-24)			Sri Lanka to India Transfer (periods-1-6,9-17,19)		
		Coal (MW)		Diesel (MW)	Coal (MW)		Gas(MW)
2022	Summer	India South	Sri Lanka	Sri Lanka	India South	Sri Lanka	India South
		174.0	-91.5	-10.0	-304.6	324.7	-9.0

Table 6-36: Selected Generation Dispatch (Daily Average) Changes Observed in the ISL Case (2027)

Year	Season	India to Sri Lanka Transfer (periods-1, 2, 20, 21)			Sri Lanka to India Transfer (periods-3-19, 22-24)		
		Coal (MW)		Diesel (MW)	Coal (MW)		Diesel (MW)
2027	Summer	India South	Sri Lanka	Sri Lanka	India South	Sri Lanka	India South
		33.8	-38.4	-4	-214.9	277.2	-20.0

It can be observed that irrespective of the power transfer direction, lower-cost coal power from one country is used instead of diesel, gas and coal-based power generation in the other country.

In year 2027 summer season, diesel-based power generation of Chunnakam (45 MW), Kelan-1 (75 MW), Kelan-2 (163 MW) and Kerawalapitiya (535 MW) generator stations is slightly decreased with the addition of ISL cross-border transmission link, as the power is transferred from India to Sri Lanka during the peak hours. In addition, power generation of the new coal-based power generator stations, such as Sampoor (454 MW new), Sampoor (1100 MW upgraded) and Hambantota (275 MW new) generation stations, is significantly increased.

It should be noted that even though coal prices are assumed to be equal in both countries, coal-based power import can be cheaper rather than local generation due to locational marginal price (LMP) differences.

6.3.5.4 Summary

Table 6-37 shows the economic analysis summary of the India-Sri Lanka (ISL) cross-border transmission link.

Table 6-37: Summary of Results for the India-Sri Lanka Cross-Border Transmission Link

Period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net profit ($ millions)	Average Capacity (%) factor
2020 - 2030	750.7	255.17	494.54	75.1

6.3.6 India – Pakistan (Amritsar - Lahore) Cross-border Transmission Link - IPA

6.3.6.1 Cost of Operation

Table 6-38 and Figure 6-6 illustrate the daily and annual costs of operation with the India-Pakistan cross-border transmission link for each season in different study years.

Table 6-38: Daily and Annual Cost of Operation with the Cross-Border Transmission Link

Year	Daily cost of operation with the cross-border transmission link ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	166.69	161.38	165.21	157.07	59,344.8
2022	190.71	183.88	189.34	179.78	67,863.7
2025	206.02	197.02	206.32	193.08	73,222.9
2027	239.63	227.65	238.52	224.39	84,880.0

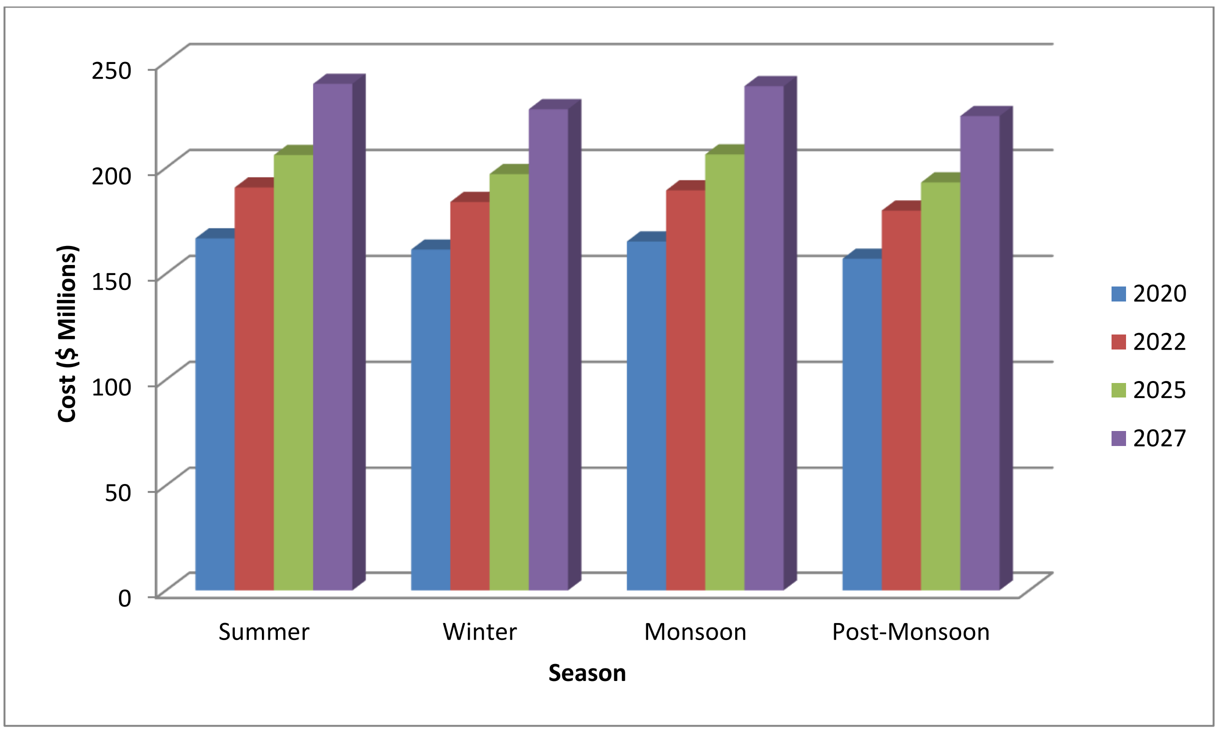

Figure 6-6: Seasonal Daily Costs of Operation with ISL Cross-Border Transmission Link for Each Year

Table 6-39 illustrates the economic benefit summary for the study period from year 2020 to 2030 with India-Pakistan cross-border transmission link.

Table 6-39: Economic Benefit Summary for the Study Period

Period	Present worth ($ Millions)				
	Cost of operation of base case	Cost of operation with interconnection	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2020 - 2030	346,682.81	345,190.42	1,492.39	169.97	1,322.42

The results indicate a net benefit of $1,322 million for the study period. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in the Appendix F – Annuitized Project Costs and Benefit-Cost Ratios.

6.3.6.2 Cross-Border Transmission Link Power Transfer

Table 6-40 illustrates how the India – Pakistan cross-border transmission link is being utilized in years 2020, 2022, 2025 and 2027 in different seasons.

Table 6-40: Utilization of the India-Pakistan Cross-Border Transmission Link

Year	Season	Power transfer peak (MW)	Peak transfer hour	Capacity factor (%)
2020	Summer	1000.00	09:00-15:00	76.1
	Winter	1000.00	10:00–15:00	78.5
	Monsoon	999.98	24:00	82.4
	Post-Monsoon	1000.00	09:00-16:00	86.9
2022	Summer	1000.00	08:00-15:00	76.3
	Winter	1000.00	06:00-15:00	80.8
	Monsoon	1000.00	12:00-15:00	90.9
	Post-Monsoon	1000.00	06:00-15:00	90.2
2025	Summer	1000.00	01:00-07:00, 16:00–24:00	89.8
	Winter	999.99	02:00-05:00, 16:00-24:00	80.1
	Monsoon	1400.00	01:00 -24:00	100.0
	Post-Monsoon	2217.05	00:00-14:00, 16:00-24:00	100.0
2027	Summer	1000.00	12:00-16:00, 19:00-22:00	86.3
	Winter	999.99	12:00-15:00	68.9
	Monsoon	1000.00	01:00-09:00, 16:00-24:00	99.5
	Post-Monsoon	1000.00	01:00-05:00, 16:00-24:00	79.9

India – Pakistan cross-border transmission link is efficiently utilized throughout the study period. Power transfer direction is generally from India to Pakistan (except for Northern

India peak load periods). However, after 2025, large hydro developments in Pakistan indicated in the planning reports (e.g. BASHA-1, BASHA-2, BUNJI, etc.) reverse the power flow direction. A detailed list of new large generation developments in Pakistan is given in Table 10-15 in the Appendix A - Power System Overview.

6.3.6.3 Generation Dispatch Changes

Table 6-41 illustrates the average generation dispatch changes for India-Pakistan cross-border transmission link in years 2022.

Table 6-41: Selected Generation Dispatch (Daily Average) Changes Observed in the IPA Case

Year	Season	Pakistan to India Transfer (periods-18, 20, 21, 22)			India to Pakistan Transfer (periods- 1-17, 19, 23, 24)		
		Coal (MW)			Coal (MW)		Gas (MW)
2022	Winter	India North	India West	Pakistan	India North	India West	Pakistan
		-30.43	-114.46	289.68	559.74	141.08	-280.19

The results indicate that the cost advantage in the period before 2025 is mainly due to the replacement of higher cost gas-based power generation in Pakistan by coal-based power in Northern India. However, after 2025, a large number of hydro power plants (e.g. BASHA-1, BASHA-2, BUNJI, etc.) is to be commissioned in Pakistan. A detailed list of new large generation developments in Pakistan is given in Table 10-15 in the Appendix A - Power System Overview. Therefore, if these power plants are realized, power transfer direction is reversed and flows from Pakistan to India.

In year 2027 winter season, gas-based power generation at C-3/C-4 (325 MW), C-1/C-2 (325 MW) and Bhikki (725 MW) generator stations in Pakistan is slightly decreased as the power is transferred from India to Pakistan through the cross-border transmission link. However, nuclear power generation of Paec-1 (1000 MW existing) has increased with the inclusion of the IPA cross-border transmission link.

6.3.6.4 Summary

Table 6-42 shows the economic analysis summary of the India-Pakistan (IPA) cross-border transmission link.

Table 6-42: Summary of Results for the India-Pakistan Cross-Border Transmission Link

Period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net profit ($ millions)	Average Capacity (%) factor
2020 - 2030	1,491.37	169.97	1,321.40	85.4

6.3.7 Afghanistan - Pakistan (Arghandi - Peshawar) Interconnected Case - AFPA

6.3.7.1 Cost of Operation

Table 6-43 and Figure 6-7 illustrate the daily and annual costs of operation with the Afghanistan-Pakistan cross-border transmission link for each season in different study years.

Table 6-43: Daily and Annual Cost of Operation with The Cross-Border Transmission Link

Year	Daily cost of operation with the cross-border transmission link ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	167.09	161.62	165.49	157.45	59,462.7
2022	191.17	184.45	189.69	180.24	68,031.4
2025	206.64	197.48	209.25	197.38	73,980.4
2027	240.02	227.84	239.25	224.91	85,047.0

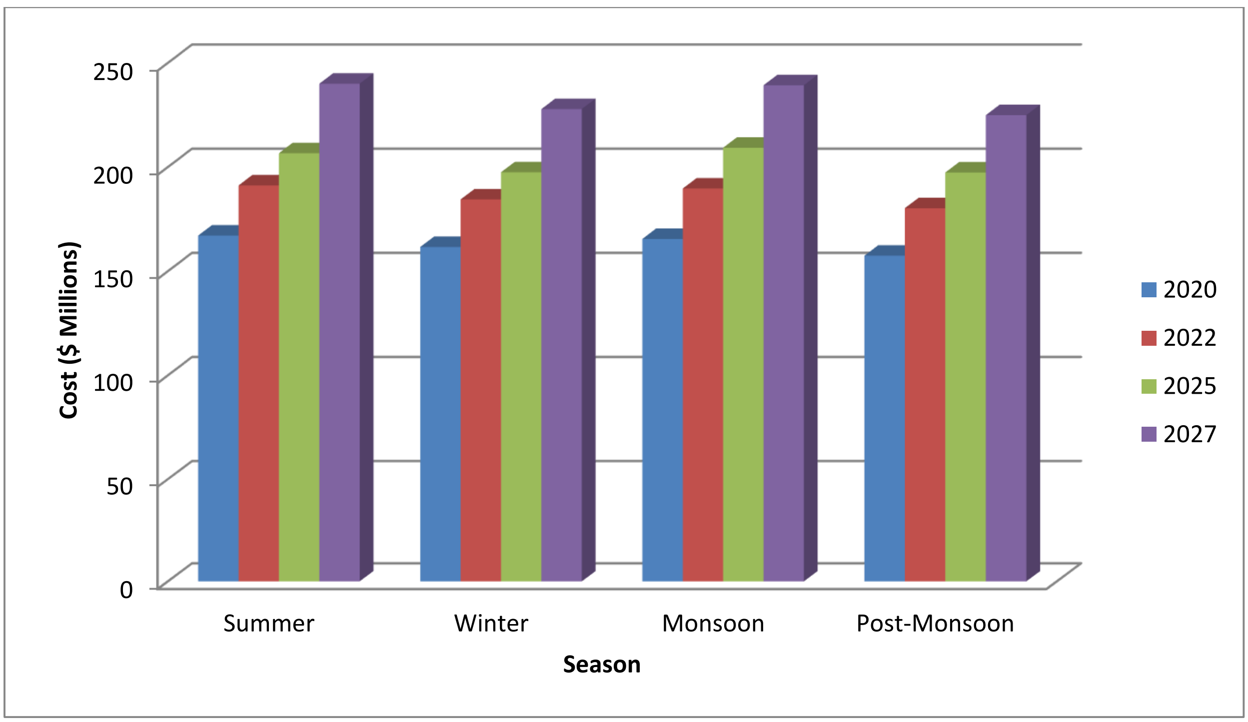

Figure 6-7: Seasonal Daily Costs of Operation with AFPA Cross-Border Transmission Link for Each Year

Table 6-44 presents the economic benefit summary for the study period from year 2020-2030 with Afghanistan-Pakistan cross-border transmission link.

Table 6-44: Economic benefit summary for the study period

Period	Present worth ($ millions)				
	Cost of operation of base case	Cost of operation with cross-border transmission link	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2020 - 2030	346,682.81	346,420.68	262.13	246.94	15.20

The results indicate a net benefit of $15 million for the study period. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in the Appendix F – Annuitized Project Costs and Benefit-Cost Ratios.

6.3.7.2 Cross-border Power Transfer

The following Table 6-45 illustrates how the Afghanistan – Pakistan cross-border transmission link is being utilized in years 2020, 2022, 2025 and 2027 in different seasons.

Table 6-45: Utilization of the Afghanistan-Pakistan Section of the Cross-Border Transmission Link

Year	Season	Power transfer peak (MW)	Maximum Peak hour	Capacity factor
2020	Summer	796.31	14:00	62.1
	Winter	807.34	13:00	65.1
	Monsoon	674.73	15:00	49.0
	Post-Monsoon	742.62	15:00	55.4
2022	Summer	760.44	12:00	61.9
	Winter	768.95	12:00	63.4
	Monsoon	691.44	12:00	49.6
	Post-Monsoon	693.57	12:00	54.6
2025	Summer	645.92	18:00	47.6
	Winter	649.38	18:00	48.0
	Monsoon	627.12	17:00	47.3
	Post-Monsoon	642.70	18:00	47.6
2027	Summer	457.78	19:00	24.9
	Winter	446.708	20:00	19.9
	Monsoon	1000.00	09:00	74.5
	Post-Monsoon	987.17	05:00	57.6

Afghanistan - Pakistan cross-border transmission link is heavily utilized to transfer power from Afghanistan to Pakistan and vice versa in all the seasons.

Before 2025, power is transferred from Afghanistan to Pakistan in all seasons, utilizing almost half the capacity of the cross-border transmission link. After 2025, a large number of coal- and hydro-based power plants (e.g. BASHA-1, BASHA-2, BUNJI, etc.) is to be commissioned in Pakistan. Therefore, if these power plants are realized, power transfer direction is reversed and flows from Pakistan to Afghanistan.

6.3.7.3 Generation Dispatch Changes

Table 6-46 illustrates the average generation dispatch changes for Afghanistan-Pakistan cross-border transmission link in years 2022 and 2027.

Table 6-46: Selected Generation Dispatch (Daily Average) Changes Observed in the AFPA Case

Year	Season	Coal (MW)		Hydro (MW)		Import (MW)	Gas (MW)
		Pakistan	Afghanistan	Afghanistan	Pakistan	Turk	Pakistan
2022	Monsoon	-138.8	-	-	-	282.4	-85.2
2027	Monsoon	196.81	-195.36	-525.71	530.02	-	-

Before 2025, the reduction in the cost of operation is mainly attributed to the replacement of coal and gas-based power in Pakistan, such as Hubco (225 MW) and SAIF-P/H (200 MW) and Nzahda4 (1050 MW), by power import from Turkmenistan through Afghanistan network. However, due to the planned generation improvements in Pakistan after 2025, excess coal and hydro-based power generation in Pakistan replaces the coal and hydro-based power generation in Afghanistan, such as Dara-I-SUF T - 800 MW coal based power plant (plant factor reduced by 17.96%), Ishpushta - 400 MW coal based power plant (plant factor reduced by 18.34%), Kunar A - 789 MW hydro power plant (plant factor reduced by 35.40%), and Kunar B - 300 MW hydro power plant (plant factor reduced by 36.61%). It should be noted that even though the coal and hydro-based power prices are assumed to be equal in both countries, power import can be cheaper rather than using local resources due to locational marginal price (LMP) differences.

6.3.7.4 Summary

Table 6-47 shows the economic analysis summary of the Afghanistan-Pakistan (AFPA) cross-border transmission link.

Table 6-47: Summary of Results for the Afghanistan-Pakistan Cross-Border Transmission Link

Period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net profit ($ millions)	Average Capacity Factor (%)
2020 - 2030	262.13	246.93	15.19	51.8

6.3.8 PATJ Pakistan- Tajikistan Transmission Link

6.3.8.1 Cost of Operation

Table 6-48 and Figure 6-8 illustrate the daily and annual costs of operation with the Pakistan-Tajikistan cross-border transmission link for each season in different study years.

Table 6-48: Daily and Annual Cost of Operation with the Transmission Link

Year	Daily cost of operation with the transmission link ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	166.95	161.50	165.29	157.31	59,409.3
2022	191.04	184.33	189.50	180.13	67,981.4
2025	206.64	197.50	207.49	194.91	73,596.8
2027	240.05	227.92	239.25	224.94	85,059.8

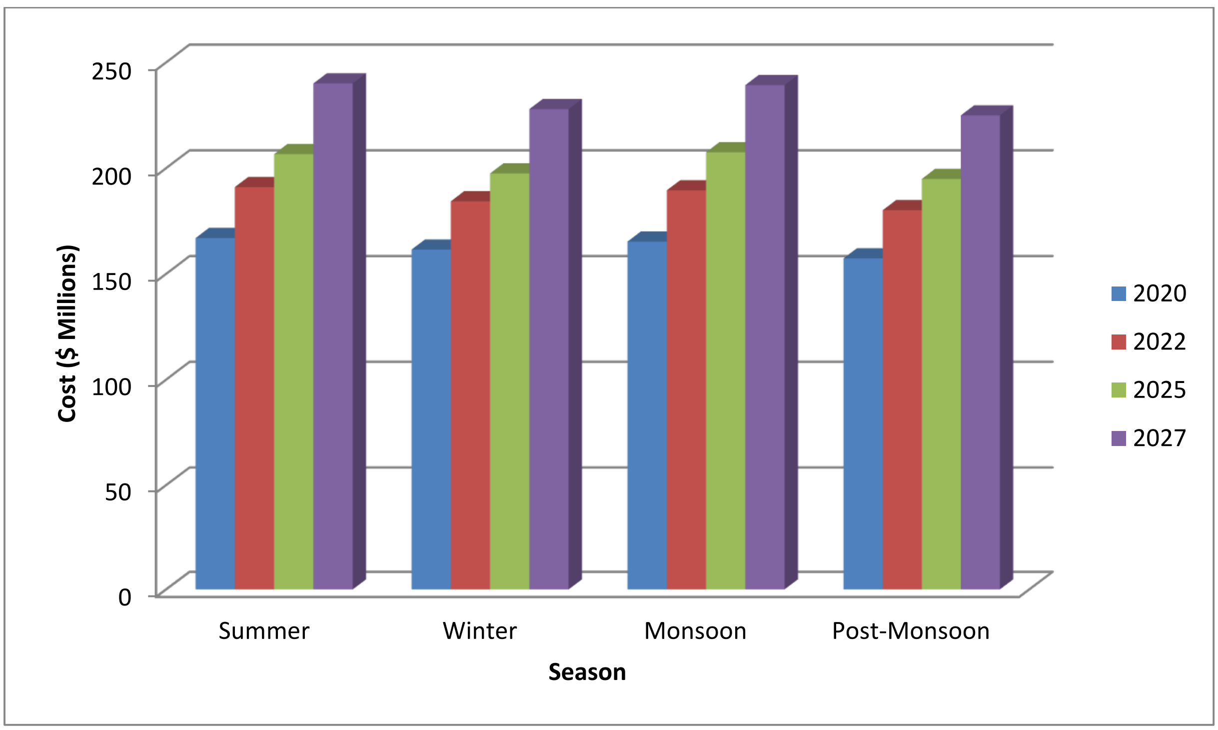

Figure 6-8: Seasonal Daily Costs of Operation with PATJ Transmission Link for Each Year

Table 6-49 illustrates the economic benefit summary for the study period from year 2020 to 2030 with Pakistan – Tajikistan cross-border transmission link.

Table 6-49: Economic Benefit Summary for the Study Period

Period	Present worth ($ millions)				
	Cost of operation of base case	Cost of operation with transmission Link	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2020 - 2030	346,682.81	345,978.82	704.00	419.79	284.21

The results indicate a net benefit of $284 million for the study period. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in the Appendix F – Annuitized Project Costs and Benefit-Cost Ratios.

6.3.8.2 Transmission Link Power Transfer

Table 6-50 illustrates how the Pakistan and Tajikistan transmission Link is being utilized in years 2020, 2022, 2025 and 2027 in different seasons.

Table 6-50: Utilization of the Pakistan-Tajikistan section of the transmission link

Year	Season	Power transfer peak (MW)	Maximum Peak hour	Capacity factor (%)
2020	Summer	473.94	15:00	16.2
	Winter	471.63	-	20.0
	Monsoon	0.00	-	0.0
	Post-Monsoon	315.86	15:00	05.8
2022	Summer	470.08	15:00	21.0
	Winter	474.50	10:00	25.8
	Monsoon	1.77	15:00	0.0
	Post-Monsoon	399.44	15:00	18.2
2025	Summer	0.00	-	0.0
	Winter	0.00	-	0.0
	Monsoon	0.00	-	0.0
	Post-Monsoon	0.00	-	0.0
2027	Summer	64.03	15:00	1.5
	Winter	470.15	14:00	15.5
	Monsoon	0.00	-	0.0
	Post-Monsoon	6.02	15:00	0.0

In general, Pakistan - Tajikistan transmission Link is slightly utilized to transfer power from Tajikistan to Pakistan before 2025. However, after 2025, the cross-border transmission link is rarely utilized due to large hydro power developments in Pakistan.

6.3.8.3 Generation Dispatch Changes

Table 6-51 illustrates the average generation dispatch changes for Pakistan-Tajikistan transmission link in years 2022 and 2027.

Table 6-51: Selected Generation Dispatch (Daily Average) Changes Observed in the PATJ Case

Year	Season	Taj Import	Gas (MW)	Coal (MW)
			Pakistan	Pakistan
2022	Post-monsoon	182.3	-182.2	-
2027	Post-monsoon	0.5	-	-

Before 2025, Tajikistan power import is used to replace the high-cost gas-based power generation in Pakistan. However, after 2025, a large number of coal and hydro-based power plants (e.g. BASHA-1, BASHA-2, BUNJI, etc.) are to be commissioned in Pakistan. These cheaper units, if realized, will greatly reduce the utilization of Tajikistan transmission link.

6.3.8.4 Summary

Table 6-52 shows the economic analysis summary of the Pakistan - Tajikistan (PATJ) cross-border transmission link.

Table 6-52: Summary of Results for the Pakistan-Tajikistan Transmission Link

Period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net profit ($ millions)	Average Capacity (%) factor
2020 - 2030	704.00	419.79	284.21	7.8

6.4 Results Summary: Individual Potential Cross-Border Transmission Links

Table 6-53 and Figure 6-9 present a summary of results for all studied individual cross-border transmission link.

Table 6-53: Summary of Results - All Individual Cross-Border Transmission Links

Study case	Study period	Cost advantage ($ Millions)	Annuitized capital cost for the study period ($ Millions)	Net benefit ($ millions)	Average capacity factor (%)
IBA	2020-2030	3,580.30	1,670.93	1,909.37	37.6
IBU	2020-2030	719.97	131.70	588.27	16.7
IN1	2020-2030	2,003.02	279.86	1,723.16	81.1
IN2	**2025-2030**	1,323.16	82.25	1,240.90	98.2
ISL	2020-2030	750.72	255.17	495.56	75.1
IPA	2020-2030	1,492.39	169.97	1,322.42	85.4
AFPA	2020-2030	262.13	246.94	15.20	51.8
PATJ	2020-2030	704.00	419.79	284.21	7.8

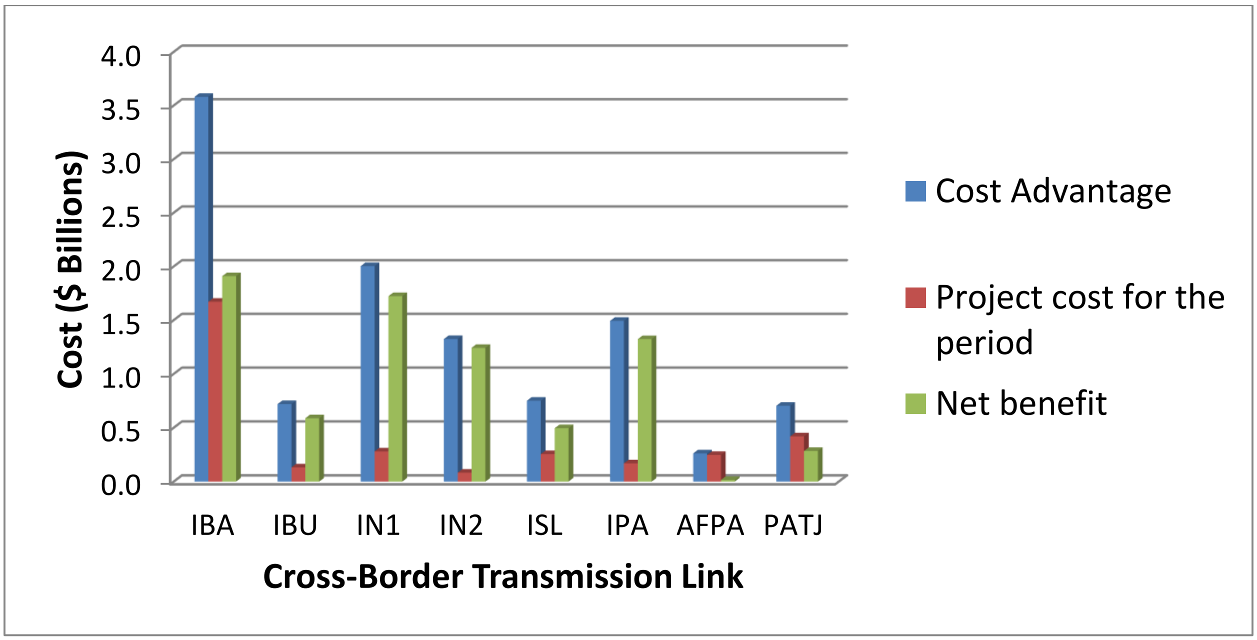

Figure 6-9: Cross-border Transmission Links Power Transfer Cost Summery

7 Study Results: Sensitivity Scenarios

This section presents the results of sensitivity scenarios that are designed to take into account the probable variations in the regional power system development. These scenarios include:

- Simultaneous operation of individual cross-border transmission links:
  - Study of the simultaneous development of both cross-border transmission links of India-Nepal (IN1 and IN2).
  - Study of the simultaneous development of the cross-border transmission links between Bhutan-India (IBU) and North-East India – Bangladesh – North India (IBA).
- Variation of expected load growth or expected generation development:
  - Bangladesh low load growth scenario (6% load growth)
- Improvement of utilization - IBA cross-border transmission link.
- IBA - Bangladesh to North-India connection change of terminal from Barapukurita - Gurdaspur to Barapukurita – Bareilly.
- India-Sri Lanka cross-border transmission link with high LNG Penetration in Sri Lanka:
  - The Sri Lankan power system model is modified as per the report "Generation Expansion Plan-2014" by CEB.
- Simultaneous operation of North -India – Bangladesh–North East India (IBA), North East India - Bhutan (IBU) and India-Nepal (IN1 and IN2) cross-border transmission links.
- Simultaneous operation of all the cross-border transmission links.

In addition to the sensitivity studies reported in this section, a cursory study was conducted for year 2027 by including a new India – Nepal cross-border transmission link (IN3) and an additional circuit to the India – Bhutan (IBU) cross-border transmission link. The results of this study are given in Appendix I - Inclusion of new India – Bhutan and India – Nepal Cross-Border Transmission Lines.

7.1 IN12 India – Nepal

This scenario analyses the economic impact on the South Asia region when both proposed cross-border transmission links for Nepal (IN1 and IN2) are in operation.

7.1.1 Cost of Operation

Table 7-1 presents the daily and annual costs for the scenario with simultaneous operation of IN1 and IN2 cross-border transmission links for each season in different study years.

Table 7-1: Daily and Annual Cost of Operation with the Cross-Border Transmission Link

Year	Daily cost of operation with the cross-border transmission link ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2025	204.71	195.78	205.53	193.03	72,913.7
2027	238.15	225.96	237.24	223.07	84,353.7

Table 7-2 illustrates the economic benefit summary for the study time period of 2025-2030 for the IN1 and IN2 cross-border transmission links.

Table 7-2: Economic Benefit Summary for the Study Period

Period	Present worth ($ Millions)				
	Cost of operation of base case	Cost of operation with cross-border transmission link	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2025 - 2030	163,977.79	162,124.30	1,853.49	198.77	1,654.7

The results indicate a net benefit of $1,654 million for the study period. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in the Appendix F – Annuitized Project Costs and Benefit-Cost.

7.1.2 Cross-border Transmission Link Power Transfer

Table 7-3 and
Table 7-4 present the utilization of IN1 and IN2 cross-border transmission links in years 2025 and 2027 in different seasons.

Table 7-3: Utilization of the IN1 India-Nepal Section of the Cross-Border Transmission Link

Year	Season	Maximum Power Transfer (MW)	Peak transfer hour (MW)	Capacity Factor (%)
2025	Summer	600.0	01:00-20:00 23:00-24:00	100.0
	Winter	600.0	09:00-18:00 20:00-24:00	100.0
	Monsoon	600.0	01:00-19:00 22:00-24:00	100.0
	Post-Monsoon	600.0	01:00-24:00	100.0
2027	Summer	600.0	01:00-15:00 17:00-20:00 23:00-24:00	100.0

	Winter	600.0	01:00-04:00 07:00-18:00 20:00-24:00	100.0
	Monsoon	600.0	01:00-21:00 23:00-24:00	100.0
	Post-Monsoon	600.0	01:00-18:00 20:00-24:00	100.0

Table 7-4: Utilization of the IN2 India-Nepal Cross-Border Transmission Link

Year	Season	Maximum Power Transfer (MW)	Power transfer hour (MW)	Capacity Factor (%)
2025	Summer	1000.0	01:00-20:00 23:00-24:00	99.7
	Winter	1000.0	01:00 12:00-18:00 21:00-24:00	100.0
	Monsoon	1000.0	01:00-20:00 01:00-20:00	98.3
	Post-Monsoon	1000.0	01:00-24:00	100.0
2027	Summer	1000.0	01:00-19:00	97.8
	Winter	1000.0	01:00-24:00	100.0
	Monsoon	1000.0	01:00-20:00 24:00	99.7
	Post-Monsoon	1000.0	01:00-07:00 09:00-19:00 22:00-24:00	98.2

Throughout 2025 and 2027, both IN1 and IN2 are fully (maximum capacity) utilized to transfer power from Nepal to India. This is an indication that the cross-border transmission link capacity can be potentially increased.

7.1.3 Generation Dispatch Changes

Table 7-5 illustrates the generation dispatch changes for IN12 sensitivity scenario.

Table 7-5: Typical Generation Dispatch Changes Observed for the Scenario with IN1 and IN2 Cross-Border Transmission Links

Year	Season	Hydro (MW)	Coal (MW)
		Nepal	India North
2027	Summer	2119.7	-1421.7

Similar to the cases with individual India – Nepal cross-border transmission links, the cost advantage of IN12 is mainly due to the replacement of higher cost coal-based power generation in the Northern India with hydro power in Nepal.

7.1.4 Summary

Table 7-6 illustrates the summary of the cost advantage, present worth of project cost and the net profit for the IN12 India-Nepal cross-border transmission link.

Table 7-6: Summary of the IN12 India-Nepal Cross-Border Transmission Link Economic Performance

Period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net profit ($ millions)	Average Capacity (%) factor
2025 - 2030	1853.49	198.77	1,654.72	100.0/99.2

7.2 IBABU India – Bhutan – Bangladesh

This section outlines the economic impact when the India-Bhutan cross-border transmission link (IBU) and North-East India – Bangladesh – North India cross-border transmission link (IBA) are in simultaneous operation for the study period year 2020 to 2030.

7.2.1 Cost of Operation

Table 7-7 presents the daily and annual costs for the scenario with simultaneous operation of the IBU and IBA cross-border transmission links for each season in different study years.

Table 7-7: Daily and Annual Cost of Operation with the Cross-Border Transmission Link

Year	Daily cost of operation with the cross-border transmission link ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	165.39	161.06	163.54	155.68	58,916.4
2022	189.70	183.94	187.90	178.54	67,531.8
2025	203.37	195.96	204.16	191.51	72,543.8
2027	237.09	226.67	235.98	221.57	84,070.0

Table 7-8 illustrates the economic benefit summary for the study time period of 2020-2030 for the IBA and IBU cross-border transmission links.

Table 7-8: Economic Benefit Summary for the Study Period

Period	Present worth ($ millions)				Net benefit ($ millions)
	Cost of operation of base case	Cost of operation with cross-border transmission link	Cost Advantage	Annuitized capital cost for the study period	
2020 - 2030	346,682.81	342,579.65	4,103.17	1,802.63	2,300.54

The results indicate a net benefit of $2,300 million for the study period. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in Appendix F – Annuitized Project Costs and Benefit-Cost.

7.2.2 Cross-border Transmission Link Power Transfer

Table 7-9 and Table 7-10 illustrate the utilization of the North-East India – Bangladesh section and Bangladesh – North India section of the IBA cross-border transmission link.

Table 7-9: Utilization of the Bangladesh – North India Section of the IBA Cross-Border Transmission Link

Year	Season	Power transfer peak (MW)	Peak transfer hour	Capacity factor (%)
2020	Summer	2933.1	07:00	32.2
	Winter	3275.0	04:00	42.2
	Monsoon	2964.6	08:00	39.5
	Post-Monsoon	3071.0	04:00	43.8
2022	Summer	2710.5	08:00	21.3
	Winter	3231.8	04:00	42.0
	Monsoon	2795.4	08:00	30.1
	Post-Monsoon	3117.8	17:00	45.2
2025	Summer	4528.6	07:00	73.6
	Winter	3612.8	04:00	53.9
	Monsoon	4512.8	09:00	75.7
	Post-Monsoon	4949.6	04:00	78.7
2027	Summer	3782.9	07:00	61.1
	Winter	2917.7	04:00	40.9
	Monsoon	3942.1	09:00	62.5
	Post-Monsoon	4719.0	04:00	75.3

Table 7-10: Utilization of the North-East India - Bangladesh Section of the Cross-Border Transmission Link

Year	Season	Power transfer peak (MW)	Maximum Peak hour	Capacity factor
2020	Summer	2710.35	21:00	37.41
	Winter	2424.09	13:00	22.48
	Monsoon	2988.94	21:00	44.53
	Post-Monsoon	3053.51	23:00	40.12
2022	Summer	2834.51	19:00	39.54
	Winter	2659.12	14:00	21.01
	Monsoon	2985.08	21:00	47.92
	Post-Monsoon	3044.47	01:00	44.33
2025	Summer	4017.84	21:00	61.91
	Winter	2437.46	23:00	27.29
	Monsoon	4472.95	23:00	67.44
	Post-Monsoon	4562.38	22:00	67.16
2027	Summer	4253.50	20:00	60.11
	Winter	3029.04	13:00	30.02
	Monsoon	4516.43	24:00	63.14
	Post-Monsoon	4545.49	23:00	65.78

Similarly to IBA case, North-East India – Bangladesh – North India cross-border transmission link has been moderately utilized in all the seasons. However, the capacity factors of both sections of the cross-border transmission links have increased in this scenario. In general, winter capacity factors are significantly less due to low hydro availability.

Table 7-11 shows the utilization of North-East India – Bhutan (IBU) cross-border transmission link.

Table 7-11: Utilization of the IBU Cross-Border Transmission Links

Year	Season	Power transfer peak (MW)	Maximum Peak hour	Capacit y factor (%)
2020	Summer	825.0	20:00	54.1
	Winter	990.2	21:00	33.8
	Monsoon	1100.0	20:00-24:00	89.4
	Post-Monsoon	902.2	20:00-23:00	80.4
2022	Summer	815.3	19:00	60.3
	Winter	674.8	21:00	33.8
	Monsoon	571.3	01:00-03:00, 11:00, 14:00-24:00	97.1
	Post-Monsoon	1033.4	1:00,6:00,16:00,23:00,24:00	88.9
2025	Summer	1100.0	20:00	46.8

Year	Season	Power transfer peak (MW)	Maximum Peak hour	Capacity factor (%)
	Winter	815.2	19:00	27.6
	Monsoon	877.7	20:00	77.0
	Post-Monsoon	1064.9	21:00	80.3
2027	Summer	825.0	20:00	43.4
	Winter	990.2	22:00	38.5
	Monsoon	1100.0	24:00	72.6
	Post-Monsoon	902.2	21:00-23:00	82.2

In general, India - Bhutan (IBU) cross-border transmission link is utilized much better when connected in tandem with the IBA cross-border transmission link compared to the individual connection. It can be seen that the winter capacity factors are much less due to low hydro availability in Bhutan.

7.2.3 Generation Dispatch Changes

Table 7-12 illustrates the generation dispatch (daily average) changes for India-Bhutan-Bangladesh cross-border transmission links in years 2022 and 2027.

Table 7-12: Generation Dispatch Changes for the IBABU India-Bhutan-Bangladesh Cross-Border Transmission Links

		Hydro (MW)		Coal (MW)		Gas (MW)
Year	Season	India North East	Bhutan	India North	India West	Bangladesh
2022	Summer	1108.3	329.2	-1736.7	-	-530.5
2027	Summer	3219.3	282.3	-1730.8	-723.5	-180.6

The results indicate that the cost advantage is mainly due to the replacement of higher cost coal-based power generation in the Northern/Western India and gas-based power generation in Bangladesh with hydro power in North-Eastern India and Bhutan.

7.2.4 Summary

Table 7-13 illustrates the summary of the cost advantage, present worth of project cost and the net profit for the India-Bhutan-Bangladesh cross-border transmission link.

Table 7-13: Summary of the IBABU India-Bhutan-Bangladesh Cross-Border Transmission Link Economic Performance

Period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net profit ($ millions)	Average Capacity (%) factor
2020 - 2030	4,103.17	1,802.63	2,300.54	46.2/51.1/62.8

7.3 Bangladesh Low Load Growth Scenario

This section shows the results of the base, IBA and IBABU cases when considering a low load growth for Bangladesh. The original base cases use the load forecast based on government policy described in [2]. This new set of scenarios uses the 6% GDP growth as noted in the same document.

7.3.1 Cost of Operation

7.3.1.1 Base Case

Table 7-17 illustrates the daily and annual costs of base case for each season in different years.

Table 7-14: Daily and Annual Cost of Operation for the Base Case (BAN 6% growth)

Year	Daily cost of operation for the regional base case ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	154.78	151.17	153.35	145.44	55,182.9
2022	176.93	172.48	176.49	167.08	63,235.0
2025	191.90	182.51	190.78	178.47	67,858.6
2027	221.36	212.74	220.39	206.51	78,567.2

7.3.1.2 IBA Case

Table 7-15 illustrates the daily and annual costs of operation with the India-Bhutan-Bangladesh cross-border transmission link for each season in different years.

Table 7-15: Daily and Annual Cost of Operation with North-East India-Bangladesh-North India Cross-Border Transmission Link (BAN 6% growth)

Year	Daily cost of operation for the regional base case ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	154.30	150.12	152.91	145.20	54,980.7
2022	176.51	171.39	175.82	166.66	62,996.8
2025	189.39	182.08	188.65	176.67	67,231.6
2027	219.16	212.35	218.20	204.80	77,974.2

Table 7-16 illustrates the economic benefit summary for the study time period of 2020-2030 with the IBA cross-border transmission link.

Table 7-16: Economic Benefit Summary for the Study Period

Period	Present worth ($ millions)				
	Cost of operation of base case	Cost of operation with cross-border transmission link	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2020 - 2030	320,558.30	318,694.36	1,863.94	1,670.93	193.01

The results indicate a net benefit of $193 million for the study period. It can be observed that the cost advantage is reduced when comparing with the original IBA case. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in Appendix F – Annuitized Project Costs and Benefit-Cost.

7.3.1.3 IBABU Case

Table 7-17 illustrates the daily and annual costs of operation with North-East India-Bangladesh-North India cross-border transmission link and India-Bhutan cross-border transmission link.

Table 7-17: Daily and Annual Cost of Operation with North-East India-Bangladesh-North India and India-Bhutan Cross-Border Transmission Links (BAN 6% growth)

Year	Daily cost of operation for the regional base case ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	154.12	150.12	152.33	144.71	54,866.5
2022	176.34	171.39	175.24	166.17	62,883.5
2025	189.18	181.18	188.32	176.25	67,061.5
2027	219.01	211.45	218.06	204.38	77,826.8

Table 7-18 illustrates the economic benefit summary for the study time period of 2020-2030 with the IBA cross-border transmission link and IBU cross-border transmission link.

Table 7-18: Economic Benefit Summary for the Study Period

Period	Present worth ($ millions)				
	Cost of operation of base case	Cost of operation with cross-border transmission link	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2020 - 2030	320,558.30	318,052.73	2,505.57	1,802.63	702.95

The results indicate a net benefit of $703 million for the study period. It can be observed that the cost advantage is reduced when comparing with the original IBABU case. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in Appendix F – Annuitized Project Costs and Benefit-Cost.

7.3.2 Cross-border Transmission Link Power Transfer

7.3.2.1 IBA Case

Table 7-19 and Table 7-20 illustrate how the North India - Bangladesh and North-East India – Bangladesh cross-border transmission links are being utilized in years 2020, 2022, 2025 and 2027 in different seasons.

Table 7-19: Utilization of the North East India-Bangladesh Section of the Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak Transfer hour	Capacity factor (%)
2020	Summer	1885.58	21:00	27.6
	Winter	2663.59	08:00	37.2
	Monsoon	2039.33	21:00	30.9
	Post-Monsoon	2295.80	19:00	33.2
2022	Summer	1930.42	19:00	26.8
	Winter	2663.52	14:00	26.6
	Monsoon	2150.24	21:00	32.4
	Post-Monsoon	2297.86	22:00	32.5
2025	Summer	3372.34	03:00	53.3
	Winter	3610.00	01:00	46.4
	Monsoon	3297.85	19:00	52.0
	Post-Monsoon	3590.98	22:00	51.3
2027	Summer	3172.36	18:00	49.8
	Winter	3514.31	15:00	44.6
	Monsoon	3002.13	05:00	45.4
	Post-Monsoon	3500.87	22:00	53.2

Table 7-20: Utilization of the Bangladesh- North India Section of the Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak transfer hour	Capacity factor (%)
2020	Summer	1125.71	07:00	12.8
	Winter	2663.58	04:00	34.4
	Monsoon	1039.33	07:00	15.5
	Post-Monsoon	2174.58	17:00	24.8
2022	Summer	930.43	07:00	11.1
	Winter	2663.50	04:00	21.8

Year	Season	Maximum Power transfer (MW)	Peak transfer hour	Capacity factor (%)
	Monsoon	1150.24	07:00	17.1
	Post-Monsoon	2208.06	18:00	26.3
2025	Summer	2442.73	07:00	40.3
	Winter	3039.83	04:00	39.7
	Monsoon	2297.85	09:00	38.6
	Post-Monsoon	2771.69	04:00	40.9
2027	Summer	2172.36	07:00	36.1
	Winter	2851.67	04:00	34.0
	Monsoon	2002.13	09:00	31.4
	Post-Monsoon	2500.87	05:00	40.6

It can be observed that both cross-border transmission links are moderately utilized and primarily, the capacity factors are reduced before 2025 due to the lower load in Bangladesh.

7.3.2.2 IBABU case

Table 7-21 and Table 7-22 illustrate how the North India - Bangladesh and North-East India – Bangladesh cross-border transmission links are being utilized in years 2020, 2022, 2025 and 2027 in different seasons.

Table 7-21: Utilization of the North East India-Bangladesh Section of the IBA Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak Transfer hour	Capacity factor (%)
2020	Summer	2718.16	21:00	37.5
	Winter	3419.63	12:00	40.1
	Monsoon	2985.38	21:00	47.8
	Post-Monsoon	3061.39	23:00	49.6
2022	Summer	2820.72	19:00	36.4
	Winter	3009.37	17:00	28.6
	Monsoon	2979.83	08:00	49.2
	Post-Monsoon	3068.70	11:00	49.2
2025	Summer	3693.60	04:00	57.6
	Winter	3692.57	01:00	46.7
	Monsoon	3498.23	05:00	53.9
	Post-Monsoon	3923.59	02:00	57.7
2027	Summer	3338.66	08:00	51.2
	Winter	3831.13	02:00	45.4
	Monsoon	3019.82	05:00	45.9
	Post-Monsoon	3704.85	04:00	56.0

Table 7-22: Utilization of the Bangladesh- North India Section of the IBU Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak transfer hour	Capacity factor (%)
2020	Summer	1718.16	21:00	23.17
	Winter	3136.32	16:00	36.42
	Monsoon	1985.38	21:00	33.97
	Post-Monsoon	2764.81	17:00	38.61
2022	Summer	1820.72	19:00	21.49
	Winter	3009.33	17:00	23.87
	Monsoon	1979.83	08:00	35.46
	Post-Monsoon	3063.57	13:00	39.89
2025	Summer	2693.60	04:00	44.68
	Winter	3039.82	04:00	39.85
	Monsoon	2498.23	05:00	40.57
	Post-Monsoon	2923.59	02:00	48.22
2027	Summer	2338.66	08:00	37.67
	Winter	2851.82	04:00	34.91
	Monsoon	2019.82	05:00	31.88
	Post-Monsoon	2704.85	4:00,10:00	43.18

It can be observed that both transmission links are moderately utilized and primarily, the capacity factors are reduced before 2025 due to the lower load in Bangladesh.

Table 7-23 illustrates how the North-East India – Bhutan cross-border transmission link is being utilized in years 2020, 2022, 2025 and 2027 in different seasons.

Table 7-23: Utilization of the North East India-Bhutan Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak Transfer hour	Capacity factor (%)
2020	Summer	831.00	21:00	54.1
	Winter	1099.90	12:00	60.5
	Monsoon	1100.00	18:00-23:00	94.7
	Post-Monsoon	1100.00	17:00	96.2
2022	Summer	889.11	19:00	53.7
	Winter	1099.41	21:00	41.3
	Monsoon	1100.00	01:00-04:00, 08:00-11:00, 14:00-18:00, 22:00-24:00	99.6
	Post-Monsoon	1100.00	07:00	97.1
2025	Summer	501.30	04:00	37.9
	Winter	765.25	01:00	42.4
	Monsoon	648.52	19:00	48.1
	Post-Monsoon	831.79	22:00	61.3
2027	Summer	416.75	19:00	25.9
	Winter	848.07	02:00	46.5
	Monsoon	497.13	19:00	36.5

Year	Season	Maximum Power transfer (MW)	Peak Transfer hour	Capacity factor (%)
	Post-Monsoon	868.55	22:00	63.3

It can be observed that the cross-border transmission link is well-utilized prior to 2025, and the utilization decreases after 2025.

7.3.3 Generation Dispatch Changes

7.3.3.1 IBA Case

Table 7-24 illustrates several generation dispatch changes for IBA cross-border transmission link.

Table 7-24: Major Generation Dispatch Changes for the IBA Cross-Border Transmission Link

Year	Season	Hydro (MW)		Coal (MW)		Gas (MW)
		India North East	Bhutan	India North	India West	Bangladesh
2022	Monsoon	508.1	98.8	-58.6	-	-331.3
2027	Monsoon	2228.4	70.8	-1299.9	-658.1	-95.6

It can be observed that the cost reduction before 2025 is mainly due to replacement of gas-based power generation in Bangladesh with hydro generation in North-East India and Bhutan. However, after 2025, cost advantage is due to replacement of coal-based power generation in Northern and Western regions of India with hydro in North-East Bangladesh and Bhutan.

7.3.3.2 IBABU Case

Table 7-25 illustrates several generation dispatch changes for IBABU cross-border transmission link.

Table 7-25: Major Generation Dispatch Changes for the IBABU Cross-Border Transmission Links

Year	Season	Hydro (MW)		Coal (MW)		Gas (MW)
		India North East	Bhutan	India North	India West	Bangladesh
2022	Monsoon	578.1	168.8	-378.1	-	-384.4
2027	Monsoon	2111.0	81.1	-1547.9	-563.2	-105.1

It can be observed that the cost reduction before 2025 is mainly due to replacement of gas-based power generation in Bangladesh with hydro generation in North-East India and Bhutan. However, after 2025, cost advantage is due to replacement of coal-based power generation in Northern and Western regions of India with hydro in the North-East India and Bhutan.

7.3.4 Summary

Table 7-26 illustrates the summary of the cost advantage, present worth of project cost and the net profit for the IBA cross-border transmission link in the low load growth scenario of Bangladesh.

Table 7-26: Summary of the IBA North East India—Bangladesh-North India Cross-Border Transmission Link Economic Performance

Period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net profit ($ millions)	Average Capacity (%) factor
2020 - 2030	1,863.94	1,670.93	193.01	40.1/30.1

Table 7-27 illustrates the summary of the cost advantage, present worth of project cost and the net profit for the IBABU cross-border transmission links in the low load growth scenario of Bangladesh.

Table 7-27: Summary of the IBABU, North East India—Bangladesh-North India Cross-Border Transmission Link and India-Bhutan Cross-Border Transmission Link Economic Performance

Period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net profit ($ millions)	Average Capacity (%) factor
2020 - 2030	2,505.57	1,802.63	702.95	46.1/35.8/60.0

7.4 Utilization Improvement of the IBA Cross-border Transmission Link Scenario

The following section presents the results of economic analysis of the cases containing North-East India - Bangladesh – North India (IBA) cross-border transmission link with measures to improve utilization. Reported results include the upgraded lines, daily cost of operation, the annual cost advantage, net benefit, and the utilization of the cross-border transmission link.

7.4.1 Upgraded Lines

It is observed that the network near Gurdaspur (in North India) is strong and capable of handling a transfer of about 5 GW; however, the network near Rangia-Rawta is relatively weak and can be upgraded to facilitate more power transfer in the IBA line. Therefore, the following lines (given in Table 7-28) are upgraded by approximately 300% to observe the improvement of the utilization of IBA cross-border transmission link.

Table 7-28: List of Upgraded Lines

Year	Upgraded Lines					
	From Bus		To Bus		Original Line capacity (MW)	Upgraded Line capacity (MW)
	Name	Number	Name	Number		
2020	Rangia	214004	Balipara-PG	214007	647	1941
	Rangia	214004	Balipara-PG	214007	647	1941
	Chukha	612002	Malbas2	612003	131	393
	Chukha	612002	Bunakha	612004	131	393
	Jigmeling	614005	Semtok2	614006	550	1650
	Jigmeling	614005	Semtok2	614006	550	1650
2022	Semtok2	612006	Rurichu2	612010	131	393
	Biswa-Chari	214002	Balipara-PG	214007	800	2400
	Biswa-Chari	214002	Balipara-PG	214007	800	2400
2025	Rangia	214004	Tawang PP	274005	800	2400
	Rangia	214004	Tawang PP	274005	800	2400
	Biswa-Chari	214002	Balipara-PG	214007	800	2400
	Biswa-Chari	214002	Balipara-PG	214007	800	2400
2027	Samaguri2	212007	Sonabil	212025	131	393
	Samaguri2	212007	Sonabil	212025	131	393

7.4.2 Cost of Operation

Table 7-29 presents daily and annual costs of operation with IBA cross-border transmission link (with network upgrades) for each season of the study years.

Table 7-29: Daily and Annual Cost of Operation with the Cross-Border Transmission Link

Year	**Daily cost of operation for the IBA-Upgraded case ($ millions)**				**Annual cost ($ millions)**
	Summer	Winter	Monsoon	Post-Monsoon	
2020	165.31	161.09	163.49	155.67	58,909.13
2022	189.65	183.93	187.88	178.51	67,523.96
2025	206.40	195.95	204.40	191.38	72,831.21
2027	237.20	226.67	236.14	221.52	84,092.04

As per the results, it can be seen that the daily cost of operation in each year is increased, as the demand is increased. Table 7-30 shows the economic benefit summary with the North-East India – Bangladesh – North India cross-border transmission link from 2020-2030 with the network upgrades.

Table 7-30: Economic Benefit Summary for the Study Period

Period	**Present worth ($ millions)**				
	Cost of operation of base case	Cost of operation with cross-border transmission link	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2020 - 2030	346,682.81	342,817.82	3,864.99	1,901.12	1,963.87

The cost advantage in this case ($3,864.99 million) is considerably increased compared to the cost advantage of the original IBA case ($3,580.30 million). However, the results indicate a net benefit of $1,963.87 million for the study period. This net benefit is only slightly higher compared to the net benefit of the original IBA project ($1909.37 million), as the network upgrade costs are also incorporated into this sensitivity analysis. A complete description of annuitized cost calculation (using a 10% discount rate), and the benefit estimation can be found in Appendix F – Annuitized Project Costs and Benefit-Cost Ratios

7.4.3 Cross-border Transmission Link Power Transfer

Table 7-31 and Table 7-32 show the utilization of North-East India – Bangladesh section (Rangia/Rowta – Barapukuria) and the Bangladesh - North India section (Barapukuria - Gurdaspur) of the IBA cross-border transmission link in years 2020, 2022, 2025 and 2027 in different seasons.

Table 7-31: Utilization of the North East India - Bangladesh Section of the Cross-Border Transmission Link

Year	**Season**	**Maximum Power transfer (MW)**	**Peak Transfer hour**	**Capacity factor (%)**
2020	Summer	3928.98	21:00	50.7
	Winter	2648.63	08:00	22.8
	Monsoon	4661.23	24:00	55.1
	Post-Monsoon	4848.65	01:00	46.6
2022	Summer	4545.42	18:00	67.7
	Winter	2657.48	14:00	21.4
	Monsoon	4640.67	01:00	63.3
	Post-Monsoon	4965.08	02:00	54.4
2025	Summer	3498.45	03:00	56.4
	Winter	2442.74	23:00	26.4
	Monsoon	3534.12	05:00	57.1
	Post-Monsoon	6000.00	0:00, 24:00	70.2
2027	Summer	3394.33	22:00	53.6
	Winter	3031.76	13:00	28.5
	Monsoon	3530.15	05:00	57.0
	Post-Monsoon	6000.00	0:00,24:00	70.0

Table 7-32: Utilization of the Bangladesh - North India Section of the Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak transfer hour	Capacity factor (%)
2020	Summer	2975.51	07:00	44.5
	Winter	3275.24	04:00	46.0
	Monsoon	2480.08	08:00	48.1
	Post-Monsoon	3213.06	04:00	48.0
2022	Summer	2801.82	08:00	43.6
	Winter	3231.81	04:00	42.1
	Monsoon	2784.73	08:00	44.6
	Post-Monsoon	3121.23	17:00	52.3
2025	Summer	4247.88	07:00	67.5
	Winter	3648.73	04:00	55.1
	Monsoon	4167.64	09:00	67.2
	Post-Monsoon	5068.14	04:00	79.1
2027	Summer	3654.70	07:00	56.5
	Winter	2918.78	04:00	41.0
	Monsoon	3654.62	09:00	57.2
	Post-Monsoon	4752.52	04:00	78.2

When the IBA cross-border transmission link utilization is compared with and without the internal line upgrades, it can be observed that with the internal line upgrades, the average cross-border transmission link utilization increases from 37.5% to 52.3%. In addition, with the increasing demand in Bangladesh and North India, power transfer in the cross-border transmission link shows an increment, utilizing the cross-border transmission link more in years, 2025 and 2027.

7.5 IBA Cross-border Transmission Link with Bareilly Terminal Scenario

The following section presents the results of economic analysis of the cases containing IBA cross-border transmission link. In this scenario, North India terminal of the IBA cross-border transmission link is changed from Barapukuria - Gurdaspur to Barapukuria – Bareilly. Reported results include the daily cost of operation, the annual cost advantage, net benefit, and the utilization of the cross-border transmission link.

7.5.1 Cost of Operation

Table 7-33 presents the daily and annual costs of operation with the India-Bangladesh cross-border transmission link for each season of the studied years.

Table 7-33: Daily and Annual Cost of Operation with the Cross-Border Transmission Link

Year	Daily cost of operation for the regional upgraded case ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	165.59	161.10	164.09	156.13	59,032.90
2022	189.91	183.91	188.49	179.06	67,652.02
2025	203.76	195.84	204.55	192.12	72,662.00
2027	237.12	226.54	236.35	222.09	84,143.59

As per the results, it can be observed that the daily cost of operation in each season increases, as the demand increases.

Table 7-34 illustrates the economic benefit summary with the North East India – Bangladesh – North India cross-border transmission link from 2020-2030.

Table 7-34: Economic Benefit Summary for the Study Period

Period	Present worth ($ millions)				
	Cost of operation of base case	Cost of operation with cross-border transmission link	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2020 - 2030	346,682.81	343,102.93	3,579.87	1,670.93	1,908.95

The results indicate a net benefit of $1,908.95 million for the study period. The net benefit is similar to the original IBA case ($1909.37 million). A complete description of annuitized cost calculation (using a 10% discount rate), and the benefit estimation can be found in Appendix F – Annuitized Project Costs and Benefit-Cost Ratios.

7.5.2 Cross-border Transmission Link Power Transfer

Table 7-35 and Table 7-36 show the utilization of North-East India – Bangladesh section (Rangia/Rowta – Barapukuria) and the Bangladesh - North India section (Barapukuria - Bareily) of the IBA cross-border transmission link in years 2020, 2022, 2025 and 2027 in different seasons.

Table 7-35: Utilization of the Bangladesh- North India Section of the Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak Transfer hour	Capacity factor (%)
2020	Summer	3334.58	08:00	25.3
	Winter	3367.06	06:00	26.3
	Monsoon	3085.59	08:00	26.0
	Post-Monsoon	3462.72	14:00	37.5
2022	Summer	2166.55	08:00	11.6
	Winter	4039.49	03:00	31.5
	Monsoon	2118.60	08:00	11.9
	Post-Monsoon	2876.02	08:00	30.2
2025	Summer	3786.56	04:00	59.1
	Winter	3958.36	05:00	57.1
	Monsoon	4323.14	19:00	63.6
	Post-Monsoon	4040.75	18:00	59.9
2027	Summer	4157.09	07:00	57.4
	Winter	4196.80	05:00	51.3
	Monsoon	4114.71	19:00	56.5
	Post-Monsoon	4161.47	18:00	62.0

Table 7-36: Utilization of the North East India-Bangladesh Section of the Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak transfer hour	Capacity factor (%)
2020	Summer	1950.69	21:00	29.0
	Winter	1632.70	08:00	14.6
	Monsoon	2040.39	21:00	30.3
	Post-Monsoon	2287.64	21:00	27.7
2022	Summer	1930.81	19:00	27.5
	Winter	1808.29	13:00	17.4
	Monsoon	2151.69	21:00	31.6
	Post-Monsoon	2150.04	17:00	29.5
2025	Summer	3380.33	03:00	54.6
	Winter	2620.86	06:00	30.0
	Monsoon	3456.89	21:00	53.6
	Post-Monsoon	3596.70	21:00	53.5
2027	Summer	3395.02	19:00	53.0
	Winter	3507.44	14:00	37.3
	Monsoon	3546.81	20:00	52.5
	Post-Monsoon	3760.80	21:00	53.6

In general, IBA cross-border transmission link is moderately utilized to transfer power from North-Eastern India to Bangladesh in all seasons. With the increasing demand in Bangladesh and North India, power transfer in the cross-border transmission link shows an increment, utilizing the cross-border transmission link in year 2025 and 2027. With the new terminal at Bareilly, IBA line utilization is not significantly improved.

7.6 ISL Cross-Border Transmission Link with High LNG Penetration in Sri Lanka Scenario

The following section presents the economic analysis of the ISL cross-border transmission link with the high LNG penetration in Sri Lankan power system. The Sri Lankan power system model is modified for this sensitivity study using the natural gas high penetration case in the report "Generation Expansion Plan-2014" by CEB. Reported results include the daily cost of operation, the annual cost advantage, net benefit, and the utilization of the cross-border transmission link.

7.6.1 Cost of Operation

Table 7-37 represents the daily and annual costs of operation with the India-Sri Lanka cross-border transmission link (high LNG) for each season in different years with the implementation of the new gas based power plants.

Table 7-37: Daily and Annual Cost of Operation with the Cross-Border Transmission Link

Year	Daily cost of operation with the cross-border transmission link ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2020	166.93	161.48	165.24	157.27	59,398.43
2022	191.00	184.30	189.47	180.10	67,971.61
2025	206.63	197.48	207.48	194.90	73,591.76
2027	240.01	227.87	239.23	225.01	85,057.02

Table 7-38 illustrates the economic benefit summary for the study period from year 2020-2030 with India - Sri Lanka cross-border transmission link.

Table 7-38: Economic Benefit Summary for the Study Period

Period	Present worth ($ Millions)				
	Cost of operation of base case	Cost of operation with cross-border transmission link	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2020 - 2030	345,942.16	346,723.68	781.52	255.17	526.35

The results indicate a net benefit of $526.35 million for the study period, which is an increase compared to the net benefit ($495 million) of the original ISL case. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in Appendix F – Annuitized Project Costs and Benefit-Cost Ratios.

7.6.2 Cross-border Transmission Link Power Transfer

The following Table 7-39 presents the utilization of the India – Sri Lanka cross-border transmission link in years 2020, 2022, 2025 and 2027 in average different seasons.

Table 7-39: Utilization of the India-Sri Lanka Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak Transfer hour	Capacity factor (%)
2020	Summer	499.99	17:00, 19:00	64.6
	Winter	499.99	09:00	83.8
	Monsoon	499.99	23:00	77.4
	Post-Monsoon	499.99	18:00	75.0
2022	Summer	499.99	11:00	87.6
	Winter	500.00	08:00	52.5
	Monsoon	499.99	07:00	90.9
	Post-Monsoon	500.00	19:00	91.9
2025	Summer	499.99	18:00	53.1
	Winter	497.17	6:00, 16:00-18:00, 22:00-23:00	65.5
	Monsoon	500.00	12:00	77.1
	Post-Monsoon	500.00	23:00	62.7
2027	Summer	499.99	07:00	66.8
	Winter	500.00	9:00-10:00	90.8
	Monsoon	500.00	16:00	63.8
	Post-Monsoon	498.94	19:00	66.4

India – Sri Lanka cross-border transmission link is efficiently utilized to transfer power from India to Sri Lanka and vice versa in all seasons. In the year 2022 monsoon and post-monsoon seasons, due to the high availability hydro power, Sri Lanka transfers power to India, utilizing the maximum capacity of the cross-border transmission link. However, with the increasing demand and the new addition of gas-based power stations in Sri Lanka (in years 2025 and 2027), it consumes more power from India. Irrespective of the power transfer direction, lower-cost coal/hydro power from one country is used instead of diesel, gas and coal based power generation in the other country.

In conclusion, the main cost advantage in this case study is attained as a result of high power transfer from India to Sri Lanka instead of using expensive LNG in Sri Lanka to meet the high demand with an average capacity factor of 73.11%.

7.7 Simultaneous Operation of IBABU and IN12 Cross-Border Transmission Links Scenario

Power generation of Northern India is primarily based on expensive thermal power generation, and inexpensive energy sources can be vital to meet the increasing power demand.

The study results have revealed that the inclusion of the IBA cross-border transmission link along with IBU cross-border transmission link reduces the total cost of operation of the regional network. Similarly, both India-Nepal cross-border transmission links (IN1 and IN2) are efficiently utilized. Therefore, in this study, inclusion of India – Nepal transmission links (link 1 and 2) along with the IBABU cross border transmission link is investigated.

The following section presents the economic analysis of the IBABU, IN1 and IN2 cross-border transmission links when all three transmission lines are in simultaneous operation.

7.7.1 Cost of Operation

Table 7-40 represents the daily and annual costs of operation with the IBABU and IN12 cross border transmission links for each season in year 2025 and 2027.

Table 7-40: Daily and Annual Costs Of Operation with the Cross-Border Transmission Links

Year	Daily cost of operation with the cross-border transmission link ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2025	201.59	194.12	202.29	189.65	74,131.61
2027	235.36	224.85	234.04	219,83	83,409.75

Table 7-41 illustrates the economic benefit summary for the study period from year 2025-2030 with IBABU and IN12 cross-border transmission links.

Table 7-41: Economic Benefit Summary for the Study Period

Period	Present worth ($ Millions)				
	cost of operation of base case	cost of operation with cross-border transmission link	Cost Advantage	Annuitized capital cost for the study period	Net benefit ($ millions)
2025 - 2030	163,977.79	160,127.94	3,849.85	949.31	2,900.54

The results indicate a net benefit of $2,900.54 million for the study period. A complete description of the annuitized cost calculation (using a 10% discount rate) and the benefit estimation can be found in the Appendix F – Annuitized Project Costs and Benefit-Cost Ratios.

7.7.2 Cross-border Transmission Link Power Transfer

The following Table 7-42 and Table 7-43 present the utilization of the North-East India - Bangladesh cross-border transmission link in years 2025 and 2027 in different seasons.

Table 7-42: Utilization of the Bangladesh - North India Section of the IBA Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak Transfer hour	Capacity factor (%)
2025	Summer	45.55	7:00	73.39
	Winter	36.95	4:00	56.63
	Monsoon	46.66	5:00	78.30
	Post-Monsoon	49.95	4:00	80.95
2027	Summer	36.23	7:00	58.62
	Winter	29.18	4:00	42.01
	Monsoon	40.53	9:00	66.20
	Post-Monsoon	47.57	4:00	76.38

Table 7-43: Utilization of the North-East India – Bangladesh Section of the IBA Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak Transfer hour	Capacity factor (%)
2025	Summer	40.16	21:00	61.73
	Winter	30.55	10:00	30.55
	Monsoon	44.82	21:00	68.18
	Post-Monsoon	67.53	22:00	67.53
2027	Summer	42.50	20:00	59.64
	Winter	32.07	13:00	32.07
	Monsoon	45.91	23:00	66.38
	Post-Monsoon	45.57	2:00	66.46

North-East India – Bangladesh – North India cross-border transmission link is moderately utilized in all seasons. However, the capacity factors of both sections of the cross-border transmission links are not significantly increased in this scenario compared to the IBABU case. In general, winter capacity factors are significantly less due to low hydro availability.

The following Table 7-44 presents the utilization of the North-East India – Bhutan cross-border transmission link in years 2025 and 2027 in different seasons.

Table 7-44 : Utilization of the North India – Bhutan Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak Transfer hour	Capacity factor (%)
2025	Summer	3.34	21:00	46.37
	Winter	3.88	21:00	40.37
	Monsoon	5.17	23:00	78.52
	Post-Monsoon	5.50	21:00	80.95
2027	Summer	4.06	20:00	42.37
	Winter	4.24	13:00	44.88
	Monsoon	5.50	20:00-21:00, 23:00	78.90
	Post-Monsoon	5.50	2:00, 21:00-23:00	83.64

Addition of the India – Nepal (IN1 and IN2) cross-border transmission links to the IBABU scenario does not have a significant impact on the utilization of the India - Bhutan (IBU) cross-border transmission link.

The following Table 7-45 and Table 7-46 present the utilization of the North India – Nepal cross-border transmission links in years 2025 and 2027 in different seasons.

Table 7-45: Utilization of the North India – Nepal 1 Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak Transfer hour	Capacity factor (%)
2025	Summer	6.00	1:00 -24:00	100.00
	Winter	6.00	1:00 -24:00	100.00
	Monsoon	8.80	1:00 -24:00	100.00
	Post-Monsoon	6.00	02:00, 07:00-12:00, 17:00	100.00
2027	Summer	6.00	1:00 -24:00	100.00
	Winter	6.00	1:00 -24:00	100.00

	Monsoon	6.00	1:00 -24:00	100.00
	Post-Monsoon	6.00	1:00 -24:00	100.00

Table 7-46: Utilization of the North India – Nepal 2 Cross-Border Transmission Link

Year	Season	Maximum Power transfer (MW)	Peak Transfer hour	Capacity factor (%)
2025	Summer	10.00	01:00-20:00, 22:00-24:00	100.00
	Winter	10.00	1:00 -24:00	100.00
	Monsoon	10.00	01:00-20:00	98.88
	Post-Monsoon	10.00	01:00-19:00, 21:00-24:00	100.00
2027	Summer	10.00	1:00-19:00	96.56
	Winter	10.00	1:00 -24:00	100.00
	Monsoon	10.00	1:00 - 20:00	97.87
	Post-Monsoon	10.00	1:00-19:00, 22;00-24;00	99.64

Throughout 2025 and 2027, both IN1 and IN2 are utilized close to maximum capacity, enabling high power transfer from Nepal to India.

7.7.3 Summary

Table 7-47 illustrates the summary of the cost advantage, present worth of project cost and the net profit for the IBABU and IN12 cross-border transmission links simultaneous operation scenario.

Table 7-47: Summary of the IBABU and IN12 Cross-Border Transmission Links Simultaneous Operation Economic Performance

Period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net profit ($ millions)	Average Capacity (%) factor
2025 - 2030	3,849.85	949.31	2,900.54	66.6/56.6/62/ 100/99.1

7.8 All Cross-border Transmission Links Connected Scenario

The following section presents the results of the economic analysis of the power system upon connecting all cross-border transmission links listed below. This case-study is conducted for the study period of year 2025 to year 2027. Reported results include the daily cost of operation, the annual cost advantage, and present worth of net benefit and the utilization of each cross-border transmission link.

The potential cross-border transmission links identified for the analysis are the following:

1. Rangia/Rowta (India) - Barapukuria (Bangladesh) – Gurudaspur (India);
2. Bareilly (India) - Upper Karnali (Nepal);
3. Gorakhpur (India) - Marsyangdi (Nepal);
4. Rangia/Rowta (India) - Yangbari (Bhutan)
5. Madurai (India) - New Anuradhapura (Sri Lanka);
6. Amritsar (India) - Lahore (Pakistan);
7. Arghandi (Afghanistan) – Peshawar (Pakistan);
8. Roghun (Tajikistan) – Peshawar (Pakistan).

7.8.1 Cost of Operation

Table 7-48 presents the daily and annual costs of operation with all cross-border transmission links for each season of the studied years.

Table 7-48: Daily and Annual Cost Of Operation with All Cross-Border Transmission Links

Year	Daily cost of operation for the case with all cross-border transmission link ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
2025	200.85	193.46	200.98	188.58	71,527.97
2027	234.82	224.59	233.34	219.41	83, 235.44

Table 7-49 presents the present worth of annual cost advantage, annualized project cost and the net benefit for each cross-border transmission link of the study period from year 2025 to year 2027.

Table 7-49: Present Worth Of Annual Cost Advantage, Project Cost and Net Benefits of the Cross-Border Transmission Links

Cross-border transmission link	Costs in ($)		
	Present worth of annual cost advantage	Annualized Project Cost	Net Benefit
IBA	2,306,581,936.42	695,705,614.29	1,610,876,322.14
IBU	438,125,428.88	54,833,940.04	383,291,488.84
IN1	1,162,003,475.08	116,522,122.59	1,045,481,352.49
IN2	1,323,155,254.00	82,250,910.06	1,240,904,343.93
IPA	960,004,385.30	70,770,053.87	889,234,331.44
IFPA	142,504,135.35	102,813,637.58	39,690,497.77
PATJ	437,558,457.56	174,783,183.89	262,775,273.67
IS	455,097,031.09	106,240,758.83	348,856,272.26
All Links	4,342,105,802.96	1,403,920,221.15	2,938,185,581.81

The results indicate a net benefit of \$ 2,938.19 million for the study period, and the annuitized cost calculation is conducted using a 10% discount rate.

7.8.1.1 Cross-border Transmission Link Power Transfer

The following Table 7-50 presents the average utilization of the cross border links from year 2025 to year 2027.

Average cross border utilization was calculated using the following formula:

$$Average\ Cross\ Border\ Link\ Capacity\ factor\ for\ study\ period$$

$$= \frac{\sum Averaged\ anual\ capacity\ factor\ for\ each\ year}{Number\ of\ Years}$$

Table 7-50: Average Cross-Border Link Capacity Factor from Year 2025 to Year 2030

Cross-border Transmission Link		Average Capacity Factor (%)
IBA	North India to Bangladesh	66.4
	Bangladesh to India	56.8
IPA		68.5
PATJ		0.0
IS		55.1
IN1		89.3
IN2		99.5
IBU		76.3
AFPA		56.8

Figure 7-1 represents a comparison of economic benefit (present worth) with all the studied cases from year 2025 to year 2030.

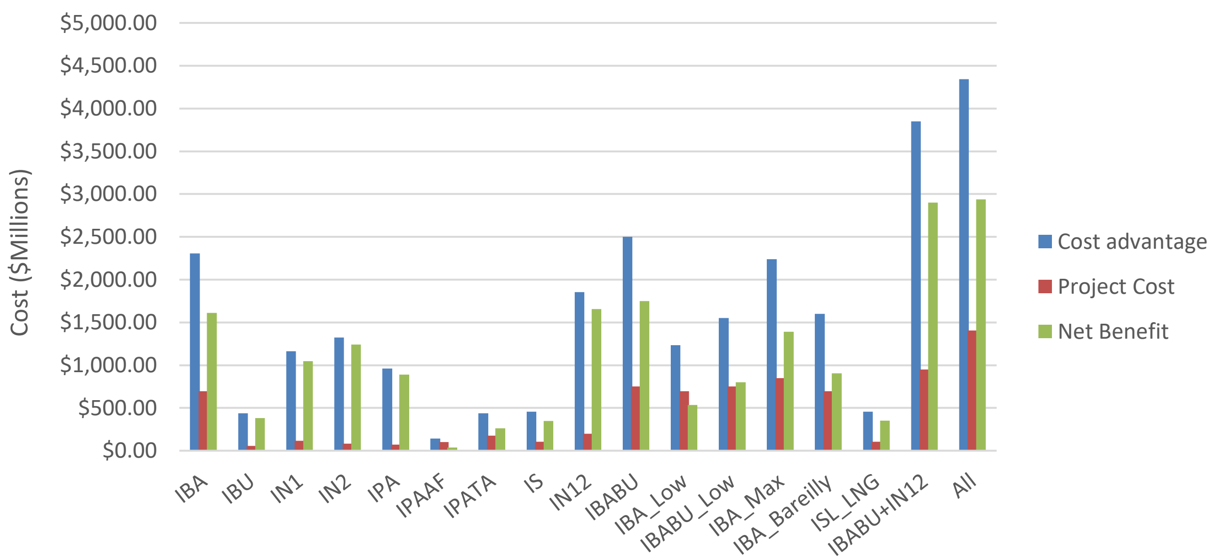

Figure 7-1: Comparison of Economic Benefit (Present Worth) with All Studied Cases from 2025 to 2030

7.9 Summary of Results: Sensitivity Scenarios

Table 7-51 presents the summary of results of all studied sensitivity scenarios.

Table 7-51: Summary of Results of All Cross-Border Transmission Links Scenarios

Study case	Study period	Present worth of the cost advantage ($ Millions)	Present worth of annuitized project cost ($ Millions)	Net benefit ($ millions)	Average Capacity Factor (%)
IN12	**2025-2030**	1853.49	198.77	1,654.72	100.0/99.2
IBABU	2020-2030	4103.17	1802.63	2300.54	46.2/51.1/62.8
IBA (Low Load)	2020-2030	1,863.94	1,670.93	193.01	40.1/30.1
IBABU (Low Load)	2020-2030	2,505.57	1,802.63	702.95	46.1/35.8/60.0
IBA max	2020-2030	3,864.99	1,901.12	1,963.87	52.3
IBA Bareilly	2020-2030	3,579.87	1,670.93	1,908.95	37.2
ISL High LNG	2020-2030	781.52	255.17	526.35	73.1
IBABU+IN12	**2025-2030**	3,849.85	949,31	2,900.54	Refer to section 7.7
All Links	**2025-2030**	4,342.11	1,403.92	2,938.19	Refer to Table 7-50

Figure 7-2 represents a comparison of economic benefit (present worth value) of all cross-border scenarios considered under the sensitivity study.

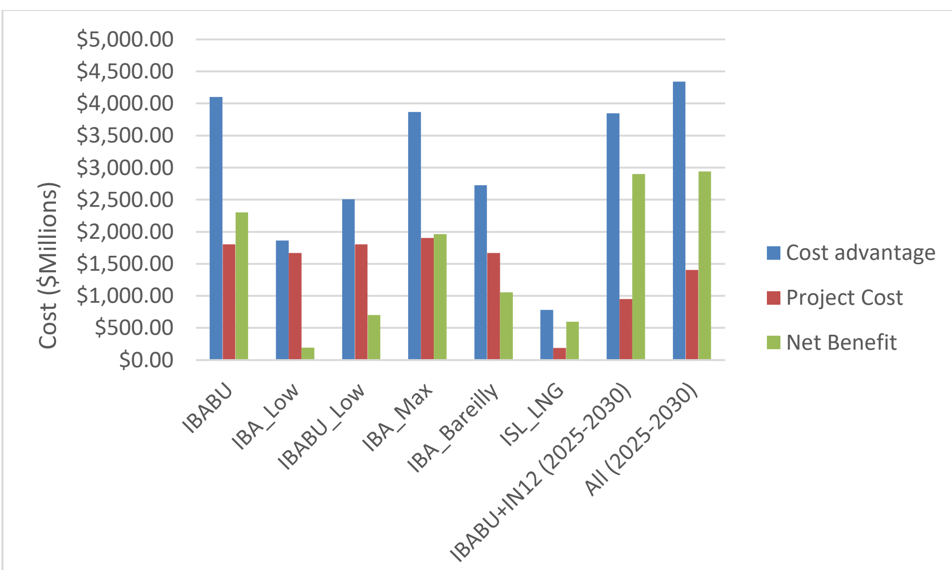

Figure 7-2: Cross-border Transmission Links Power Transfer – Sensitivity Study Results

8 Conclusions

A comprehensive study of transmission development opportunities among participating countries in South Asia was carried out. As a part of the study, the economic analysis methodology was developed, and the economic planning software tool was implemented and validated. The data collection process to obtain the input data for the economic model was completed, and the economic impact of each cross-border transmission link was carried out.

8.1 Economic Analysis

- The methodology was developed to study a number of cross-border power transfer cases based on the identified potential cross-border power transfer projects. The summary of the methodology is presented below:
    - Initially, the base cases (with feasible steady state solutions) were developed for the years 2022 and 2027. Following this, the base cases for 2020 and 2025 were derived based on the available load forecast data and generation development/retirement plans.
    - Each potential cross-border transmission link was included separately into the base cases to obtain interconnected cases, and their economic impact was analyzed. In addition, several sensitivity scenarios were identified and were further analyzed based on the preliminary results.
- A Multi-Period DC Optimal Power Flow (MP-DCOPF) program was developed to calculate the expected costs of operation for each given case. The program calculates the optimum cost of operation for a given daily load pattern.
- All base cases and interconnected cases were analyzed using the MP-DCOPF program to obtain the operating costs and corresponding transmission upgrades required for feasible operation.
- The net economic benefit of the cross-border transmission link was calculated as the difference of the operating cost advantage of the study period (2020 to 2030) and the portion of the cost of the transmission link to be recovered within the study period. This portion was calculated by annuitizing transmission investment over its lifespan and calculating the portion of the capital cost recovery during the study period. In this study, the life spans of HVAC and HVDC transmission links were assumed to be forty (40) years. All costs and benefits were converted to the present worth using a discount rate of 10%. A description of the capital cost estimation is given in Appendix G – Transmission Cross-Border Capital Cost Estimations

8.2 Data Collection Process

- Input data for the economic planning software can be categorized as following:
    - **Load related data:** Distribution of load, annual load forecast and the daily load curves representing an average day for each season of the year.
    - **Generation related data:** Ratings of generation which will be in service or are planned to be in service during the study years, technology mix of generators, and the availability factors for each technology type of generators in each season.
    - **Network related data:** Network topology, transmission line and transformer parameters and ratings.

- Most of the input data were collected from the PSS/E base cases. The remaining data were collected from planning reports and discussions with system experts in individual countries. In the final database, many data irregularities, data conflicts and data gaps were identified. These data issues were addressed with suitable assumptions in consultation with experts in individual countries. A complete list of assumptions is given in Appendix K - Assumptions.

8.3 Case Study Results

The daily cost of operation for each season was obtained using the optimized models for study years 2020, 2022, 2025 and 2027. The annual operating costs were calculated using the four daily costs of operation for four seasons[4] (summer, winter, monsoon and post-monsoon) of the year. Annual cost advantages were extrapolated to obtain the total cost advantage for the study period from 2020 to 2030.

The net benefit of the transmission link was calculated as the difference of the cost advantage of the study period (2020 to 2030) and the portion of the cost of the transmission link to be recovered within the study period. This portion was calculated by annuitizing transmission investment over its life span.

The main findings of the study are summarized in Table 8-1.

[4] Each season is assumed to have equal duration (3 months)

Table 8-1: Cross-border Power Transfer Results Summary

	Study case	Study period	Cost Advantage ($ millions)	Annuitized capital cost for the study period ($ millions)	Net benefit ($ millions)	Net benefit/ capital cost for the study period (%)	Average Capacity Factor (%)
Individual Study Cases	IBA	2020-2030	3,580.30	1,670.93	1,909.37	114	37.6
	IBU	2020-2030	719.97	131.7	588.27	446	16.7
	IN1	2020-2030	2,003.02	279.86	1,723.16	615	81.1
	IN2	**2025-2030**	1,323.16	82.25	1,240.90	1507	98.2
	ISL	2020-2030	750.72	255.17	495.56	194	75.1
	IPA	2020-2030	1,492.39	169.97	1,322.42	777	85.4
	AFPA	2020-2030	262.13	246.94	15.2	6	51.8
	PATJ	2020-2030	704	419.79	284.21	67	7.8
Sensitivity Scenarios	IN12	**2025-2030**	1,852.47	198.77	1,653.72	832	100.0/99.2
	IBABU	2020-2030	4,103.17	1,802.63	2300.54	128	46.2/51.1/62.8
	IBA (Low Load)	2020-2030	1,863.94	1,670.93	193.01	12	40.1/30.1
	IBABU (Low Load)	2020-2030	2,505.57	1,802.63	702.95	39	46.1/35.8/60.0
	IBA max	2020-2030	3,864.99	1,901.12	1,963.87	103	52.3%
	IBA Bareilly	2020-2030	3,579.87	1,670.93	1,908.95	114	37.23%
	ISL High LNG	2020-2030	781.52	255.17	526.35	206	73.11%
	IBABU+IN12	**2025-2030**	3,849.85	949.31	2,900.54	306	Refer to section 7.7
	All Links	**2025-2030**	4,342.11	1,403.92	2,938.19	209	Refer to Table 7-50

- North East India-Bangladesh-North India cross-border transmission link (IBA): IBA showed an economic benefit of $1,909 million. The cost advantage is mainly due to the replacement of higher cost coal-based power generation in the Northern and Western India with hydro power in North-Eastern India. The cross-border transmission link is moderately utilized, and the utilization can be improved further by upgrading the transmission network near the terminals.

- India - Bhutan cross-border transmission link (IBU): IBU showed an economic benefit of $587 million. This cross-border transmission link is only slightly utilized in all seasons, as both regions are mostly using hydro power, and the transmission system is not developed enough to effectively evacuate the power to load centers in the rest of India. Therefore, this cross-border transmission link is studied in tandem with the IBA case as a sensitivity study.

- The sensitivity scenario with IBABU (North East India-Bangladesh-Bhutan: IBA and India-Bhutan: IBU cross-border transmission links) shows the largest economic benefit of $1,909 million for the study period of 2020-2030. The cost saving is due to the replacement of higher cost coal-based power generation in the Northern/Western India and gas-based power generation in Bangladesh with hydro power in North-Eastern India and Bhutan.

- The sensitivity scenario with IN12 (India-Nepal cross-border transmission link using both Gorakhpur to Marsyangdi: IN1 and Bareilly to Upper Karnali: IN2 cross-border transmission links) also shows a large economic benefit of $1,654 million for the study period of 2025-2030. Results show that the individual cases of IN1 and IN2 are also highly profitable, with net benefits of $1,723 million (2020-2030) and $1,241 million (2025 – 2030), respectively. The savings in all these cases are mainly due to the replacement of expensive gas and coal-based power in the Northern region with cheaper hydro power from Nepal.

- The sensitivity scenario considering low load growth in Bangladesh shows economic benefits of $193 million and $703 million for IBA and IBABU cases, respectively. The amount of gas-based power generation dispatched in Bangladesh in the base case of low load scenario is comparatively low. Therefore, the economic benefits are reduced compared to the regular load growth scenario, as a smaller amount of gas-based power generation is replaced with hydro in the North-East India and Bhutan.

- After 2025, a large number of coal and hydro-based power plants (e.g. BASHA-1, BASHA-2, BUNJI, etc.) are to be commissioned in Pakistan. When these projects are incorporated, the following implications can be drawn based on the results:

    - Power direction is reversed in AFPA (Afghanistan - Pakistan) and IPA (India – Pakistan) cross-border transmission links. The imports from Turkmenistan and Uzbekistan are not utilized, and cheaper generators from Pakistan are dispatched. The benefit of the IPA project is increased, as the cheaper hydro and coal-based power from Pakistan is injected to India.
    - Utilization of PATJ (Pakistan-Tajikistan) transmission link is heavily reduced, as the generation in Pakistan becomes generally cheaper than the sale price (7 ¢/kWh) of Tajikistan import.
    - Planned generation in Pakistan has to be carefully reviewed and confirmed to validate the above conclusions.

- India – Sri Lanka HVDC cross-border transmission link shows an economic benefit of $495 million. The power flow direction is from India to Sri Lanka in the peak load hours of Sri Lanka, and the direction is reversed in the off-peak hours. The results indicate that the cost advantage is mainly due to the replacement of diesel and coal-based power generation in Sri Lanka with coal-based power in India in the peak load period. In the off-peak period, the cost advantage is due to the replacement of gas and coal-based power generation in India with coal based power in Sri Lanka.

- The sensitivity scenario with improved utilization of IBA cross-border transmission link (after upgrading the fully-utilized transmission lines near Rangia/Rawta) shows an economic benefit of $1,964 million for the study period (2020-2030). This economic benefit is only slightly higher compared to the net benefit of the original IBA project ($1909 million), as the network upgrade costs are also incorporated into this sensitivity analysis. However, with the fully utilized transmission line upgrade near Rangila/Rawta area, IBA cross-border transmission link average utilization factor is increased from 37.5% to 52.3%.

- The sensitivity scenario with IBA cross-border transmission link having Bareilly terminal shows an economic benefit of $1,909 million for the study period, which is similar to the original IBA case ($1,909 million). In addition, IBA cross-border transmission link is moderately utilized to transfer power from North-Eastern India to Bangladesh in all seasons and with the new terminal at Bareilly, the IBA line utilization is not significantly improved.

- The sensitivity scenario with the high LNG penetration in Sri Lankan power system (as per the "Generation Expansion Plan -2014" by CEB) shows an economic benefit of $526 million for the study period, which is an increase compared to the net benefit ($495 million) of the original ISL case. The main cost advantage in this case study is attained as a result of high power transfer from India to Sri Lanka instead of using expensive LNG in Sri Lanka to meet the high demand with an average capacity factor of 73.1%. Irrespective of the power transfer direction, lower-cost coal/hydro power from one country is used instead of diesel, gas and coal-based power generation in the other country.

- The sensitivity scenario with IBABU (North East India-Bangladesh-Bhutan: IBA and India-Bhutan: IBU cross-border transmission links) and IN12 shows an economic benefit of $2,900.5 million for the study period of 2025-2030. The cost saving is due to the replacement of higher cost coal-based power generation in the Northern/Western India and gas-based power generation in Bangladesh with hydro power in Bhutan and Nepal.

- The sensitivity scenario with all the cross-border transmission links in service shows an economic benefit of $2,938.19 million for the study period (2025-2030). Compared to the net benefit of individual cross-border transmission links for the period of 2025-2030, the scenario with all the cross-border transmission links in service shows the highest net benefit.

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10 Appendix A - Power System Overview

In this section, the power system overview of each country is discussed. Load, generation and transmission system summary of years 2022 and 2027 in each power system are presented. The collection of data was divided in three categories: load, generation and transmission. Each category is presented by country.

The collected load data include the load forecast which has been estimated using the power system planning reports of each country and the PSS/E™ simulation cases. The daily load curves for each season, which shapes the daily behaviour of each individual load in the economic model, are also collected.

The generation data consist of the total capacity of generation for the study years, the generation mix, and the availability factors. The total capacity of the generation are calculated using the PSS/E simulation cases as a starting point. The generation in the cases is modified to include future power plants that are relevant to the study. Each case is also modified when the generation retirement plans are available from planning reports. The PSS/E simulation cases do not have information about the technology for each generator. Thus, a mapping process of the PSS/E generation with acquired information from power system planning reports and Internet databases [8], [9] is carried out. However, a small amount of generation content could not be mapped, so best efforts were made considering the specific circumstances to classify that content. The availability factor of a generator represents its possibility of utilization during a given season. Whether the generator is actually utilized or not is irrelevant. If no data are available, these factors for the country are chosen similar to the closest Indian region. If the assumed availability factors violate the power balance constraint, they are modified until a feasible solution is found.

The transmission system data are obtained using the PSS/E cases. If the PSS/E case that represents the year of the study is not available, the available case year closest to the study year is used. In those situations, the case is modified by adding high-voltage transmission links with known commissioning dates (if any) to represent the correct transmission system.

10.1 Power System of Bangladesh

10.1.1 Load

The main source of information for the estimation of the load is the Power System Master Plan 2010 for Bangladesh [2] and the PSS/E cases. Figure 10-1 shows the estimated load forecast of Bangladesh.

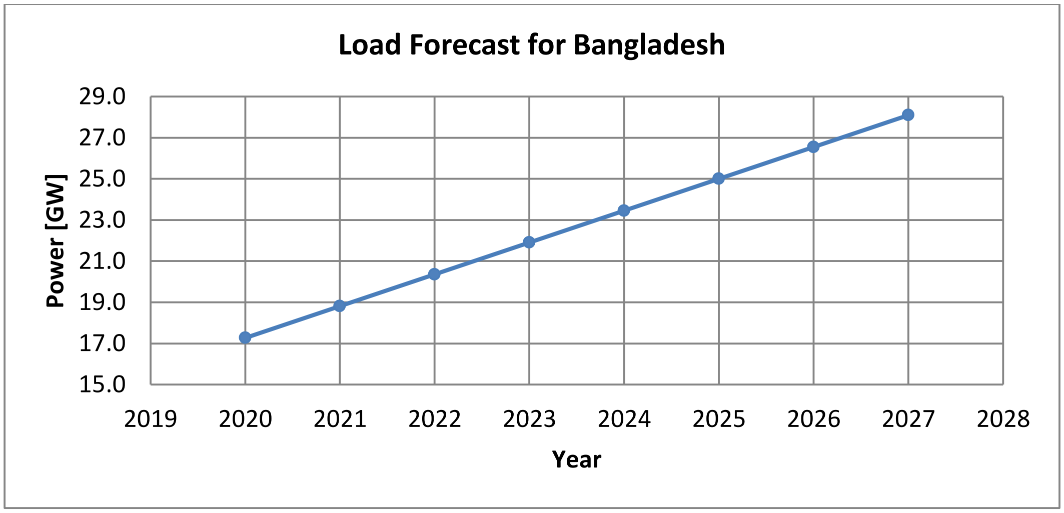


Figure 10-1: Load forecast for Bangladesh

The daily load curves of Bangladesh for all seasons are collected. Figure 10-2 shows a typical summer daily load curve of Bangladesh (in 2014) which Power Grid Company of Bangladesh Ltd publishes on its official website [1].

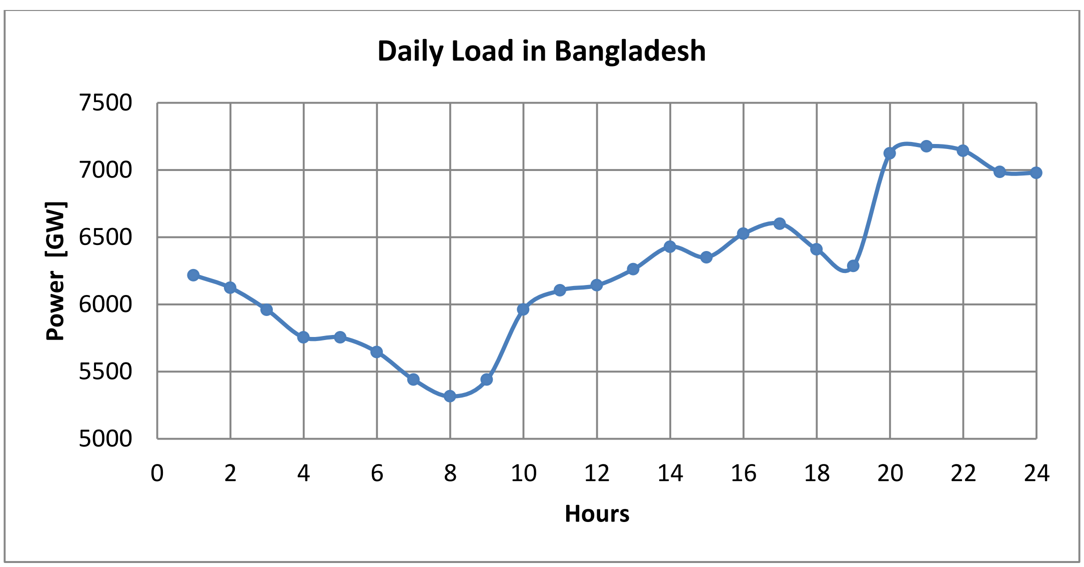


Figure 10-2: Summer daily load of Bangladesh

10.1.2 Generation

The only PSS/E case available for Bangladesh within the study period is for the year 2022. Discussions with authorities of Power Grid Company of Bangladesh revealed that the following list of future generation shown in Table 10-1 may be planned for years beyond 2022.

Table 10-1: List of future generation that was not included PSS/E™ case of 2022.

Location	Capacity (MW)	Technology
Barapukuria	274	Coal
Rooppur	2510	Nuclear
Meghnaghat	750	Gas
Mongla	1884	Coal
Payra	1320	Coal
Anowara	990	Gas
Anowara (Gohera)	300	Coal
Anowara (Orion)	1200	Coal
Matarbari	1320	Coal
Moheskhall	3960	Coal

Figure 10-3 shows the generation mix of Bangladesh in 2022 and 2027.

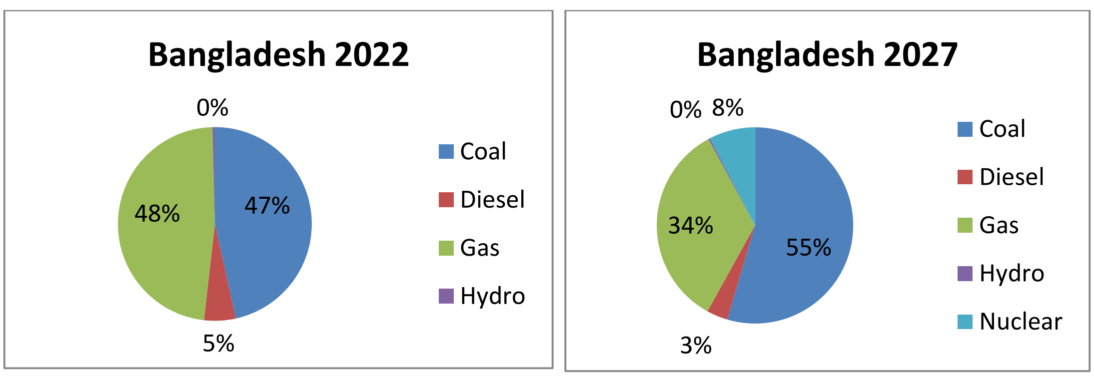


Figure 10-3: *Generation mix for case of Bangladesh for years 2022 and 2027.*

It can be observed that the generation mix shifts from being dominated by gas to have an equal mix of coal and gas. There is also the inclusion of nuclear power by the year 2027.

Table 10-2 shows the total generation capacity by technology in each year of study. The estimated total generation capacity for the year 2022 is 21,879.9 MW. The total estimated capacity for the year 2027 is 33,087.9 MW.

Table 10-2: Generation capacity by technology in Bangladesh

Year	Technology (MW)						
	Hydro	Coal	Gas	Nuclear	Diesel	Hydro	Total
2022	88	10179.6	10458.3	0	1154.0	88.0	**21879.9**
2027	88	18050.6	11285.34	2510.0	1154.0	88.0	**33087.9**

The availability factors for Bangladesh were not available; therefore, initially, the same availability values as the East India region were used. However, these factors may be modified in the economic analysis to maintain the power balance of each case.

10.1.3 Transmission

The transmission system for the economic model is defined using the PSS/E cases. Only the transmission system with voltage levels equal to or higher than 220 kV is considered to have thermal constraints, although the low voltage transmission lines and transformers are represented in the cases. Table 10-3 shows a summary of the transmission system for the 2022 PSS/E case in Bangladesh.

Table 10-3: Number of transmission branches by voltage level

Total no. of branches	No. of Branches (220kV and above)
1156	373

10.2 Power System of Bhutan

10.2.1 Load

The main source of information for Bhutan is the National Transmission Grid Master Plan (NTGMP) for Bhutan [3], provided by the Central Electricity Authority (CEA) of India, and [15]. Using this document and the PSS/E case of India that includes Bhutan, an estimation of the load for the period of study is carried out. This load forecast is shown in Figure 10-4.

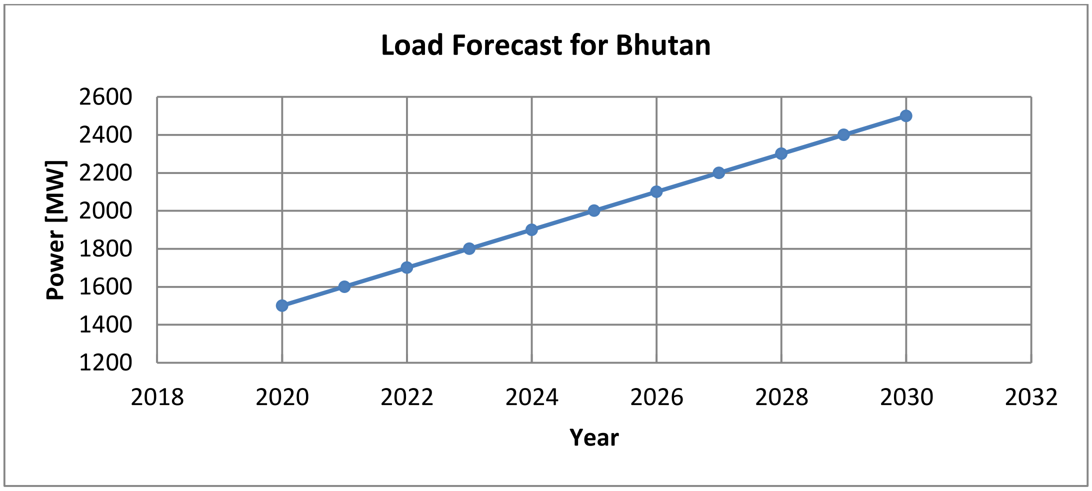


Figure 10-4: *Load forecast for Bhutan.*

Two daily load curves, one for summer and other for winter, are available for the study. They are represented in Figure 10-5 and Figure 10-6.

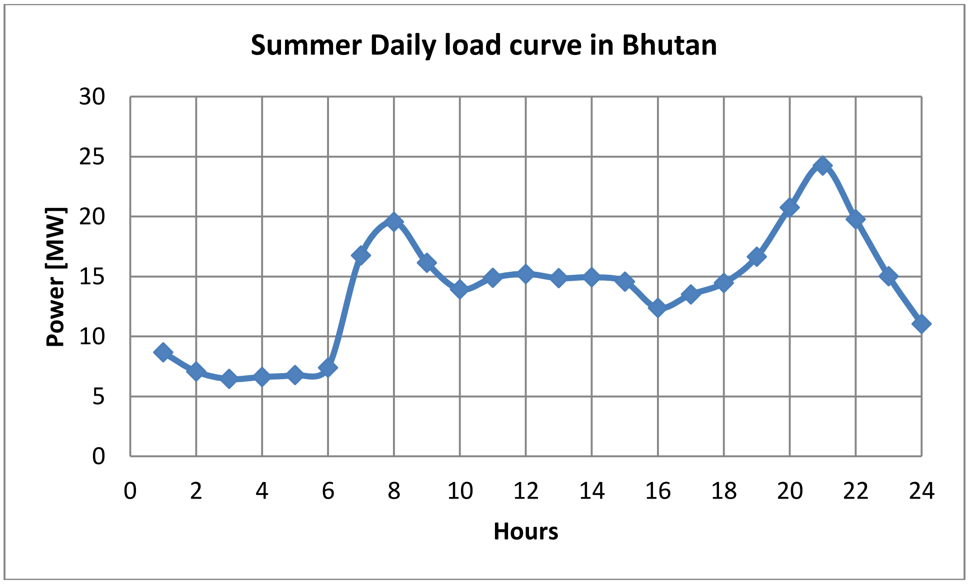


Figure 10-5: *Summer daily load curve for Bhutan*

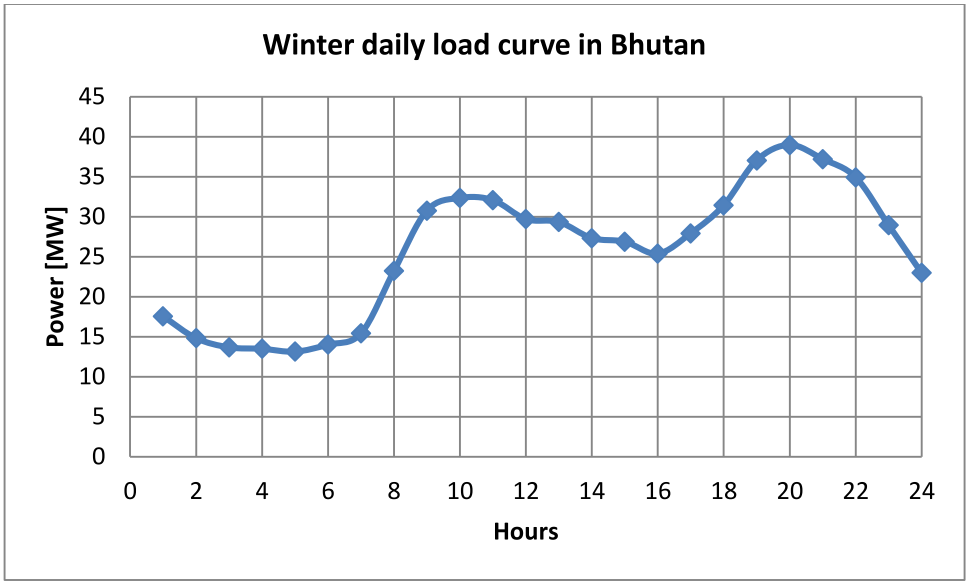


Figure 10-6: Winter daily load curve for Bhutan

10.2.2 Generation

The generation of Bhutan for the years of study is estimated using the 2027 Indian case which includes Bhutan network. The total capacity of Bhutan in this case is 6,582 MW. Banakha (180 MW), Wangchu (570 MW), Chankarchu (770 MW) generators are assumed to come in the period of 2022-2027 to obtain 2022 generation. As it can be seen in Figure 10-7, all generation of Bhutan is hydro power.

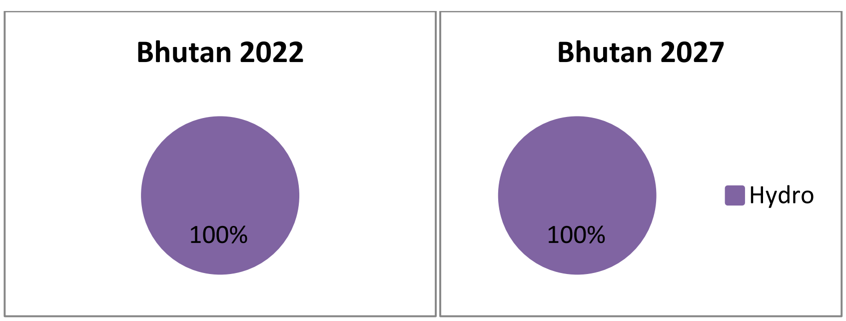


Figure 10-7: Generation mix for cases 2022 and 2027 of Bhutan

Table 10-4 shows the generation capacity of Bhutan in 2022 and 2027.

Table 10-4: Generation capacity by technology in Bhutan

Year	Technology (MW)						
	Hydro	Coal	Hydro	Nuclear	Hydro	Others	Hydro
2022	5162	0	0	0	0	0	**5162**
2027	6582	0	0	0	0	0	**6582**

No availability factors were collected for Bhutan. Therefore, the factors corresponding to India North-East region are used.

10.2.3 Transmission

The transmission system is modelled using the same PSS/E case used for estimating the generation. The transmission system of Bhutan is represented by 57 branches from voltage levels that go from 33 kV to 400 kV. The 220 kV is represented by 18 power lines. The 400 kV level is represented by 19 branches.

10.3 Power System of India

10.3.1 Load

The load data are compiled based on the load forecast obtained through discussions with CEA staff, PSS/E cases and the documents [4], [12]. The total estimated load forecast is depicted in Figure 10-8.

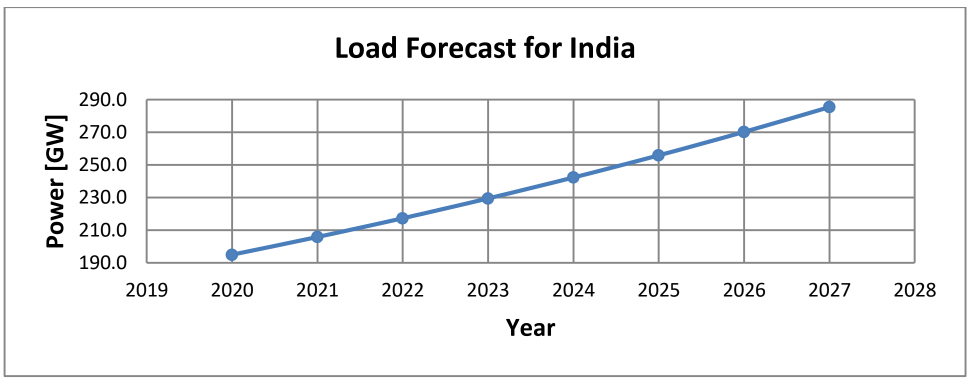


Figure 10-8: Total load forecast for India

The graphs from Figure 10-9 to Figure 10-13 show the load forecast for each of the five regions in India.

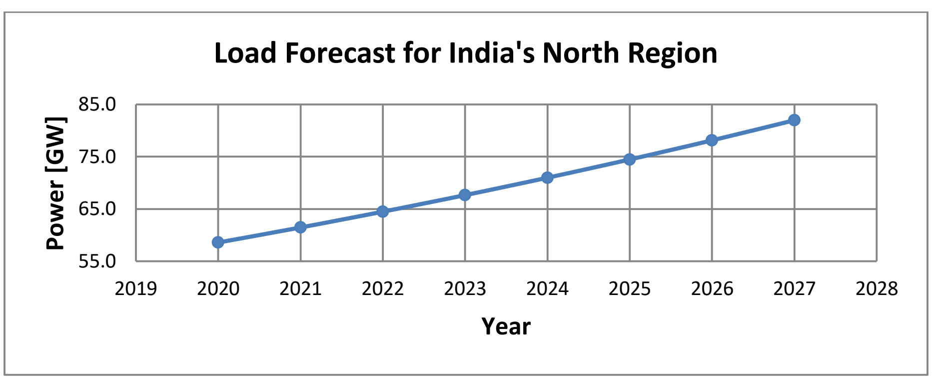


Figure 10-9: Load forecast in the North region

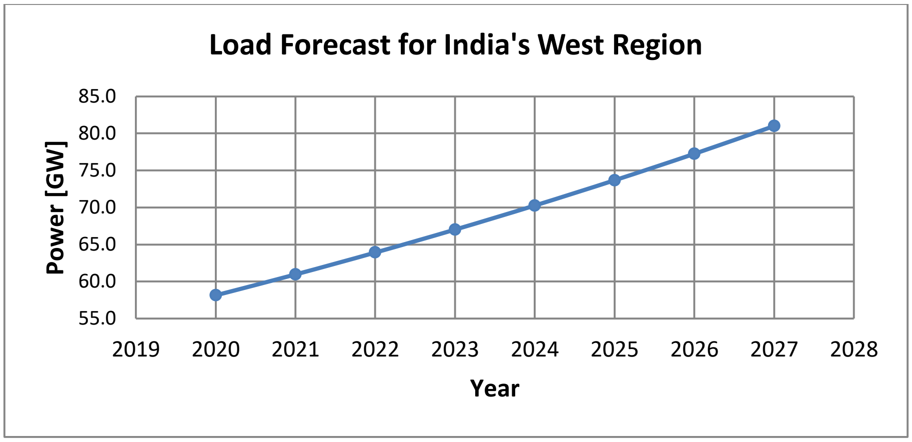


Figure 10-10: *Load forecast in the West region*

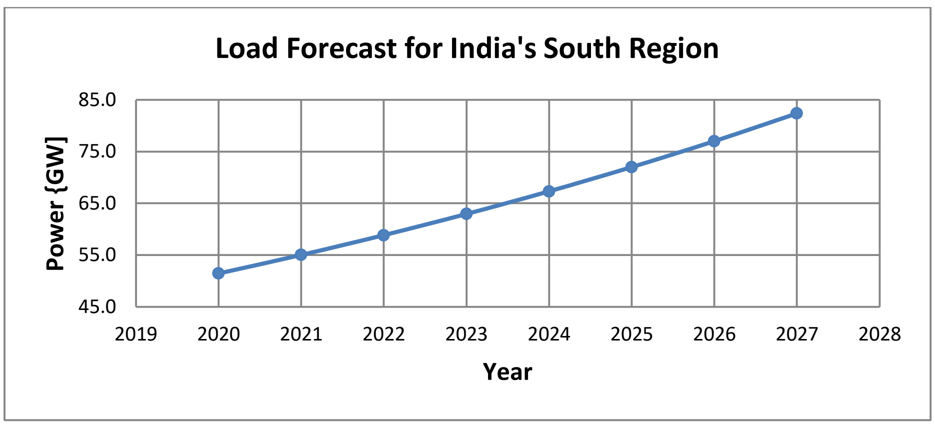


Figure 10-11: *Load forecast in the South region*

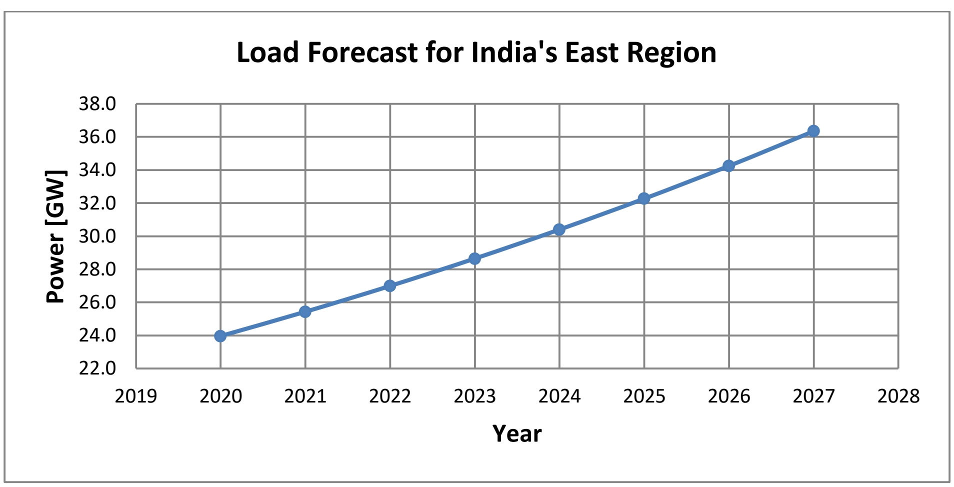


Figure 10-12: *Load forecast in the East region*

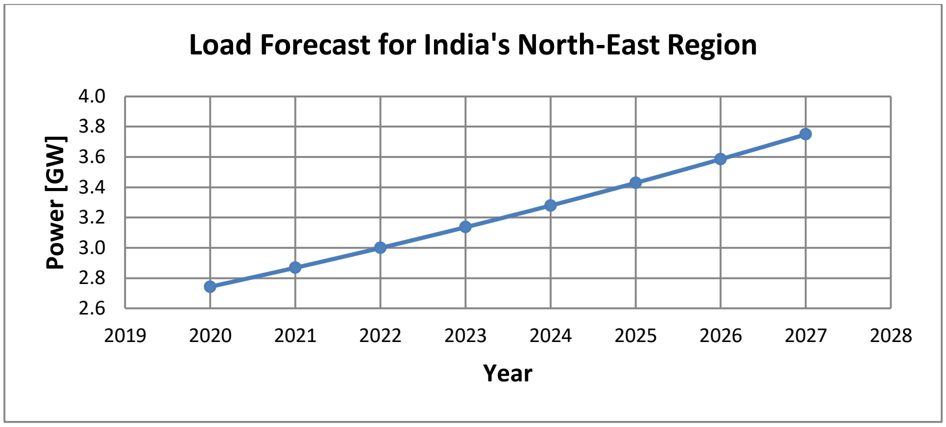


Figure 10-13: *Load forecast in the North-East region*

Load curves of each region of India for all four season are available. Figure 10-14 shows the summer daily load curves of India by region.

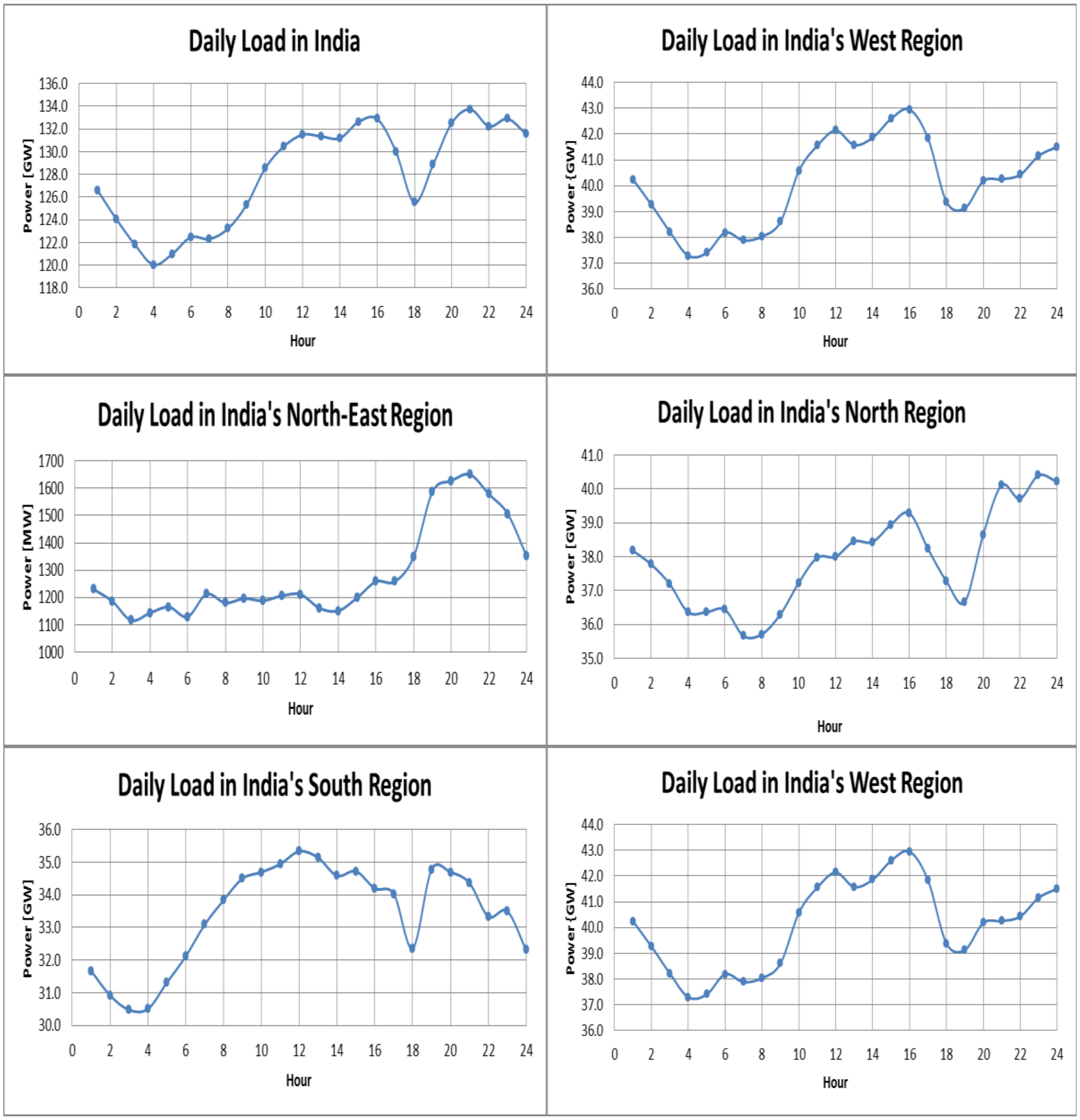


Figure 10-14: *Summer daily load curves in India*

10.3.2 Generation

10.3.2.1 Generation Capacity

The only PSS/E case available for India within the study period is for year 2027. Discussions with experts from CEA assisted in identifying a group of generators present in the 2027 case and not be commissioned before 2022. Moreover, the technology of most generators in the PSS/E cases was identified. The total generation in India is 375 GW in 2022 case and 440 GW in 2027 case. Region-wise breakdown of the generation capacity is shown in Table 10-5.

Table 10-5: Generation capacity in India by region and year

Region	Capacity 2022 (GW)	Capacity 2027 (GW)
East	59.0	77.8
North	81.3	97.8
North East	14.9	20.7
South	95.6	118.2
West	125.1	133.3
Total	**375.2**	**447.8**

10.3.2.2 Generation Mix

The generation mix in India for both years 2022 and 2027 is shown in Figure 10-15.

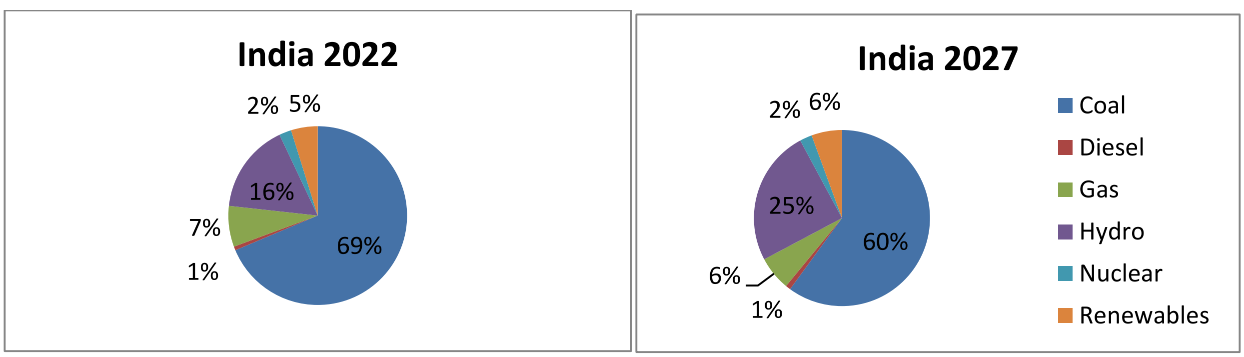


Figure 10-15: Total generation mix for 2022 and 2027 India cases

It can be observed that the India power generation is dominated by the coal based power in both study years. It is also observed that Hydro power generation and renewables are expected to be developed more in the study years.

The pie charts given in Figure 10-16 to Figure 10-20 show the technology mix of each region of India.

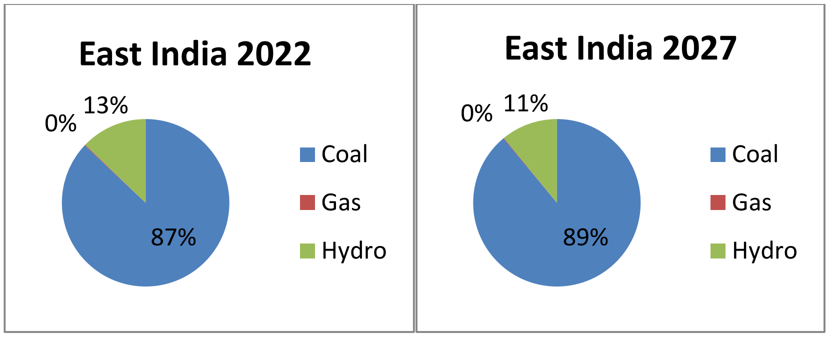


Figure 10-16: Generation mix for 2022 and 2027 in East India.

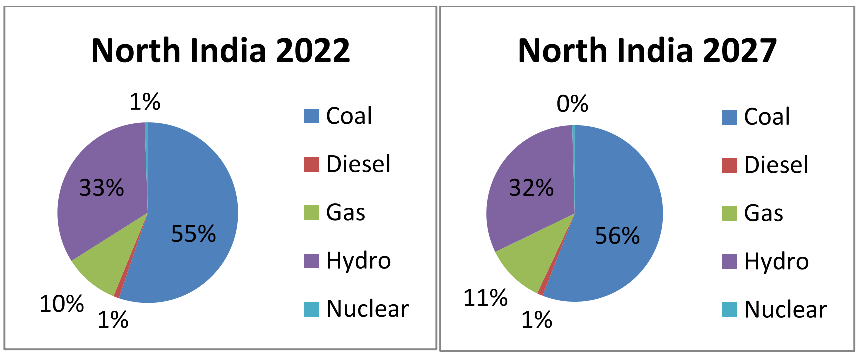


Figure 10-17: Generation mix for 2022 and 2027 in North India

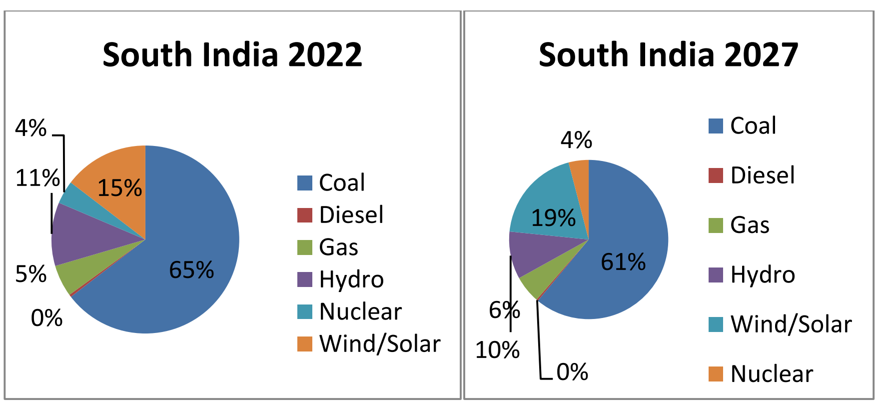


Figure 10-18: Generation mix for 2022 and 2027 in South India

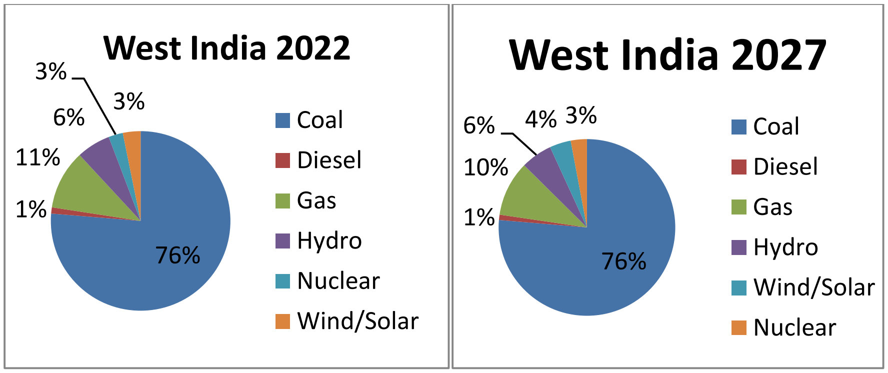


Figure 10-19: Generation mix for 2022 and 2027 in West India

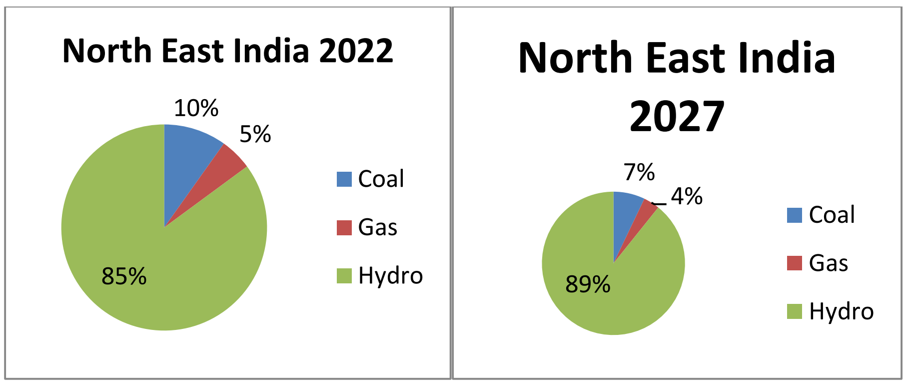


Figure 10-20: Generation mix for 2022 and 2027 in North-East India

Table 10-6 and Table 10-7 show the capacity of generation in 2022 and 2027.

Table 10-6: Generation capacity for 2022 India

Region	Technology (MW)						
	Hydro	Gas	Diesel	Coal	Renewables	Nuclear	Total
East	7461.2	90.0	0.0	50687.0	0.0	0.0	**58238.2**
North	27175.7	7999.1	826.7	44863.0	0.0	440.0	**81304.4**
South	10459.5	5230.7	404.0	61739.0	13970.0	3820.0	**95623.2**
West	7645.5	13359.8	1399.0	95451.8	3991.8	3240.0	**125087.9**
Northeast	12746.5	758.0	0.0	1476.0	0.0	0.0	**14980.5**
India	**65488.3**	**27437.6**	**2629.7**	**254216.8**	**17961.8**	**7500.0**	**375234.1**

Table 10-7: Generation capacity for 2027 India

Region	Technology (MW)						
	Hydro	Gas	Hydro	Coal	Hydro	Nuclear	Hydro
East	8474.2	90.0	0.0	69197.0	0.0	0.0	**77761.2**
North	31034.7	10599.1	1036.7	54703.0	0.0	440.0	**97813.4**
South	11409.5	6580.7	404.0	72119.0	22820.0	4820.0	**118153.2**
West	7645.5	13459.8	1299.0	101777.8	5191.8	3940.0	**133313.9**
Northeast	18505.7	758.0	0.0	1476.0	0.0	0.0	**20739.7**
India	**77069.6**	**31487.6**	**2739.7**	**299272.8**	**28011.8**	**9200.0**	**447781.4**

Coal-based power accounts for the majority of the generation capacity in Indian regions except the North-East region, which is dominated by hydro generation.

10.3.2.3 Generation Availability

The availability of generation is obtained for all seasons of India from the Perspective Transmission Plan for Twenty years (2014-2034) [12]. The availability factors for the summer season categorized by generation technology are shown in Table 10-8.

Table 10-8: Seasonal availability factors in India (summer)

Region	Hydro	Gas	Diesel	Coal	Renewables
East	40	0	0	73	10
North	70	23	23	80	10
South	50	41	41	80	10
West	30	14	14	80	5
Northeast	70	5	5	20	0

*Although availability factors have been retrieved, these factors seem to be similar to plant factors as they are really low for high cost generators (e.g. gas, diesel based power plants).

10.3.3 Transmission

The transmission system of 2022 and 2027 are derived transmission system based in the 2027 PSS/E™ case and references [22]. Major transmission upgrades planned for the 2022-2027 period were identified and removed from the 2022 India case. Table 10-9 and Table 10-10 show the number of branches for each region and voltage level in the cases. Only the branches with voltage levels equal or above 400 kV are used to apply thermal constraints in the optimization process (except for North-east where the limit is 220 kV).

Table 10-9: Number of branches in the transmission system of India for the years 2022

AREA/ Voltage	V=765 kV	V =400 kV	V=220 kV	V<220kV	Total
NORTH	122	772	1903	372	3169

NRTHEAST	0	82	104	547	733
WEST	159	618	1279	298	2354
EAST	45	428	619	344	1436
SOUTH	60	508	925	51	1544
Total India	386	2408	4830	1612	9236

Table 10-10: Number of branches in the transmission system of India for the years 2027

AREA/ Voltage	V=765 kV	V =400 kV	V=220 kV	V<220kV	Total
NORTH	124	776	1903	372	3175
NRTHEAST	0	82	104	547	733
WEST	166	650	1279	298	2393
EAST	51	428	619	344	1442
SOUTH	60	508	925	51	1544
Total India	401	2444	4830	1612	9287

As it can been seen the transmission capability between East and South has a significant increment.

10.4 Power System of Nepal

10.4.1 Load

The load forecast data were collected from the most recent annual reports of the Nepal Electricity Authority [5], [6]. The estimations have been compared with the load data used in the “Power System Study Report on India-Nepal: 2020-2021” [7]. Figure 10-21 show the estimated load forecast.

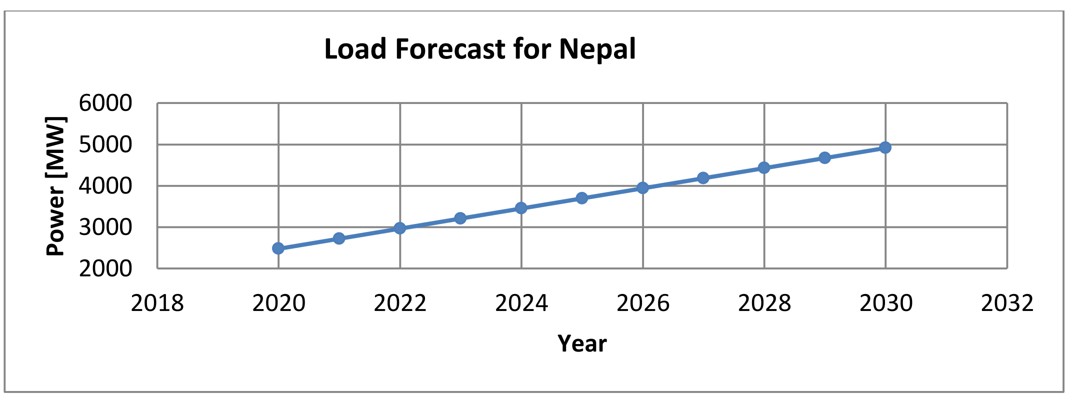


Figure 10-21: Load forecast for Nepal.

Daily load curves for Nepal are collected for all seasons. Figure 10-22 shows the daily curve used in the study to represent a typical day of summer in Nepal.

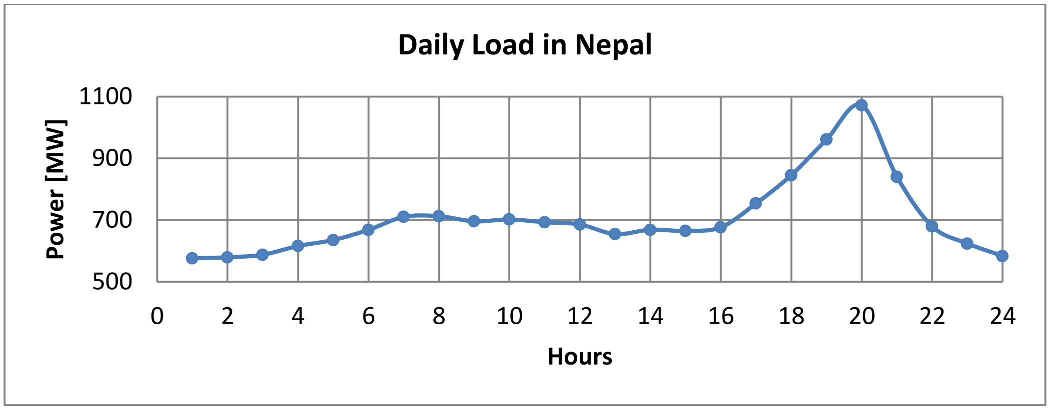


Figure 10-22: Summer daily load of Nepal

10.4.2Generation

Two PSS/E™ cases of 2022 and 2027 have been used to model the generation in Nepal. The total capacity in Nepal in for the case 2022 is 5164.79 MW. The 2027 case shows a total maximum capacity of 21600.28 MW. As it can be seem in Figure 10-23 all the generation in Nepal is hydro.

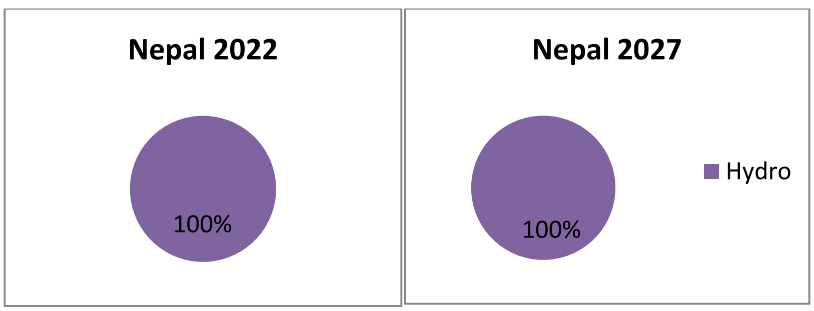


Figure 10-23: Generation mix for cases 2022 and 2027 of Nepal.

The availability factors for each season and generation technology for Nepal are assumed to be similar to that of the India North region. Table 10-11 shows the generation capacity of Nepal in 2022 and 2027.

Table 10-11: Generation capacity in Nepal for each year of study

Year	Technology (MW)						
	Hydro	Coal	Gas	Nuclear	Diesel	Others	Total
2022	5153.5	0	0	0	0	0	**5153.5**
2027	20299.0	0	0	0	0	0	**20299.0**

10.4.3 Transmission

The transmission system for the scenario 2027 in Nepal has 749 branches. Only the branches with a voltage level equal or higher than 220 kV were applied with thermal constraints in the optimization model. A summary of these values can be found in Table 10-12.

Table 10-12: Number of transmission branches by voltage level in Nepal.

Year	Total number of branches	Branches operating to 220kV and above
2022	688	109
2027	749	157

10.5 Power System of Sri Lanka

10.5.1 Load

The load forecast in Sri Lanka shown in Figure 10-24 and it is based on reference [24].

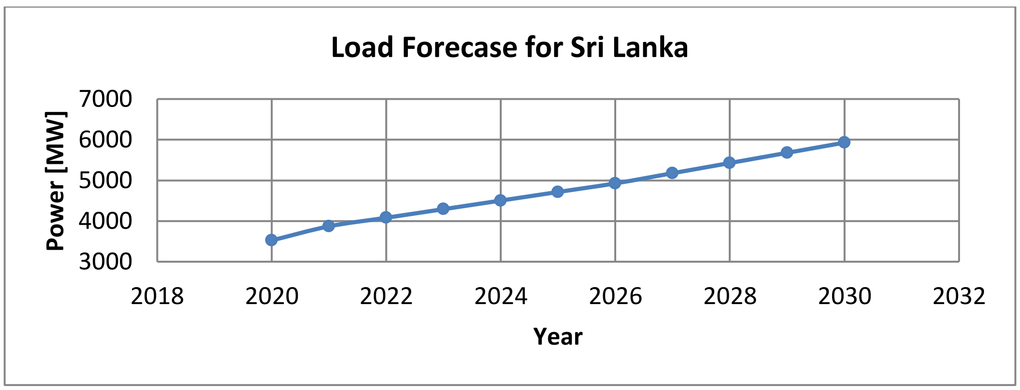


Figure 10-24: Load forecast for Sri Lanka.

The daily load curve given in [24] is used for Sri Lanka for all seasons. The available daily load curve is shown in Figure 10-25.

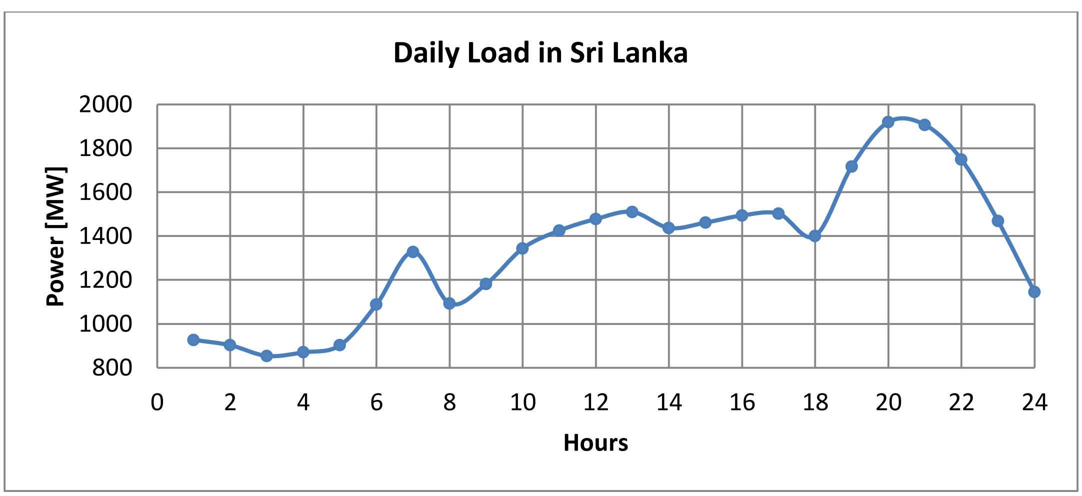


Figure 10-25: Summer daily load of Sri Lanka.

10.5.2 Generation

2021 and 2026 PSS/E™ cases are used to obtain 2022 and 2027 generation of Sri Lanka. The scenario 2022 has a total maximum capacity of 5932 MW. The 2027 case has a total maximum capacity of 6952.3 MW. Figure 10-26 shows the mix of generation for the two considered scenarios.

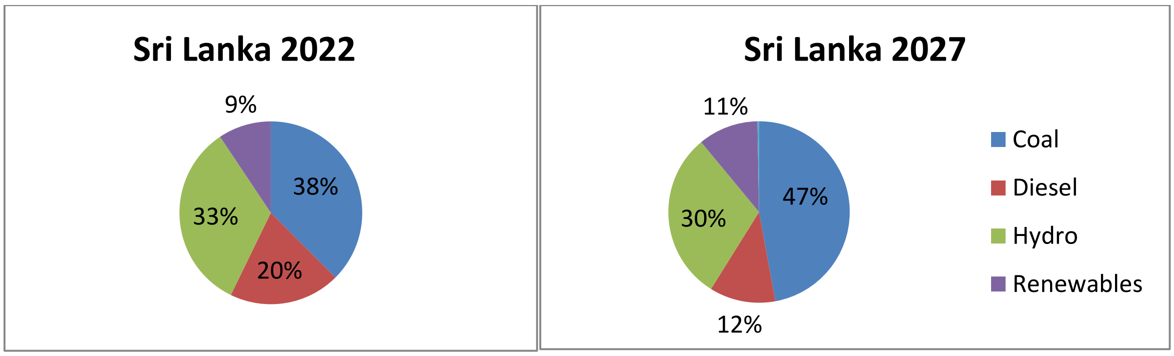


Figure 10-26: Generation mix for cases 2022 and 2027 of Sri Lanka.

It can be seen that coal based power is the largest contributor to the generation in 2022, this increases further in 2027. A major difference seen in 2027 is the reduction of the reliance on diesel and gas.

Table 10-13 shows the generation capacity for each technology.

Table 10-13: Generation capacity in Sri Lanka for each year of study.

Year	Technology (MW)				
	Hydro	Coal	Diesel	Renewable	Total
2022	1982	2225	1169	556	5932
2027	2092.8	3276	818	745.5	6952.3

10.5.3 Transmission

The voltage levels selected to include thermal constraints in the optimization model is 132 kV and above. The transmission system in Sri Lanka for the year 2022 is modelled by 418 branches and the 2027 scenario is modelled with 455 branches.

10.6 Power System of Pakistan

10.6.1 Load

Most of the information of Pakistan has been collected from reference [25] and the PSS/E™ cases. The low load growth scenario in reference [25] is deemed optimistic and the load forecast is shifted back three years to obtain a reasonable load increment for the study period. Figure 10-27 shows estimated load forecast based on these sources.

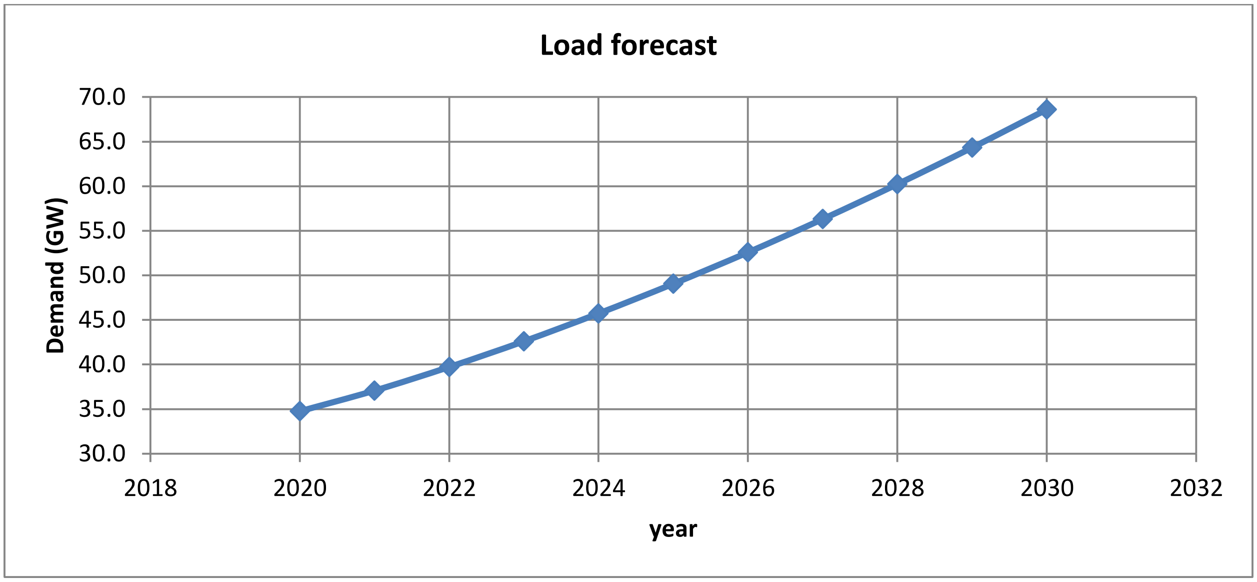


Figure 10-27: *Load forecast for Pakistan*

Two daily load curves are collected to represent Pakistan load. Figure 10-28 shows the summer daily load curve of Pakistan.

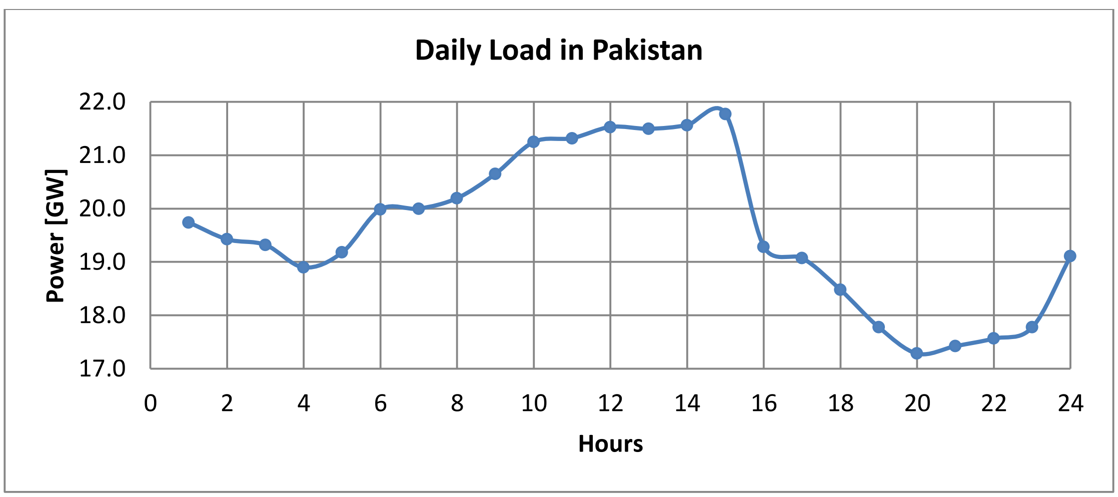
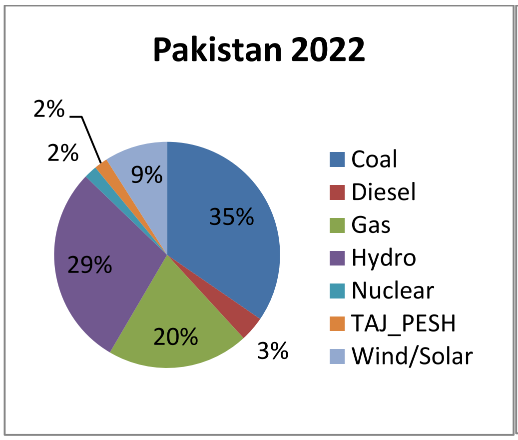


Figure 10-28: *Summer daily load of Pakistan*

10.6.2 Generation

The total maximum capacity for 2022 case is 52.0 GW and the total maximum capacity for the year 2027 is 82.7 GW. A major increase in generation resources is seen by 2027. The mix of technology is shown in Figure 10-29: Generation mix of Pakistan. The amount of power for each technology and year is shown in Table 10-14.

Some mapping between both cases could be done if they share bus names, but this is not the case in many generation buses.



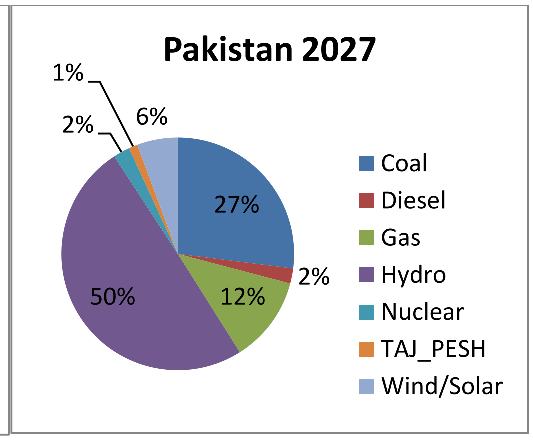


Figure 10-29: Generation mix of Pakistan

Table 10-14 indicates that there will be a significant increase in hydro generation in 2027 compared to 2022. There is also a noticeable increase in coal based power generation.

Table 10-14: Generation capacity in Pakistan for each year of study

	Technology (MW)							
Year	Hydro	Coal	Gas	Nuclear	Diesel	Renewable	Import	Total
2022	14938.0	17979.0	10544.0	970.0	1860.0	4690.0	1000.0	**51981.0**
2027	41178.0	22346.0	9881.0	1920.0	1735.0	4690.0	1000.0	**82750.0**

Table 10-15 gives the list of large plants planned for the period 2022-2027.

Table 10-15: Large power plants planned for the 2022-2027 period for Pakistan

Project Name	Type	Units	Total Capacity (MW)	Commissioning Year (model)
Bunji 1	Hydro	7	1785	2023-24
Bunji 2	Hydro	7	1785	2024-25
Bunji 3	Hydro	7	1785	2025-26
Dudhnial	Hydro	1	792	2028-29
Karachi	Nuclear	1	940	2026-27
Karachi	Nuclear	1	940	2027-28
Qadirabad	Nuclear	1	940	2023-24
Dasu	Hydro	8	4280	2026-27

Project Name	Type	Units	Total Capacity (MW)	Commissioning Year (model)
Diamer Basha 1	Hydro	6	2226	2023-24
Diamer Basha 2	Hydro	6	2226	2025-26
Thar # 5	Coal	4	2268	2023-24
Thar # 6	Coal	1	567	2024-25
Thar # 7	Coal	4	2268	2026-27

10.6.3 Transmission

The summary of transmission system of Pakistan for the year 2022 and year 2030 is shown in Table 10-16. The voltage levels selected to include thermal constraints in the optimization model is 400 kV and above.

Table 10-16: Number of transmission branches by voltage level in Pakistan

Year	**Total number of branches**	**Branches operating to 400kV and above**
2021	1418	192
2025	1665	361

10.7 Power System of Afghanistan

10.7.1 Load

The load forecast for Afghanistan is shown in Figure 10-30. It is estimated based on the PSS/E cases that have been provided.

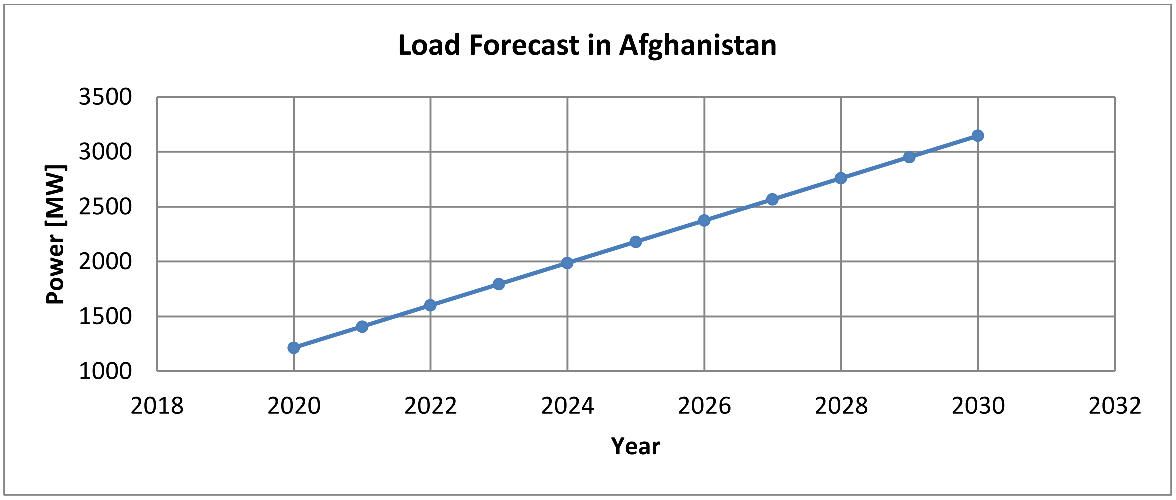


Figure 10-30: *Load forecast for Afghanistan*

The daily load curve for Afghanistan is shown in Figure 10-31.

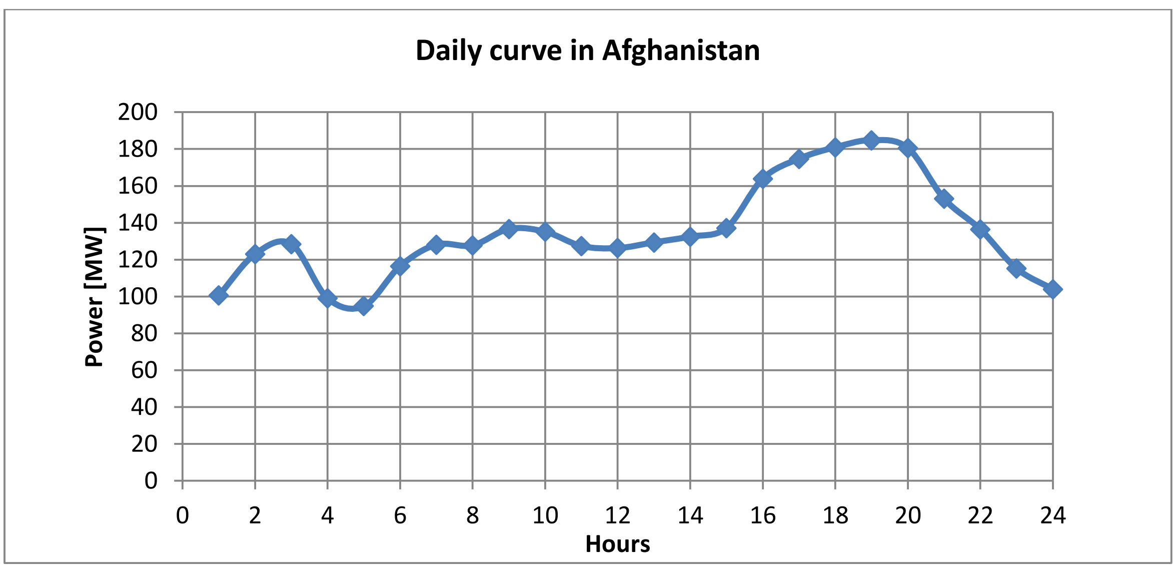


Figure 10-31: *Daily load curve in Afghanistan*

10.7.2 Generation

There is no information to map the generation technology in Afghanistan. The total capacity for the 2022 scenario is 2,496 MW. The total maximum capacity for the 2027 scenario is 8,477.9 MW.

The reference [26] shows a description of the actual network in Afghanistan and the future generation plans. Figure 10-32 and Table 10-17 give the generation mix of Afghanistan for years 2022 and 2027.

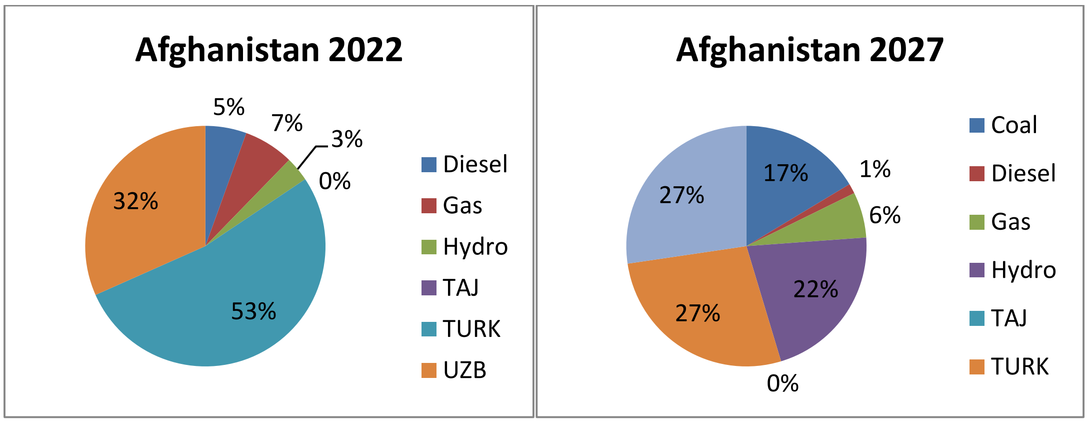


Figure 10-32: Generation mix of Afghanistan

Table 10-17: Generation capacity in Afghanistan for each year of study

Year	Hydro (MW)	Coal (MW)	Gas (MW)	Nuclear (MW)	Diesel (MW)	Renewable (MW)	Import (MW)	Total (MW)
2022	63.0	0.0	128.0	0.0	105.0	0.0	1600.0	1896.0
2027	1572.5	1200.0	448.0	0.0	97.7	0.0	4000.0	7318.2

10.7.3 Transmission

A summary of the Afghanistan transmission system is found in Table 10-18. Only the branches that operate with voltage higher than 220 kV are used to impose thermal constraints in the optimization model.

Table 10-18: Number of transmission branches by voltage level in Afghanistan

Year	Total number of branches	Branches operating to 220kV and above
2022	499	251
2027	506	254

11 Appendix B - Cross-border Transmission Links

11.1 Existing and Planned cross-border transmission links

11.1.1India-Bhutan

- Alipurduar (India) – Tala (Bhutan). The link consists of 2 circuits operating to 400 kV with a total transfer capability of 1100 MVA. These links are not in service.
- Siliguri (India) – Tala (Bhutan). The link consists of 2 circuits operating to 400 kV with a total transfer capability of 1100 MVA.
- Siliguri (India) – Wangchu (Bhutan). The link consists of 1 circuit operating to 400 kV with a total transfer capability of 550 MVA.
- Siliguri (India) – Malebase (Bhutan). The link consists of 1 circuit operating to 400 kV with a total transfer capability of 550 MVA.
- Alipurduar (India) – Punatsanc (Bhutan). The link consists of 4 circuits operating to 400 kV with a total transfer capability of 2588 MVA.
- Alipurduar (India) – Jimeling (Bhutan). The link consists of 2 circuits operating to 400 kV with a total transfer capability of 1300 MVA.

11.1.2 India – Bangladesh

- Baharampur (India) – Bheramara (Bangladesh). It is an HVDC cross-border transmission link with a total transfer capability of 1000 MVA.

11.1.3 India – Nepal

- Muzaffarpur (India) – Dhalkebar (Nepal). The cross-border transmission link consists of 1 circuits operating to 400 kV with a total transfer capability of 1000 MVA.

11.1.4 India – Sri Lanka

There is no current cross-border transmission link between these two countries.

11.1.5 India – Pakistan

There is no current cross-border transmission link between these two countries.

11.1.6 India – Afghanistan

There is no current cross-border transmission link between these two countries.

11.2 Potential Cross-border transmission links

The following sub-section provides a brief account of each possible cross-border transmission link. An initial list of future cross-border transmission link candidates is prepared using a number of reports (by the involved agents) that suggested possible locations and technologies. The initial list of candidate projects can be found in Appendix 14

Subsequently, the list of candidate projects has been modified and shortlisted to eight projects. The criteria for filtering the potential projects are as follows:

- Existence of generation PDA that justify the construction;
- Information received from power system authorities of the respective countries.

Moreover, transmission lines that are going to be commissioned before 2017 are not considered in the final list, because those projects already have a financial closure.

The list of potential projects is as follow:

Id codification: I=India, BA=Bangladesh, BU=Bhutan, N=Nepal, AF=Afganistan, PA=Pakistan.

1. IBA: Rangia/Rotwa (India) - Barapukuria (Bangladesh) – Gurudaspur (India)
2. IN1: Gorakhpur (India) - Marsyangdi (Nepal)
3. IN2: Bareilly (India) - Upper Karnali (Nepal)
4. IBU: Rangia/Rowta (India) - Yangbari (Bhutan)
5. ISL: Madurai (India) - New Anuradhapura (Sri Lanka)
6. IPA: Amritsar (India) - Lahore (Pakistan)
7. AFPA: Arghandi (Afganistan) – Jalalabad (Afganistan) – Peshawar (Pakistan)
8. PATJ: Rogun (Tajikistan) – Peshawar (Pakistan)

Figure 11-1 depicts the previous list of transmission links.

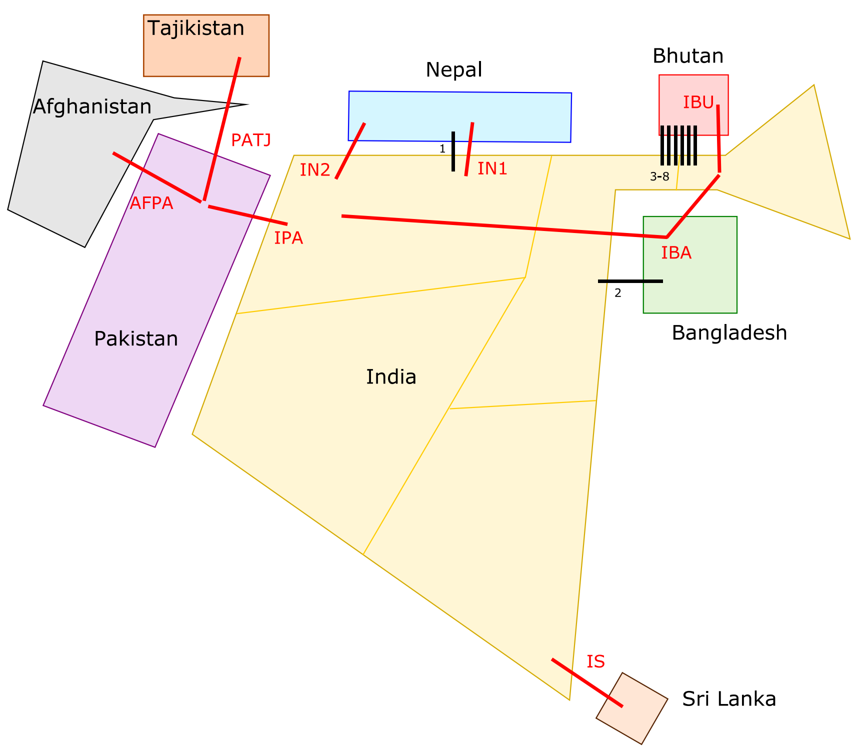


Figure 11-1: Schematic map of the proposed cross-border transmission links.

The following section provides a description of the shortlisted candidate projects, including the possible locations of ‘sending’ and ‘receiving’ line ends, technology, voltage level, associated generators and loads, cost estimation, and remarks.

11.2.1 India-Bhutan

A PTA was signed in 2006 with the objectives of the construction of a minimum of 5000 MW of hydro power by 2020, and the building of the necessary transmission capacity to export that power to India after meeting the Bhutan demand. In 2006, the Bhutan government and Power Trading Corporation (PTC) of India signed a PPA to export 5620 GWh per year for the next 35 years [16]. It is expected that new PDAs will be signed to develop the already identified hydro power in Bhutan, which will be exported mainly to India.

Acronym: IBU

Receiving end: Rangia/Rowta (India)

Sending end: Yangbari (Bhutan)

Technology: AC double circuit

Voltage Level: 400kV

Rating: 1000 MW

Associated Generation: The transmission link is anticipated to collect initial power outputs from future hydro power stations in the East part of Bhutan scheduled for commissioning between 2017 and 2020, Kuri-Gongri (1800 MW), Kholongchhu (650 MW), Chamkharchhu-I (970 MW), Rotpashong (918 MW), Gamri (102 MW) [14].

Associated Loads: The 2030 master plan of Bhutan [3] shows that the pooling substations of Yangbari and Rangia/Rowta will have HVDC transmission links for further power collection. Those transmission systems will transfer power to the North region of India, but there are no specifics of the load locations.

Remarks: Jigmeling in the center of Bhutan and Yangbari in the East are the pooling substations to collect the hydro power from the Manas river system (Mangde Chhu, Chamkhar, Kuri Chhu, and Dangme Chhu).

11.2.2 India - Bangladesh

The most recent PDA was signed in April 2014 to build a 6000MW multi-terminal HVDC system that will allow transmitting power from the North-East region to the North region of India through Bangladesh. The line route is along the west side of the Padma River in the North of Bangladesh, and provides an alternative to the already congested chicken-neck area in India. An intermediate converter station in Barapukuria will allow supplying between 500-1000 MW to support power demand in Bangladesh.

Acronym: IBA

Sending end: Rangia/Rotwa (India)

Intermediate point: Barapukuria (Bangladesh) (The receiving end will be built in some load center in India; location not confirmed)

Technology: Multi-terminal HVDC system

Voltage Level: ±800 kV

Rating: 6000 MW- a 500 MW/1000 MW HVDC terminal in Barapukuria will be used for drawing power to Bangladesh

Associated Generation: Several generation plants are planned to be built at the Tawang and Kameng river basins (Arunachal Pradesh, India). Kameng (4x150 = 600 MW) has been commissioned, and Subansiri (8x250= 2000 MW, expected commissioning date - 2016 and full capacity by 2018) has a PDA [20].

Associated Loads: Load centers are in the North region of India as well as Bangladesh. Preliminary locations that have been reported in India are Muzaphranagar, Meerut or Gnoida. The power converter in Barakupuria is expected to deliver power to the Dhaka area.

11.2.3 India - Nepal

In September 2014, a PDA was signed between power generation developers and the government of Nepal to build a 900 MW run-of-river hydro power plant in Upper Karnali. It expected that this power will be mainly exported to India. Another PDA has been signed in November 2014 between the Nepali government and SJVN Limited to build Arun-III, a 900 MW hydro power plant. The power generation of this project will be transmitted using Dhalkebar-Muzaffarpur line. Detailed Project Reports (DPR) are being prepared for several projects, and PDAs are expected to be signed in the future.

Acronym: IN1

Sending end: Marsyangdi (Nepal)

Receiving end: Gorakhpur (India)

Technology: AC double circuit

Voltage Level: 400kV

Rating: Not confirmed

Associated Generation: This cross-border transmission link is expected to transfer power from the future 600 MW Upper Marsyangdi-2 hydropower project located on the Marsyangdi River in the Manang and Lamjung districts. It is expected to be commissioned in 2021.

Associated Loads: Gorakhpur is a densely populated city, and its economy is based on services. A portion of the power is likely to be transferred to other industrialized areas.

Acronym: IN2

Sending end: Upper Karnali (Nepal)

Receiving end: Bareilly (India)

Technology: AC double circuit

Voltage Level: 400kV

Rating: 1000 MW

Associated Generation: This cross-border transmission link is expected to transfer power from the future 900 MW run-of-river Upper Karnali hydro project. Financial closure is expected in September 2016, and commercial operation by September 2021.

Associated Loads: The pooling substation is Bareilly, which is well connected with other big consumer centers of the Indian North region.

11.2.4 India – Sri Lanka

Both governments signed a MoU in June 2010 to conduct a feasibility study for the cross-border transmission link of the two national power grids. Power Grid Corporation of India Ltd. and Ceylon Electricity Board completed the technical study in 2012. The proposed project is a two stage 400KV 1000MW HVDC Bipole cross-border transmission link, which has 120 km of undersea cable. The discussions are in progress on how to modify the project to achieve a more favorable economic scenario.

Acronym: ISL

Sending/Receiving end: Madurai (India)

Receiving/Sending end: New Anuradhapura (Sri Lanka)

Technology: HVDC bipole

Voltage Level: 400kV

First stage rating: 500 MW

Associated in South India/Sri Lanka: NTPC (National Thermal Power Corporation) of India has signed an agreement with the Ceylon Electricity Board to build a 500 MW coal based power plant in Sri Lanka. There is also significant potential for wind power in Sri Lanka [14].

Associated Loads: The cross-border transmission link can be used for covering peak demand in Sri Lanka or to supply the load in South India region during off-peak in Sri Lanka, as generation in the island is developed.

Cost Estimation: The total cost of construction is estimated at $700 million. The estimate is divided into two stages. The first stage of 500 MW would consist of two 250 MW converters in series at each end with the sea cables and metallic return at an estimated cost of $545 million. The second stage would add a further 500 MW of transfer capacity at an estimated cost of $155 million.

Remarks: The MoU was signed in 2010, and a feasibility study was finished in 2012. The main challenge of the project is the route of the sea cable that extends for 120 km (Panaikulam (India) - Thirukketiswaram (Sri Lanka)), and its cost is a significant percentage of the total cost. There are discussions to improve the proposed option. The Ceylon Electricity Board has established economic viability at a project cost of $400 million USD. This limit could be reached by changing the route, and building one single 500 MW monopole converter in the first phase.

11.2.5 India - Pakistan

Discussions between both governments to exchange power have being carried out since 2012. In March 2014, a MoU was signed for the creation of a technical committee to study possible power exchange [14]. A 400 kV double-circuit line from Amritsar (India) to Lahore (Pakistan) with a back-to-back 500 MW HVDC station in Lahore is envisioned to avoid the synchronization of both grids. There is no a PDA or PTA signed for the project as of yet.

Acronym: IPA

Sending end: Amritsar (India)

Receiving end: Lahore (Pakistan)

Technology: AC Quad double circuit, and back-to-back HVDC converter at Lahore terminal.

Voltage Level: 400 kV

Rating: 1000 MW

Associated Generation: The sending end of the line is in the North region of India that has adequate access to generation and also expects to receive power from the future hydro power plants in Arunachal Pradesh (North-East region) and Bhutan.

Associated Loads: The 2015 peak demand in Pakistan was 5000 MW higher than the total generating capacity of the country. Any power capacity addition will help to mitigate the continuous power shortages.

References: The initial plan is to deliver 500 MW from India and use it on a load area isolated from Pakistan power system, although the Pakistan government would like to raise the rating to 1000 MW. The transmission system can be built in one year or one year and a half, but the converter stations will need about three years. In addition, both countries will need to strengthen their transmission systems that are connected to the terminal stations.

11.2.6 Afghanistan – Pakistan

Arghandi in Afghanistan is strongly connected to Pul-e-Chomri in North Afghanistan which is connected to Tajikistan, Uzbekistan and Turkmenistan. Arghandi is also well connected to Jalalabad in the East. Therefore, Arghandi provide a stiff 500 kV backbone for a cross-border transmission link with Pakistan at Peshwar with a back-to-back HVDC at the border, this backbone is part of the TUTAP arrangement envisaged by Fitchner to supply power to Pakistan. This connection would allow Afghanistan to draw power (around 300 MW) from the neighbouring countries. One possible scenario then is to transfer the full 1300 MW of CASA power to Pakistan without supplying to Afghanistan.

Acronym: AFPA

Sending end: Arghandi (Afghanistan)

Receiving end: Peshawar (Pakistan)

Technology: HVDC

Voltage Level: 500 kV

Rating: 1000-1300 MW

Associated Generation: Power will be imported from Uzbekistan, Turkmenistan and Tajikistan to be transferred to Afghanistan/Pakistan

Associated Loads: If affordable, this can service a small amount of the Afghanistan load (300 MW), otherwise will directly serve the load in Pakistan.

11.2.7 Pakistan-Tajikistan

This transmission link has the purpose of evacuating the surplus power from the hydro power plants in Tajikistan to South east of the continent through Pakistan.

Acronym: PATJ

Receiving end: Rogun (Tajikistan)

Sending end: Peshawar (Pakistan)

Technology: HVDC

Voltage Level: 500kV

Rating: 1000 MW

Associated Generation: There is potential to develop hydro power plants in the Vakhsh River. The Rogun hydro power plant has been designed to deliver 3.600 MW of electric power, but the commissioning day is unknown due to disputes for the hydro resources.

Associated Loads: The surplus of power can be delivered and consumed in Pakistan or evacuated to the North West part of India.

12 Appendix C - Description and Validation of the Optimization Program for Economic Evaluation of Power Systems

12.1 Description

The method to carry out these calculations can be divided in four main stages (problem definition, optimization, solver, and calculations), as depicted in Table 12-1.

The core of the program is the optimization block that this section describes in detail.
A transmission plan is evaluated from the economic point of view by minimizing the operating cost of the power system. The main idea is that the addition of new power lines modifies the local marginal prices in the buses where they are connected. Hence the optimal generation dispatch is also modified, which affects the overall operating cost of the system.

The first part of the analysis is to define scenarios. It is obvious that the power system evolves each year, due to the addition of generators, loads and transmission lines to the system. A base case scenario is selected for each year in which all the future generation, the peak demand for that year and the transmission links are defined. The optimization program will determine the optimum generation dispatch to minimize cost while meeting system steady state operating constraints (thermal).

The representation of the power system operation during a single year accounts for the seasonal variations of loads. Typical daily curves for each season are used to calculate the peak load of the base cases for each season. As an example, if four seasons (winter, summer, monsoon and post-monsoon) are defined, each year would have four seasonal base cases. Selected transmission lines that are interconnecting countries are the focus of the study. The addition of one or more transmission candidates will generate two sets of scenarios:

- A set with only the base topology
- A set with the addition of cross-border connections.

Inclusion of N-1 criteria: Due to the size of the network the application of N-1 criteria for every element is not computationally practical. Thus only a list of carefully selected power lines and generators are considered when optimizing the system. It is assumed that elements that are not tested against N-1 have an insignificant impact on the cross-border transmission links.

The optimization block will calculate the optimal cost of operation of the defined scenarios. The block operates in five stages corresponding to the modules listed in the Table 12-1 below. The models are written in AMPL which is an algebraic language specialized for formulation of optimization problems. The main module calls the *variables and parameters* module, the *read data* module and the *output* module sequentially. The *variables and parameters* module calls the *set up user options* module and then returns to the main module. Table 12-1 provides a brief description of each module.

Table 12-1: Program Modules and Descriptions

Module	Description
Main	This module controls the execution of the program. It calls other modules and the solver.
Definition variables and parameters	It establishes the variables which are to be solved, and the input parameters for the optimization module. ▪ Variables: Bus angles, Generation dispatch, Generation status, Power flow in the lines and HVDC transmission links ▪ Parameters: o Buses: Name, Number, Type. o Lines: From bus, To bus, Tap, Angle, Reactance, Rating, Security constraint flag. o Generation: Bus number, Maximum active power, Minimum active power, Ramping constant, Security constraint flag. o Load: Bus number, Active power for each period.
User options set up	It sets up the type of optimization problem to be solved using the environmental variables defined by the user. The options that the user can set up are: • Case path: The folder in which the case files are storage. • Out path: The folder where the program is going to save the output files with the results. • Unit commitment: Include unit commitment constraints • Multi period: If this option is enabled, the program calculates the optimal dispatch for each period. • Quadratic: If zero - the program uses only the linear coefficients to model the production cost function of each generator. • Number of columns in loads: Each column represents the load in one period. The program needs to know how many periods are represented in the input file (to read that file). • Number of periods: It is the total number of periods that are to be solved. • Inter-temporal ramping constant: This parameter is used to constrain the amount of power that can be changed for a particular generator between two consecutive periods. Example: if the ramping constant of a generator is 10 MW/minute and inter-temporal ramping constraint is 10 minutes that the generator can change ±100 MW from one period to the next. • Intercase ramping constant: this parameter is used to define how much power a generator can re-dispatch between the operating point of the base case and the case with a contingency.
Model	The mathematical formulation of the optimization problem. It is composed of three elements: the objective function, the constraints and the problem. • Objective function: addition of all cost of operation functions. • Constraints: the inequalities that restrict the solution space. o Power balance: o Power line thermal limits: Applied to both AC and HVDC transmission links. o Maximum generating power: The dispatched active power should be less than the maximum rating of the generator. o Minimum generating power: The dispatched active power

Module	Description
	should be greater than the minimum power that the generator can dispatch. o Inter-temporal ramping: The amount of power a generator can dispatch between two consecutive periods should be in the range of `plus minus` the ramping value of the generator multiplied by the inter-temporal ramping constant. o Intercase ramping: The amount of power a generator can dispatch between two consecutive periods should be in the range of plus minus the ramping value of the generator multiplied by the intercase ramping constant. • Problems: Following are the list of problems that the software is capable to solve. o Direct current optimal power flow (DCOPF): DCOPF finds the optimal economic dispatch for one period. o Multi-period direct current optimal power flow (MPDCOPF): MPDCOPF finds the optimal economic dispatch for all the periods that are define as a whole. o Unit commitment: The unit commitment option can be used in combination with ``multi-period`` to know the status and the dispatch that optimize the operation of the system for the whole period. o Security constraint: calculates the optimal economic dispatch that fulfills N-1 criteria. If the intercase ramping constant is non zero, the program applies post-contingency corrective rescheduling.
Read data	This module reads the input files that define the case. Each case is defined by six files.
Output	This module produces six output files with the results of the optimization problem

Figure 12-1 shows the flow chart of the Program operation for Economic Evaluation of Power Systems.

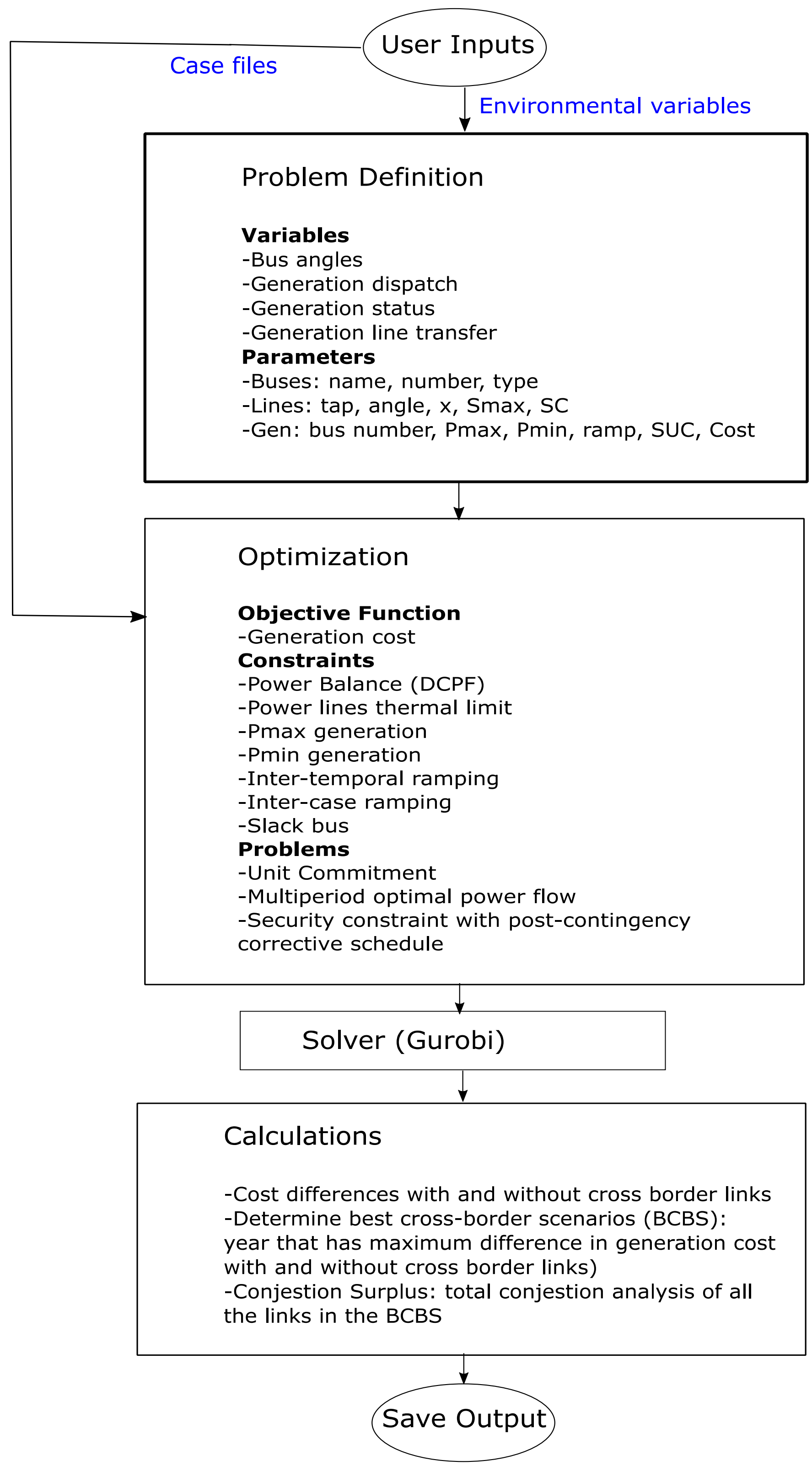


Figure 12-1: Flow Chart of the Program for Economic Evaluation of Power Systems

12.2 Validation

The results from the optimization program were validated through comparisons with the results from the Matpower optimization tool. The program was tested for three cases: A six bus case tested for both normal operation and with congestion, as well as a 300 bus case. The tables below show the comparisons with the results from MHI program and Matpower. It can be seen that the results from MHI program agrees with those from Matpower.

12.2.1 Six Buses System Example

The first test case was a six-bus system with three generators and three loads. The configuration of the test system as well as the results from the optimization program at MHI is shown in Figure 12-2. Table 12-2 and Table 12-3 show the comparisons between the results from MHI's optimization program and Matpower. One can see that the results agree with each other.

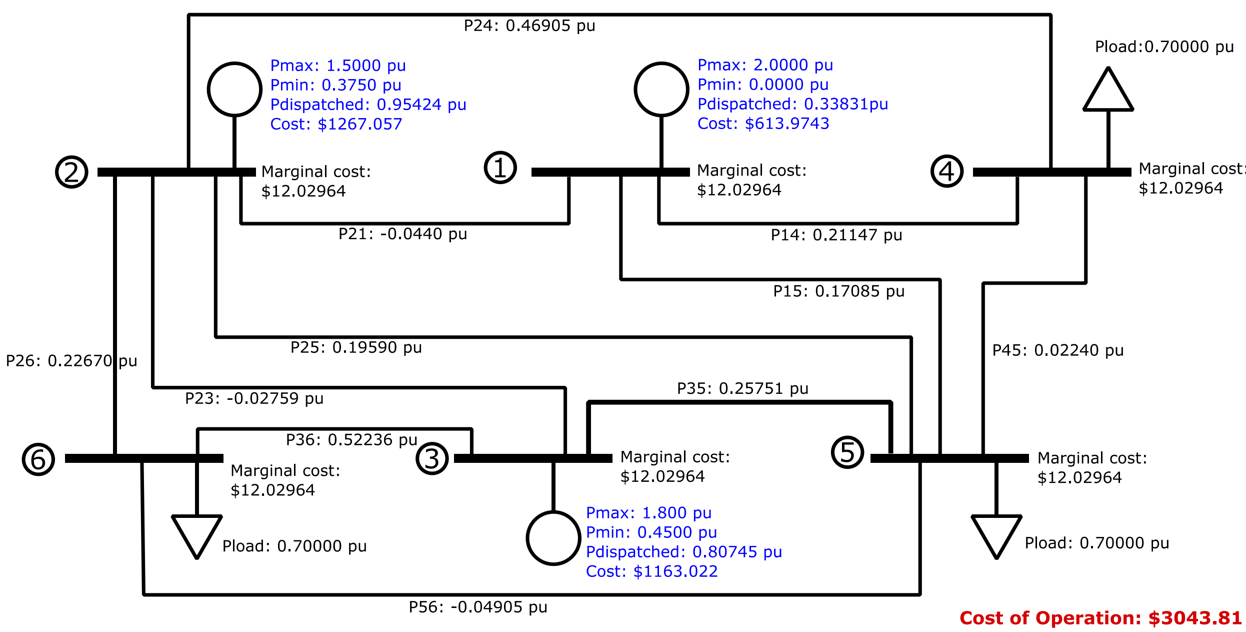


Figure 12-2: Schema of the 6 Bus System with the Input Values and the Economic and Power Flow Results

Figure 12-3 shows the quadratic cost functions of the three generators, and Figure 12-4 the local marginal prices in each bus for the optimized solution.

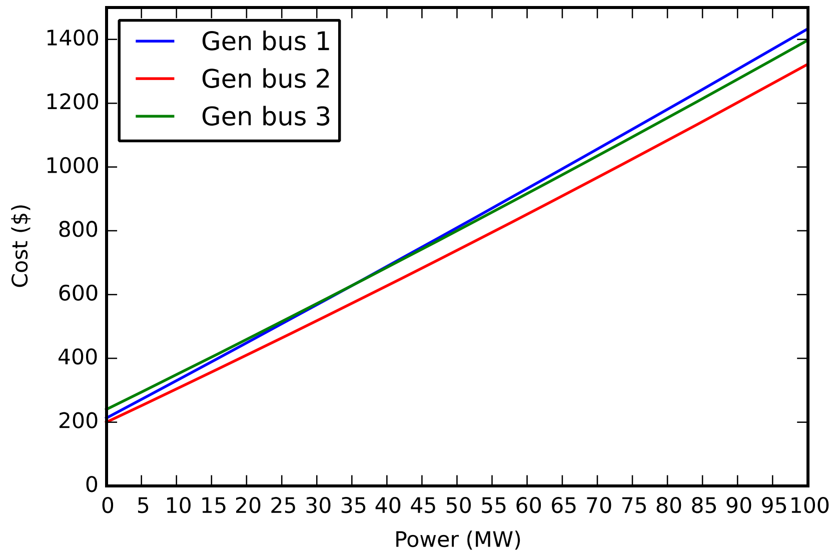


Figure 12-3: Production Cost Functions for the Three Generators of the Six Bus System

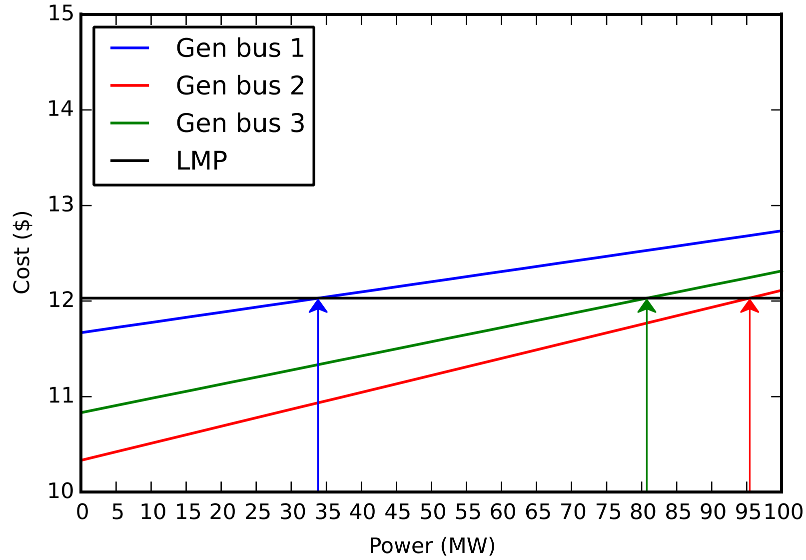


Figure 12-4: Marginal Cost Functions for the Three Generators of the Six Bus System with Their Dispatch and Bus Local Marginal Prices

Table 12-2: Result Comparison of the Economic Dispatch between MHI Program and Matpower for the Six Bus System

Bus number	Angle (degrees)			Local Marginal prices ($/MWh)		
	MHI	Matpower	Difference	MHI	Matpower	Difference
1	0	0	0	12.03	12.03	0
2	0.504	0.504	-0.000	12.03	12.03	0
3	0.899	0.899	-0.000	12.03	12.03	0
4	-2.423	-2.423	0.000	12.03	12.03	0
5	-2.937	-2.937	-0.000	12.03	12.03	0
6	-2.094	-2.094	-0.000	12.03	12.03	0

Generation Dispatch (pu)			
Bus number	**MHI**	**Matpower**	**Difference**
1	0.3383	0.3383	0
2	0.9542	0.9542	0
3	0.8075	0.8074	0.0001

Table 12-3: Result Comparison of the Power Flow MHI Program and Matpower for the Six Bus System

Power line number	From bus	To bus	Power flow (pu)		
			MHI	**Matpower**	**Difference**
1	1	2	-0.044	-0.044	0
2	1	4	0.2115	0.2115	0
3	1	5	0.1709	0.1708	-0.0001
4	2	3	-0.0276	-0.0276	0
5	2	4	0.5109	0.5109	0
6	2	5	0.2002	0.2002	0
7	2	6	0.2267	0.2267	0
8	3	5	0.2575	0.2575	0
9	3	6	0.5224	0.5224	0
10	4	5	0.0224	0.0224	0
11	5	6	-0.0491	-0.0491	0

12.2.2 Six Buses System with a Constrained Solution

The second test case is the six bus system with modifications to the power limits in one generator and one branch such that the system becomes more constrained. The configuration of the test system as well as the results from the optimization program at MHI is shown in Figure 12-5. Table 12-3 and Table 12-4 show the comparisons between the results from MHI's optimization program and Matpower. It can be seen that the results agree with each other.

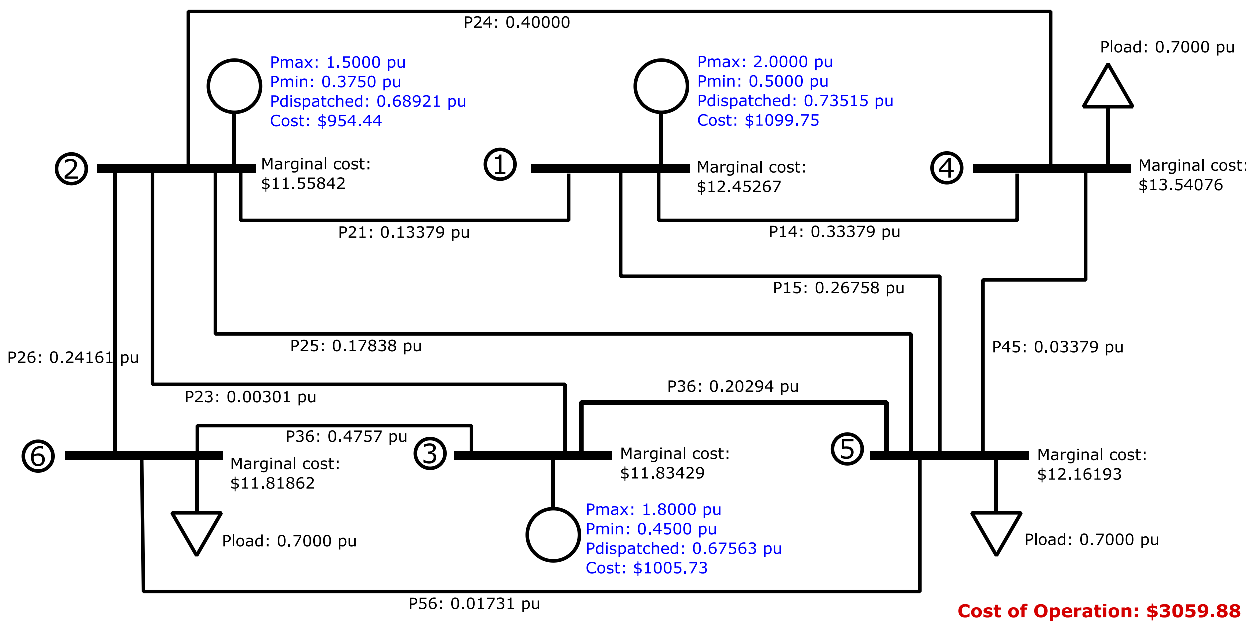


Figure 12-5: Schema of the Constrained Solution for the 6 Bus System

Figure 12-6 shows that when the transmission system is constrained the local marginal prices in each bus are different. The arrows point the operating point of each generator that fix the local marginal price for the buses where they are connected.

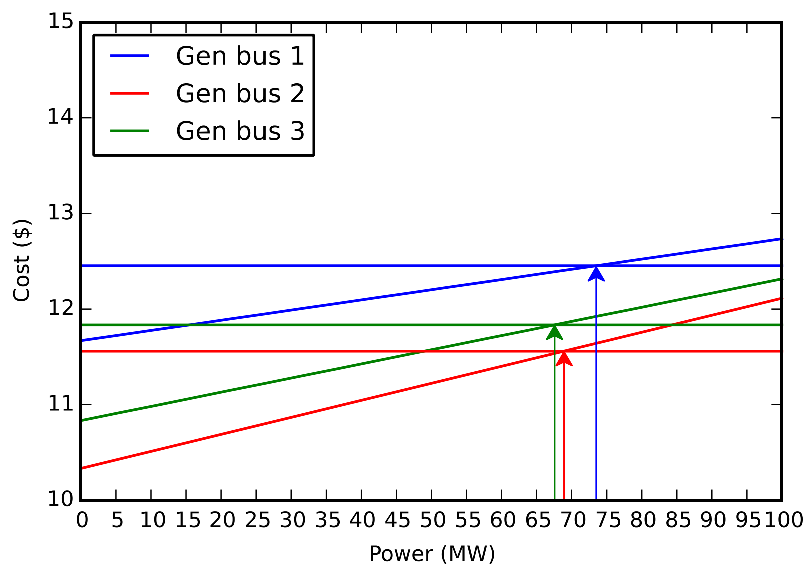


Figure 12-6: Marginal Cost Functions for the Three Generators of the Constrained Solution for the Six Buses System with Their Dispatch and Bus Local Marginal Prices

Table 12-4: Result Comparison for the IEEE 6 Bus Test System (Bus Variables and Generation Dispatch)

Bus number	Angle (degrees)			Local Marginal prices ($/MWh)		
	MHI	Matpower	Difference	MHI	Matpower	Difference
1	0	0	0	12.453	12.453	0
2	-1.533	-1.533	0.00	11.558	11.558	0
3	-1.576	-1.576	0.000	11.834	11.834	0
4	-3.825	-3.825	0.000	13.541	13.541	0
5	-4.599	-4.599	0.000	12.162	12.162	0
6	-4.302	-4.302	-0.000	11.819	11.819	0
Generation Dispatch						
Bus number	**MHI**			**Matpower**		**Difference**
1	0.7352			0.7352		0
2	0.6892			0.6892		0
3	0.6756			0.6756		0

Table 12-5: Result Comparison for the IEEE 6 Bus Test System (Branch Power Flow)

Power line number	From bus	To bus	Power flow		
			MHI Program to be used for the study	Matpower	Difference
1	1	2	13.38	13.38	0
2	1	4	33.38	33.38	0
3	1	5	26.76	26.76	0
4	2	3	0.3	0.3	0
5	2	4	40	40	0
6	2	5	17.84	17.84	0
7	2	6	24.16	24.16	0
8	3	5	20.29	20.29	0
9	3	6	47.57	47.57	0
10	4	5	3.38	3.38	0
11	5	6	-1.73	-1.73	0

12.2.3 Three Hundred Bus System

The third test case uses a 300 bus system. Table 12-6 and Table 12-7 show the comparisons between the results from MHI's optimization program and Matpower. One can see that the results agree with each other.

Table 12-6: Result Comparison for the 300 Bus IEEE Test System (Bus Variables and Generation Dispatch – Comparison results are shown for selected buses)

Bus number	Angle (degrees)			Local Marginal prices ($/MWh)		
	MHI	Matpower	Difference	MHI	Matpower	Difference
1	19.543	19.542	-0.001	20.473	20.473	0
2	26.671	26.67	-0.001	40.828	40.828	0
3	24.593	24.591	-0.002	39.582	39.582	0

Bus number	Angle (degrees)			Local Marginal prices ($/MWh)		
	MHI	Matpower	Difference	MHI	Matpower	Difference
4	22.558	22.557	-0.001	39.664	39.664	0
5	19.2	19.198	-0.002	50.724	50.724	0
6	25.704	25.702	-0.002	40.766	40.766	0
7	24.255	24.253	-0.002	40.507	40.508	0.001
8	21.531	21.53	-0.001	41.691	41.692	0.001
9	19.438	19.437	-0.001	47.485	47.485	0
10	22.013	22.011	-0.002	42.187	42.187	0
11	21.145	21.144	-0.001	44.468	44.469	0.001
12	24.085	24.083	-0.002	40.907	40.907	0
13	18.797	18.796	-0.001	43.09	43.091	0.001
14	13.29	13.289	-0.001	41.074	41.074	0
15	8.899	8.898	-0.001	40.457	40.457	0
16	14.596	14.595	-0.001	39.984	39.984	0
17	5.092	5.091	-0.001	40.457	40.457	0
19	20.111	20.109	-0.002	40.835	40.835	0
20	17.579	17.577	-0.002	41.712	41.713	0.001

Generation Dispatch			
Bus number	MHI	Matpower	Difference
8	0.8457	0.8458	1E-04
10	1	1	0
20	0.8562	0.8563	1E-04
63	0.0409	0.041	0.0001
76	0.0535	0.0536	0.0001
84	3.7701	3.7702	0.0001
91	1.585	1.585	0
92	2.9483	2.9483	0
98	0.6956	0.6956	0
108	1.193	1.193	0
119	19.314	19.3129	-0.0011
124	2.4016	2.4016	0
125	0.0066	0.0067	0.0001
138	0.0094	0.0095	1E-04
141	2.8137	2.8137	0
143	6.9764	6.9766	0.0002

Table 12-7: Result Comparison for the 300 Bus IEEE Test System (Branch Power Flow) - Comparison results are shown for selected buses

Power line number	From bus	To bus	Power flow		
			MHI Program to be used for the study	Matpower	Difference
1	37	9001	0.5	0.5	0
2	9001	9005	0.17	0.17	0
3	9001	9006	0.26	0.26	0
4	9001	9012	0.08	0.08	0
5	9005	9051	0.27	0.27	0
6	9005	9052	-0.3	0.3	0.6

Power line number	From bus	To bus	Power flow		
			MHI Program to be used for the study	Matpower	Difference
7	9005	9053	0.19	0.19	0
8	9005	9054	-0.5	-0.5	0
9	9005	9055	-0.08	-0.08	0
10	9006	9007	0.09	0.09	0
11	9006	9003	0.08	0.08	0
12	9006	9003	0.08	0.08	0
13	9012	9002	0.02	0.02	0
14	9012	9002	0.02	0.02	0
15	9002	9021	-0.07	0.07	0.14
16	9021	9023	-0.01	0.01	0.02
17	9021	9022	-0.02	0.02	0.04
18	9002	9024	-0.01	0.01	0.02
19	9023	9025	0	0	0
20	9023	9026	0	0	0

13 Appendix D - Daily Load Curves

13.1 Bangladesh

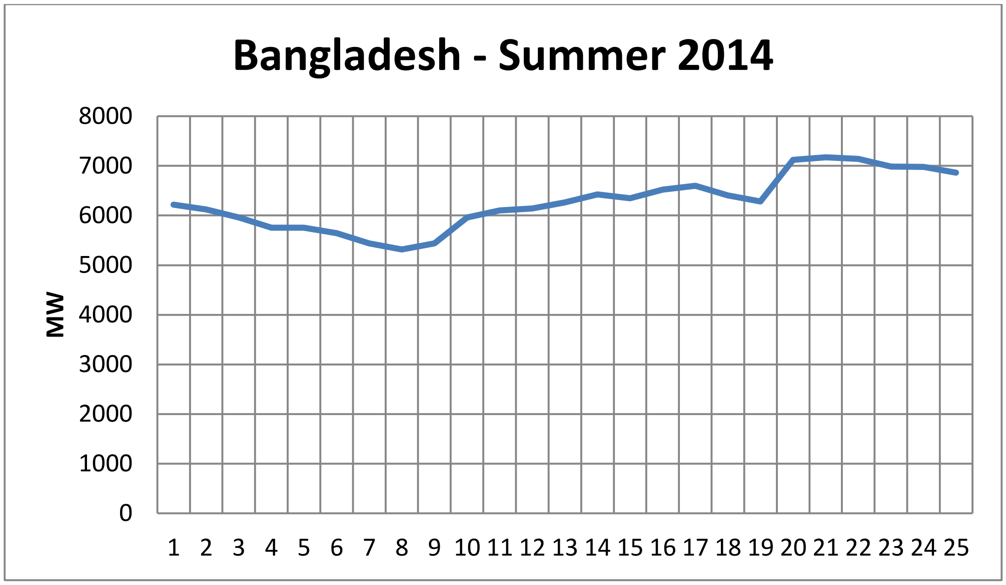


Figure 13-1: Daily load curve during summer season in Bangladesh

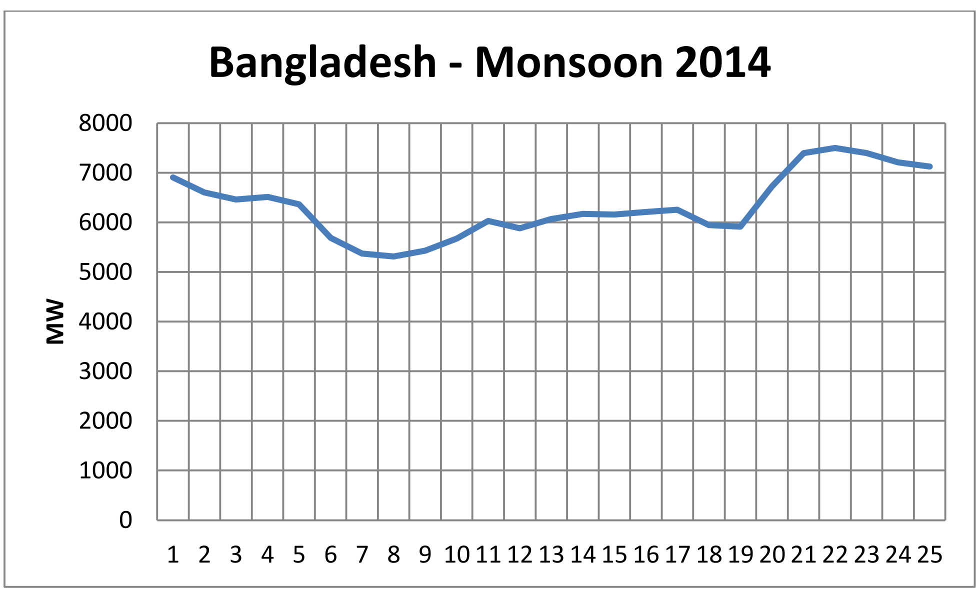


Figure 13-2: Daily load curve during monsoon season in Bangladesh

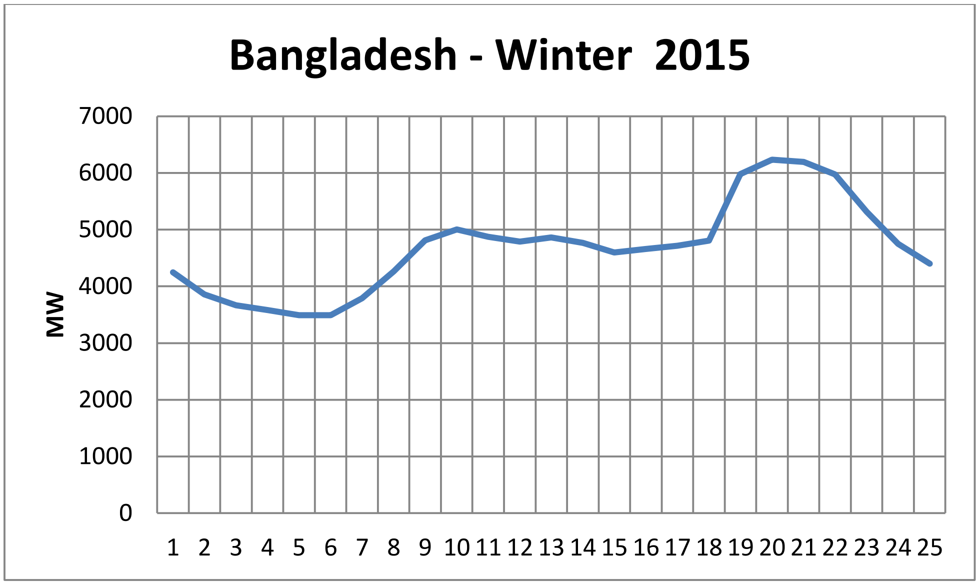


Figure 13-3: Daily load curve during winter season in Bangladesh

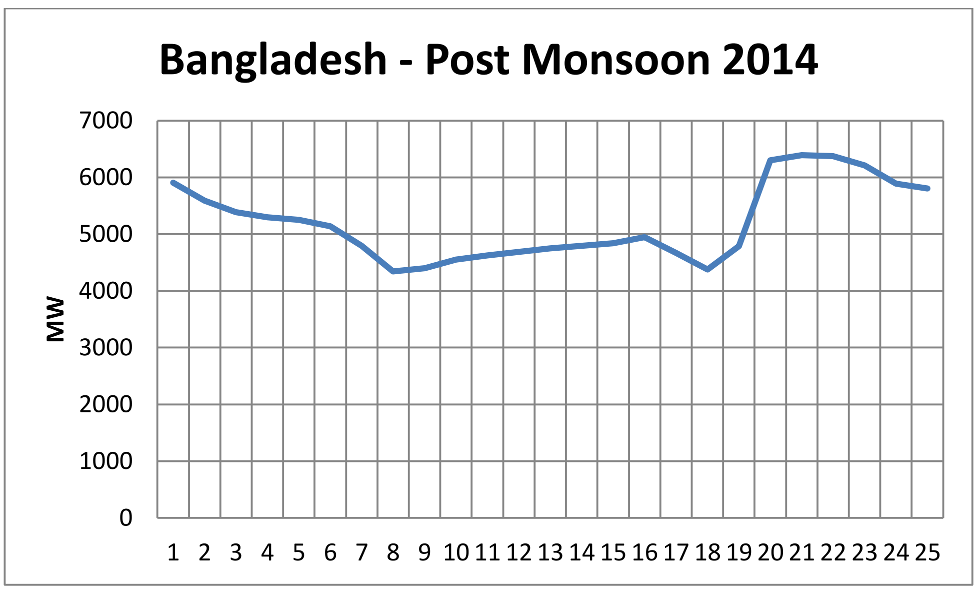


Figure 13-4: Daily load curve during post monsoon season in Bangladesh

13.2 India

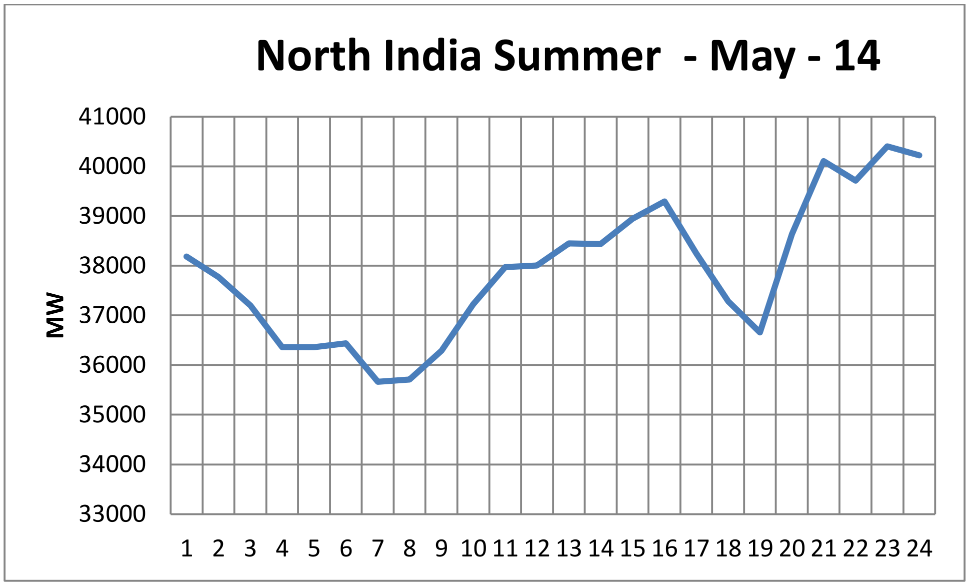


Figure 13-5: Daily load curve during summer season in North region of India

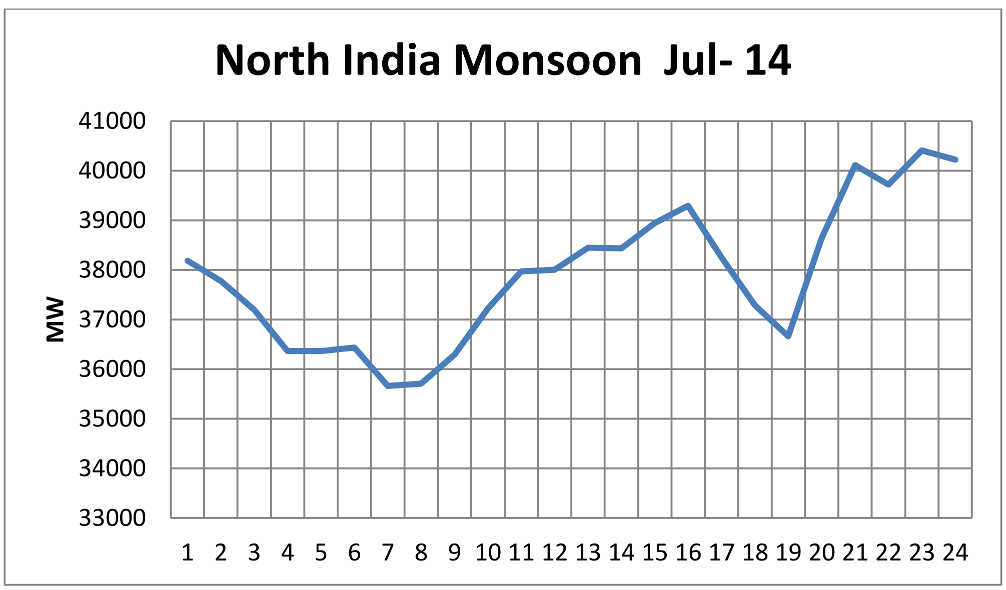


Figure 13-6: Daily load curve during monsoon season in North region of India

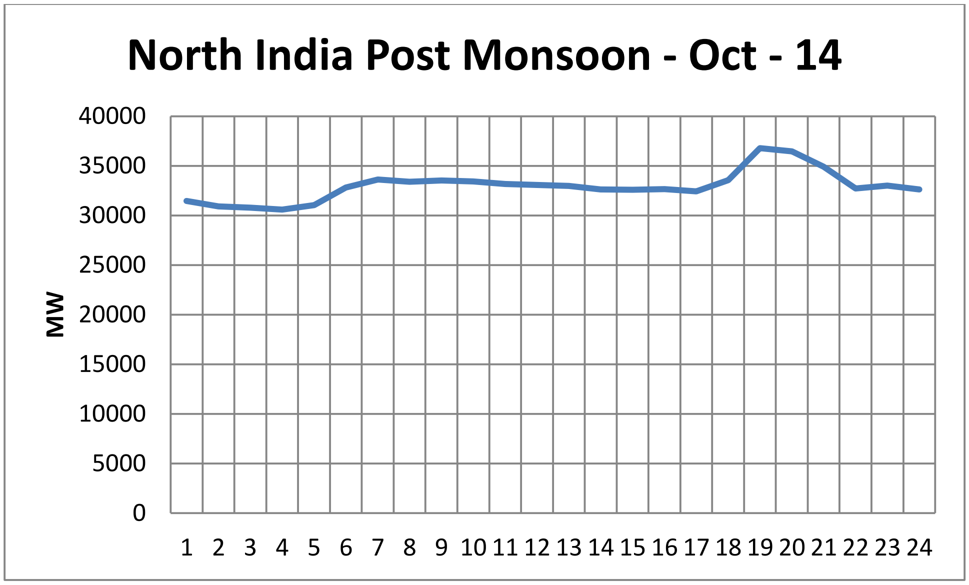


Figure 13-7: Daily load curve during post monsoon season in North region of India

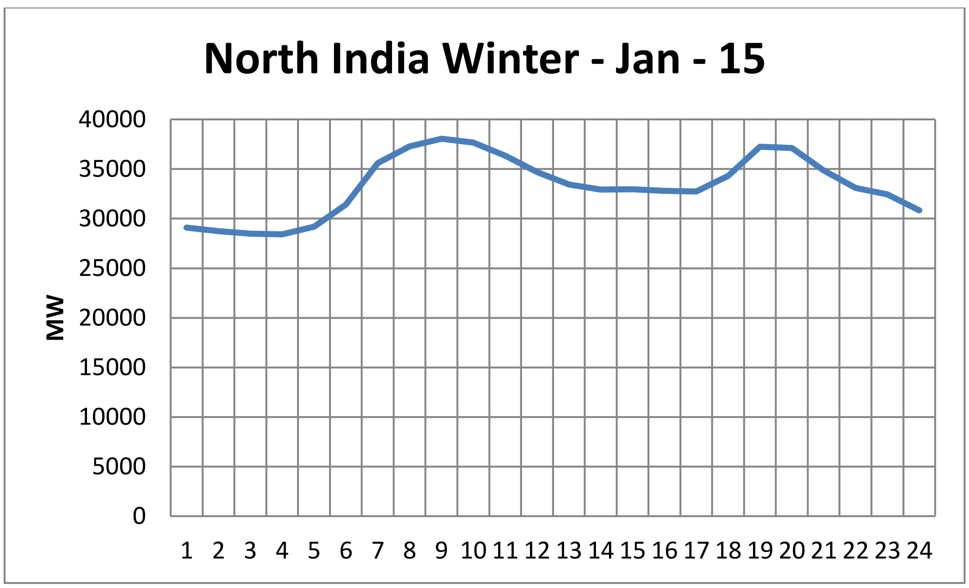


Figure 13-8: Daily load curve during winter season in North region of India

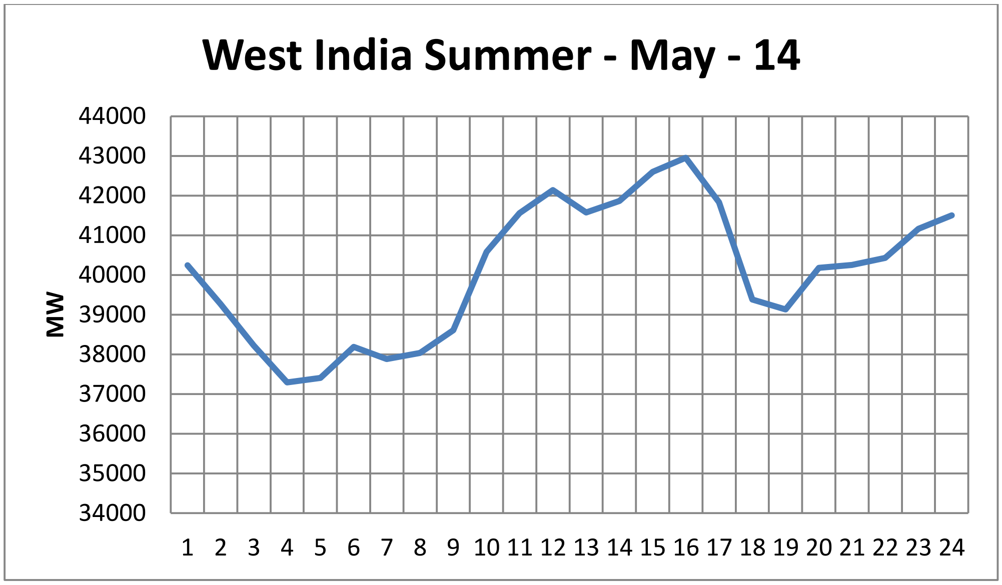


Figure 13-9: Daily load curve during summer season in West region of India

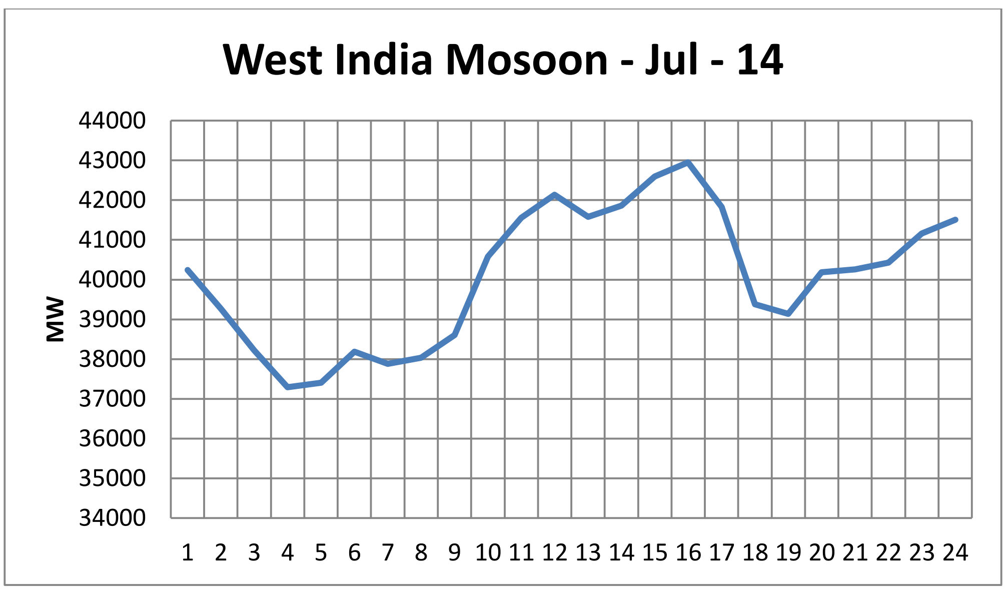


Figure 13-10: Daily load curve during monsoon season in West region of India

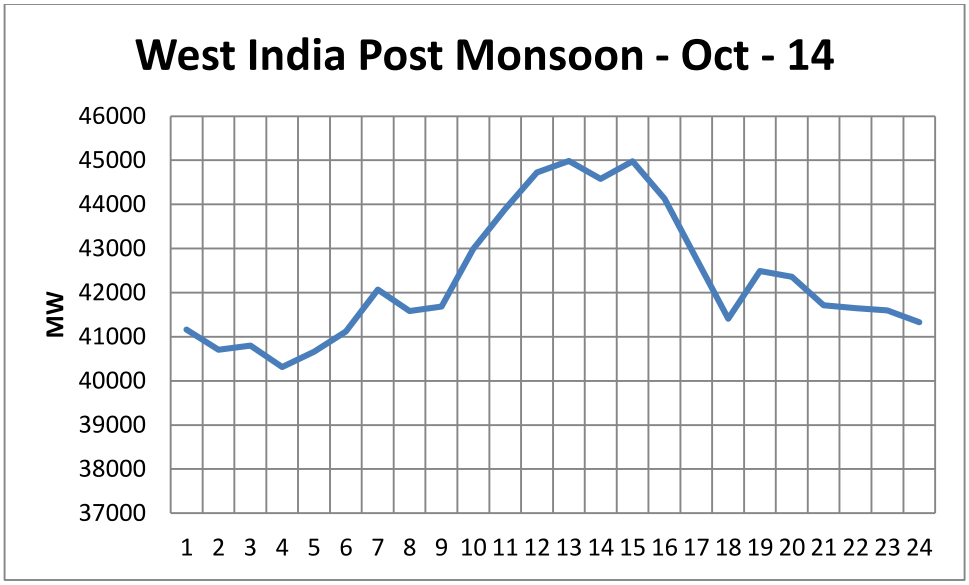


Figure 13-11: Daily load curve during post monsoon season in West region of India

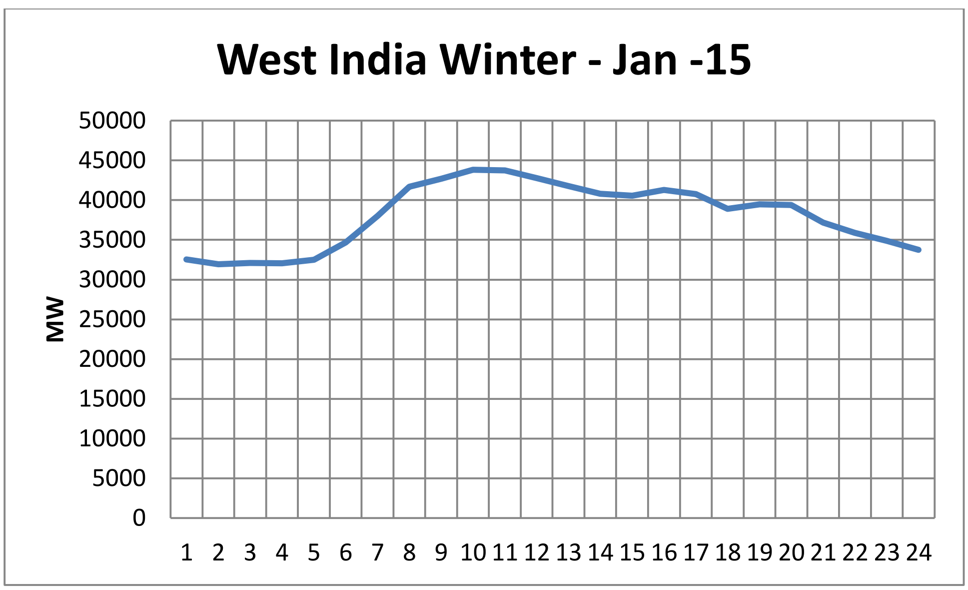


Figure 13-12: Daily load curve during winter season in West region of India

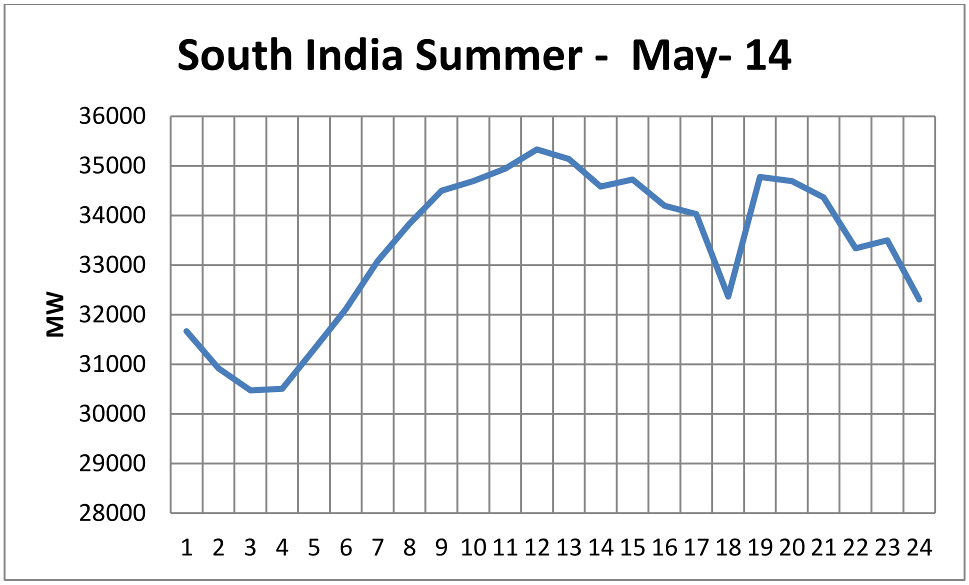


Figure 13-13: Daily load curve during summer season in South region of India

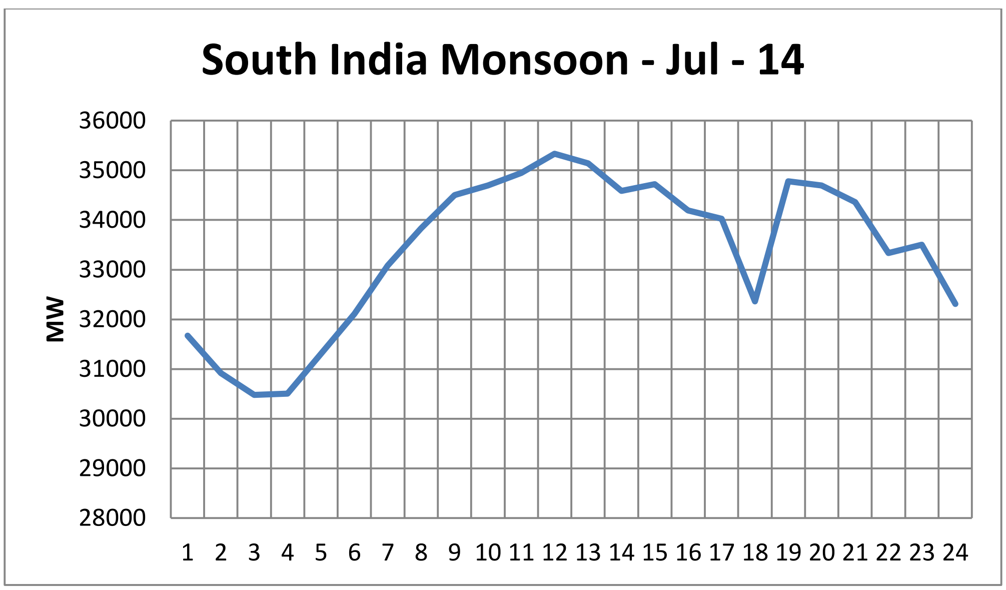


Figure 13-14: Daily load curve during monsoon season in South region of India

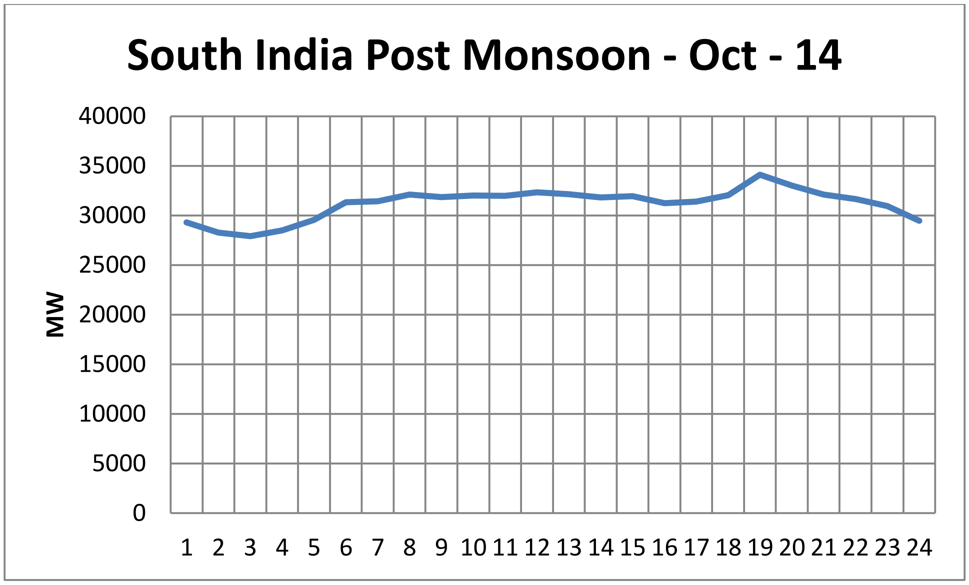


Figure 13-15: Daily load curve during post monsoon season in South region of India

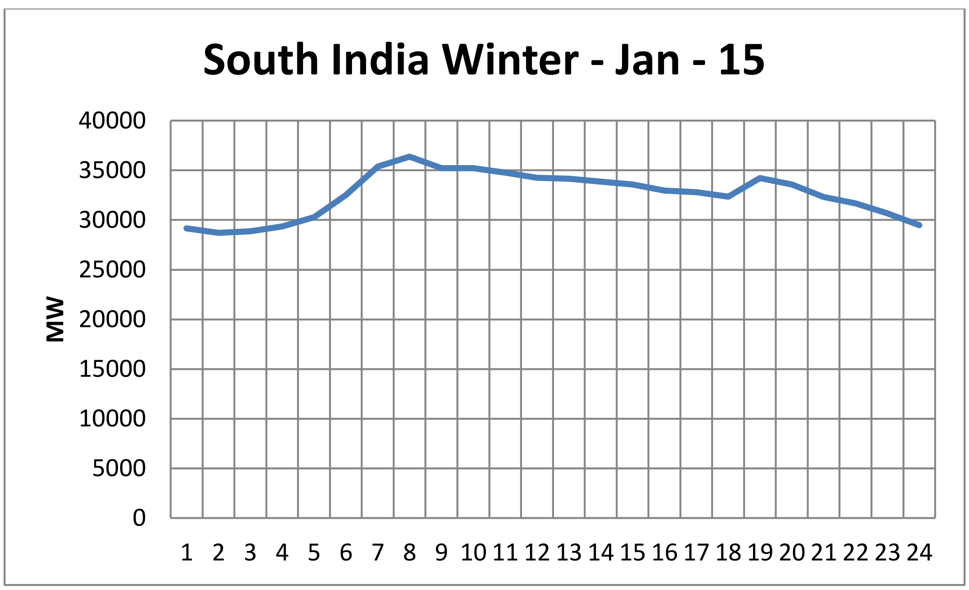


Figure 13-16: Daily load curve during winter season in South region of India

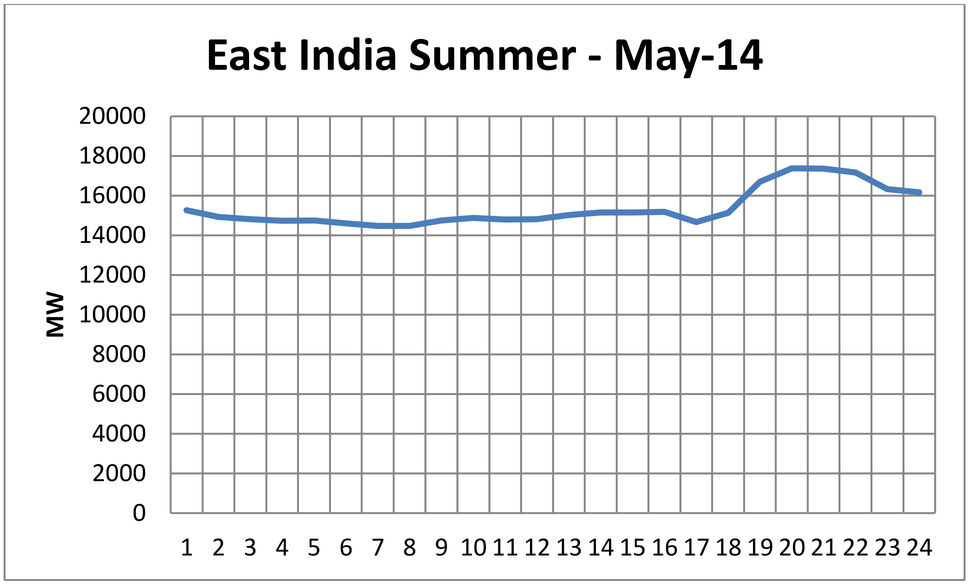


Figure 13-17: Daily load curve during summer season in East region of India

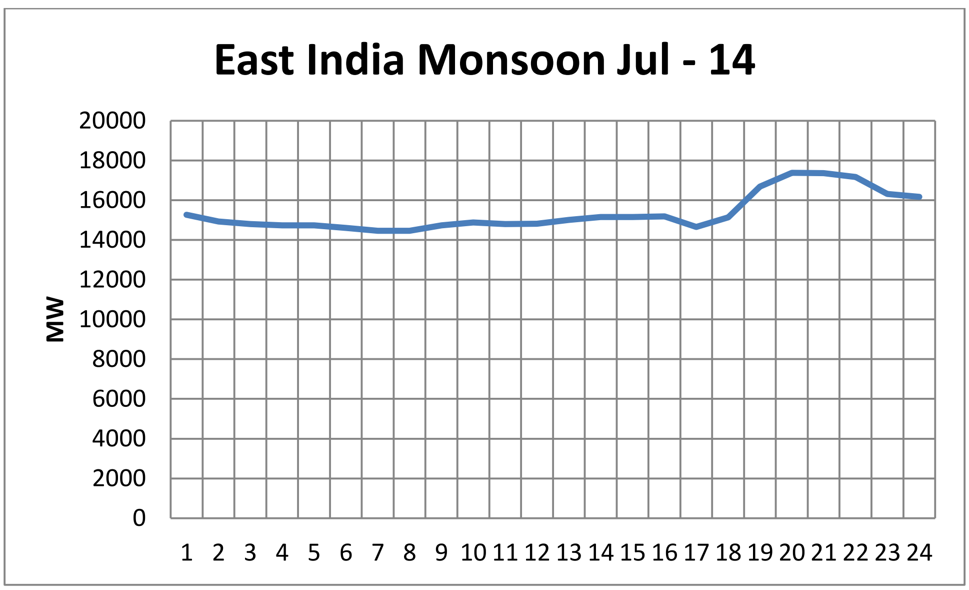


Figure 13-18: Daily load curve during monsoon season in East region of India

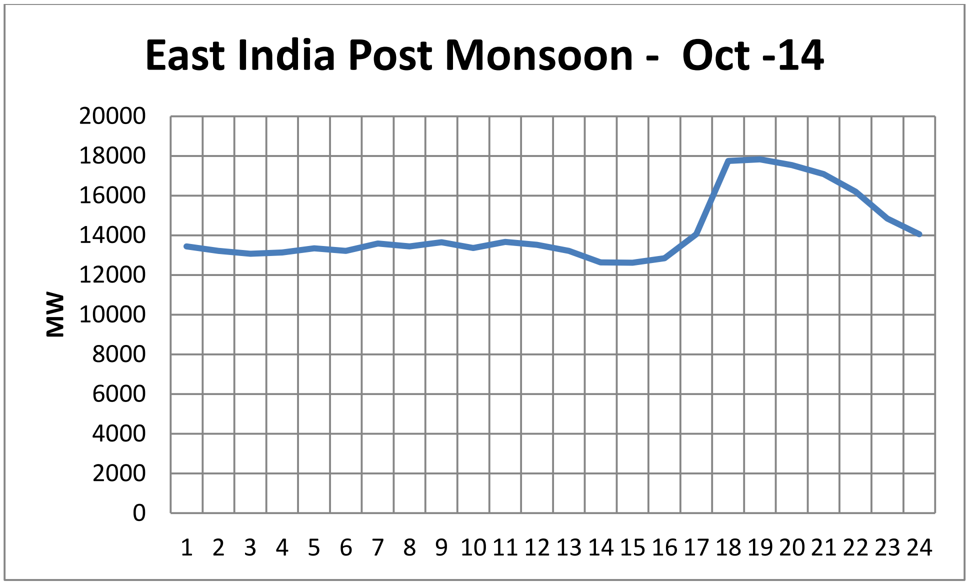


Figure 13-19: Daily load curve during post monsoon season in East region of India

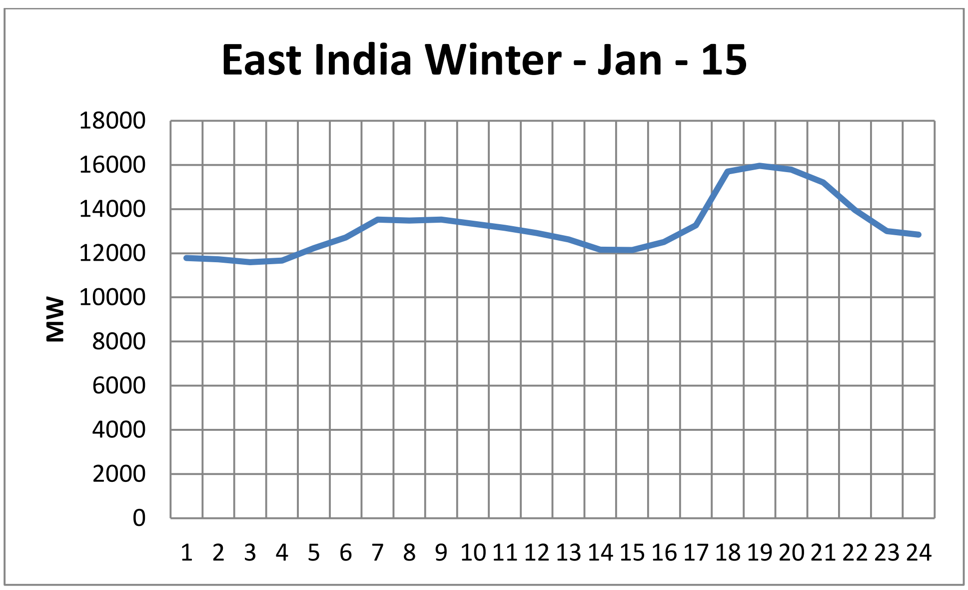


Figure 13-20: Daily load curve during winter season in East region of India

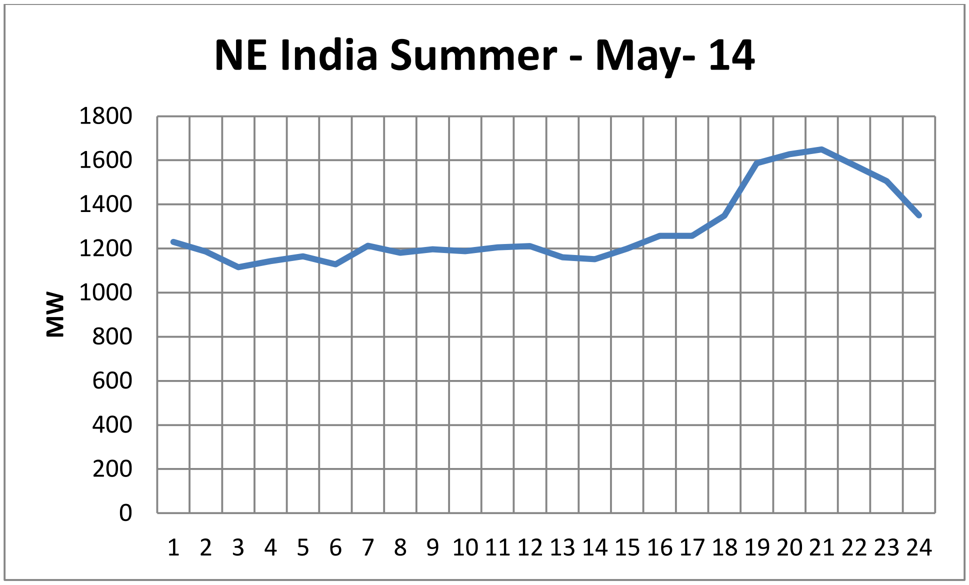


Figure 13-21: Daily load curve during summer season in North-East region of India

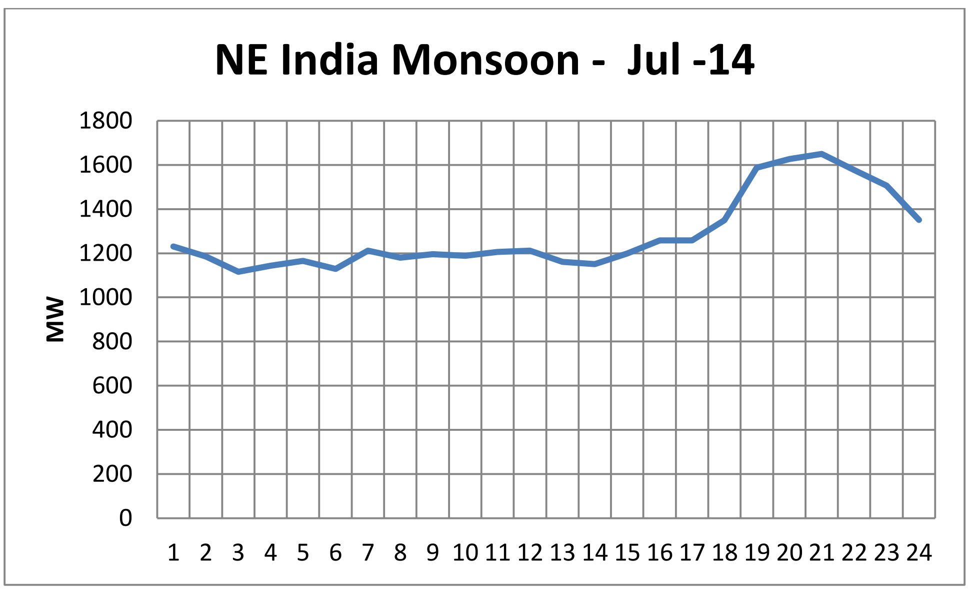


Figure 13-22: Daily load curve during monsoon season in North-East region of India

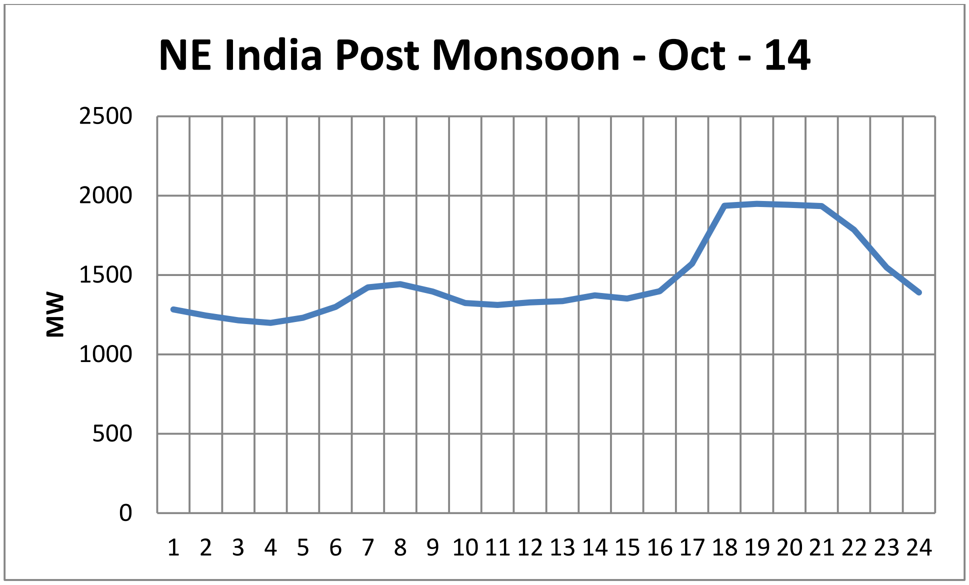


Figure 13-23: Daily load curve during post monsoon season in North-East region of India

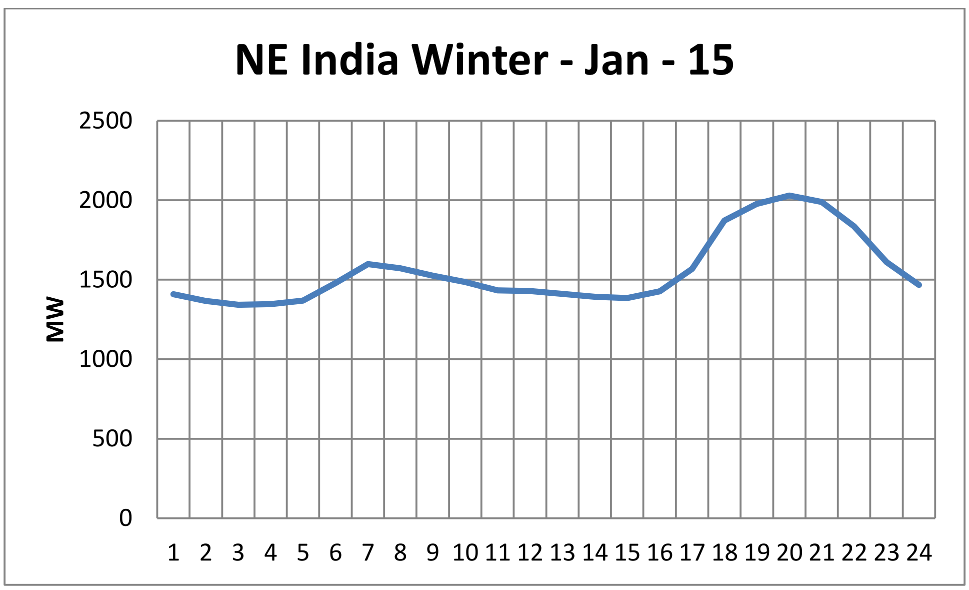


Figure 13-24: Daily load curve during winter season in North-East region of India

13.3 Nepal

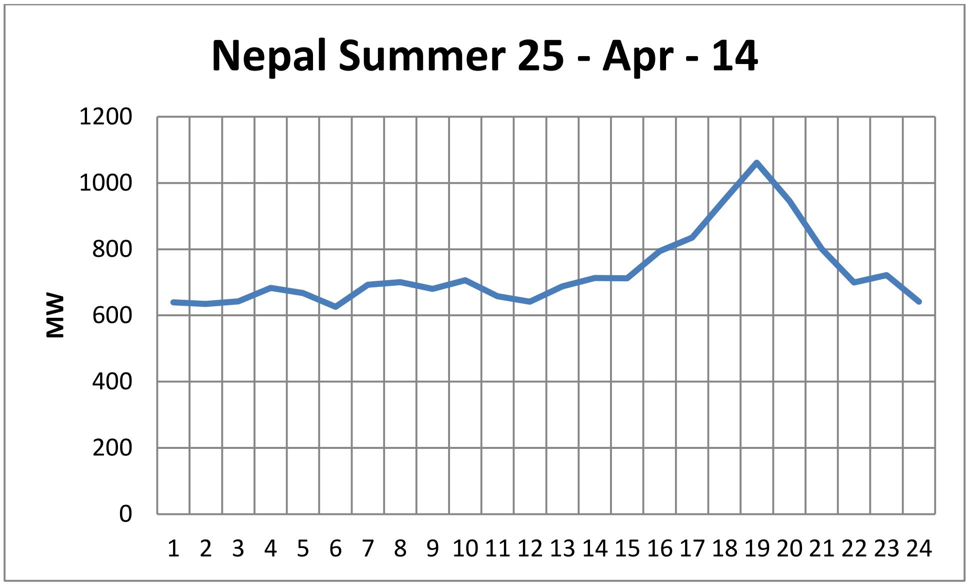


Figure 13-25: Daily load curve in April 25, 2014 in Nepal

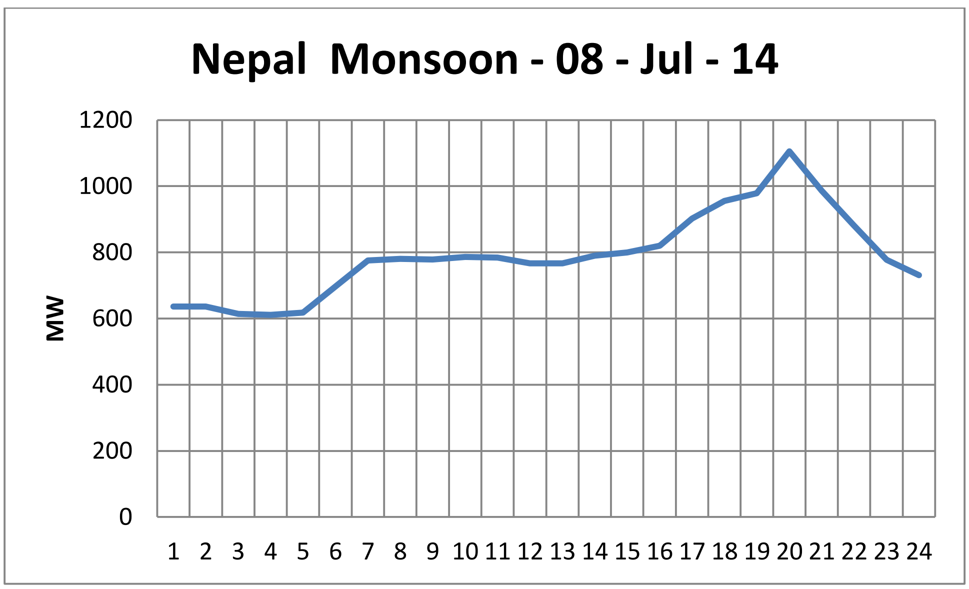


Figure 13-26: Daily Load curve in July 8, 2014 in Nepal

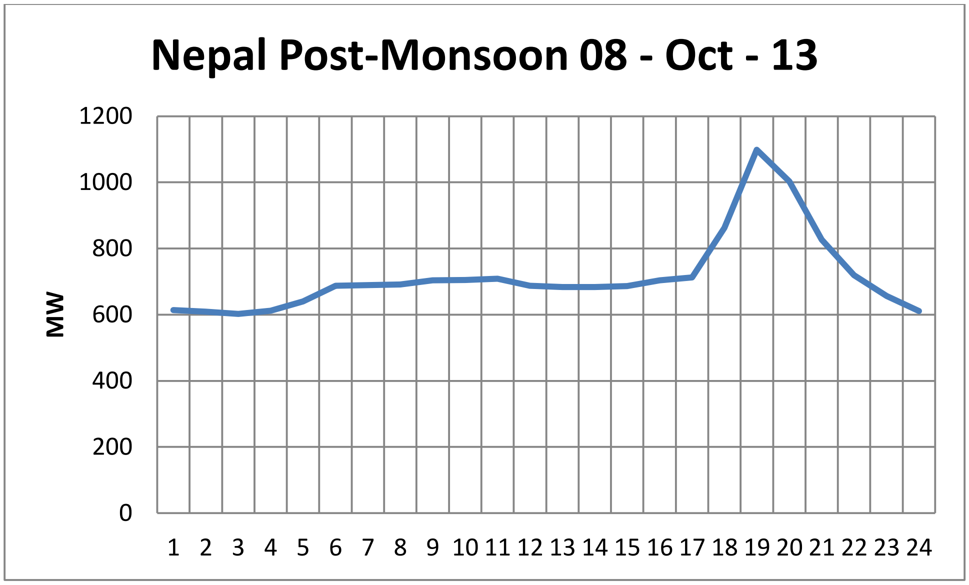


Figure 13-27: Daily load curve in October 8, 2013 in Nepal

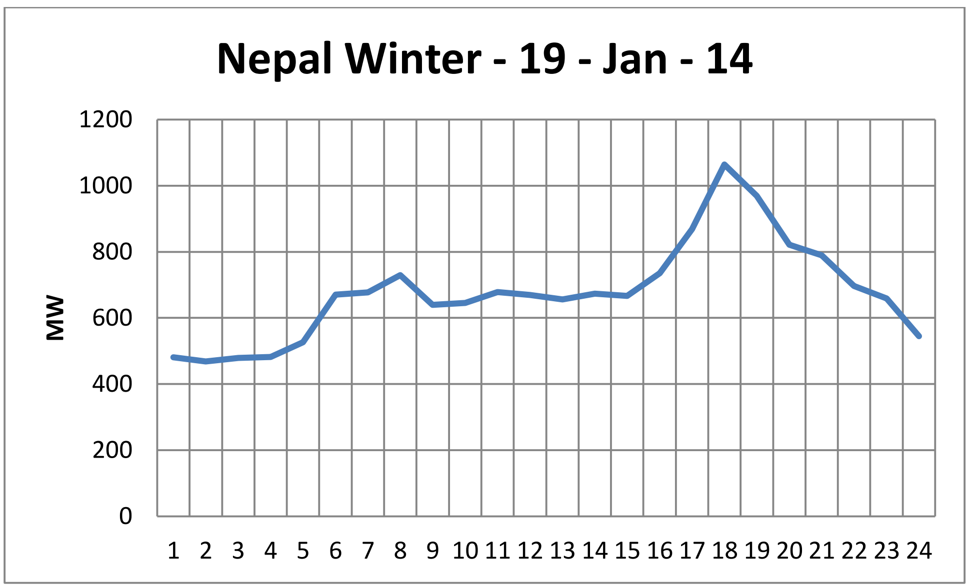


Figure 13-28: Daily load curve in January 19, 2014 in Nepal

13.4 Afghanistan

Figure 13-29 shows the selected daily curve for Afghanistan. This was extracted from [26] and used for all seasons.

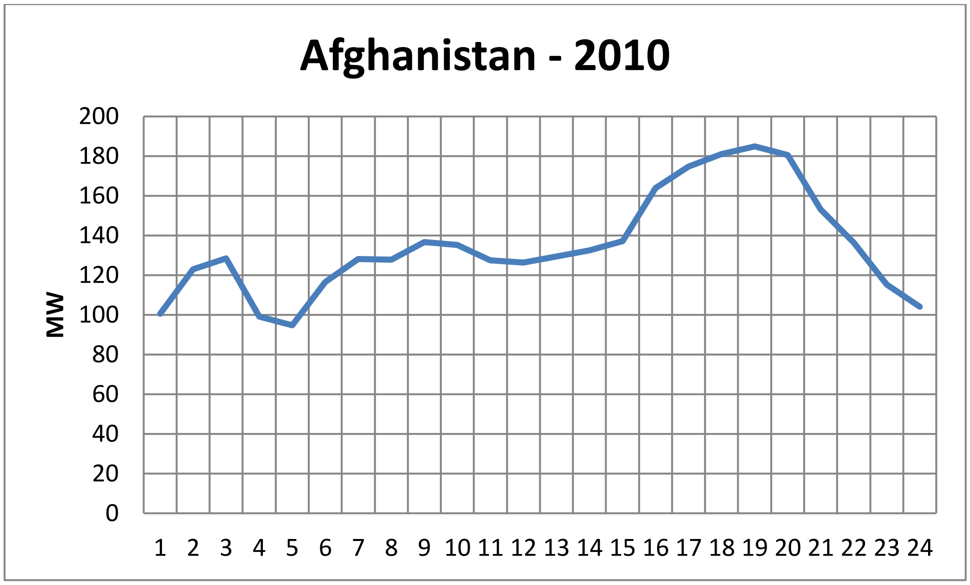


Figure 13-29: Daily load curve in Afghanistan

13.5 Bhutan

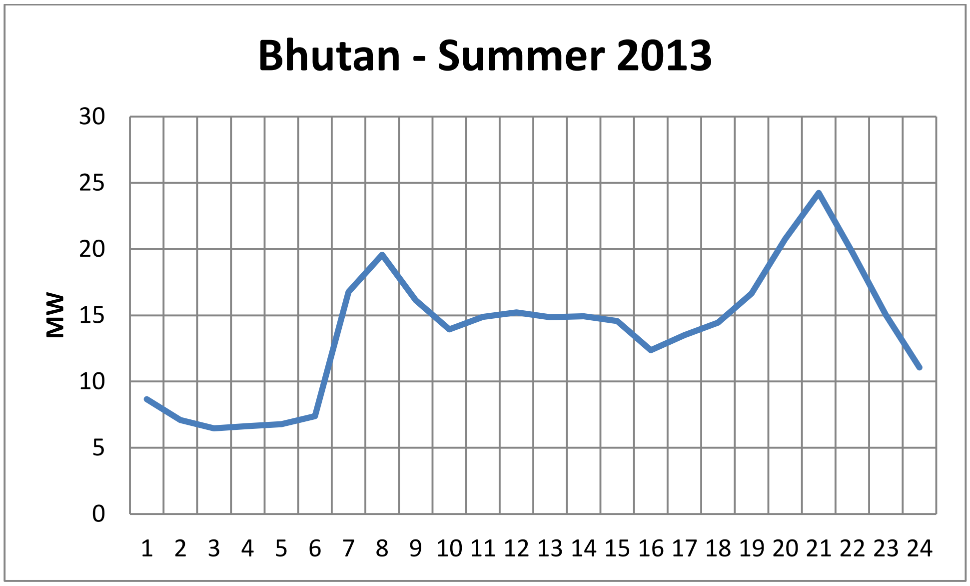


Figure 13-30: Summer daily load curve in Bhutan

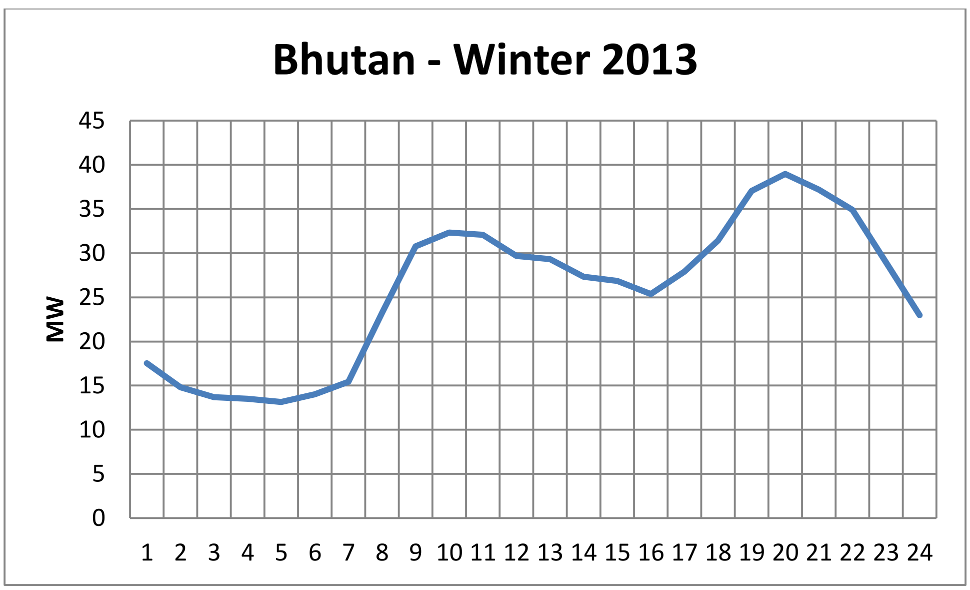


Figure 13-31: Winter daily load curve in Bhutan

13.6 Pakistan

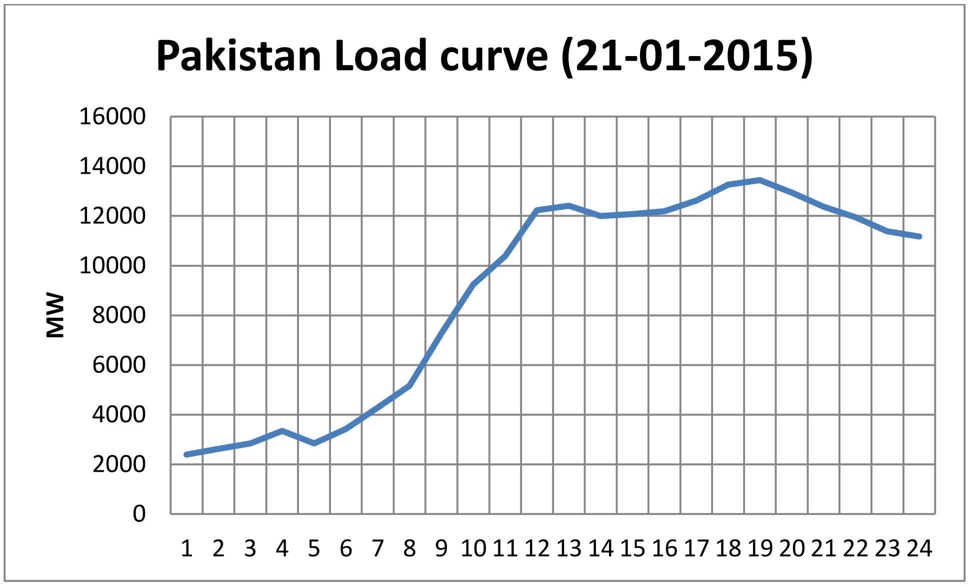


Figure 13-32: Daily load curve on January 21, 2015 in Pakistan

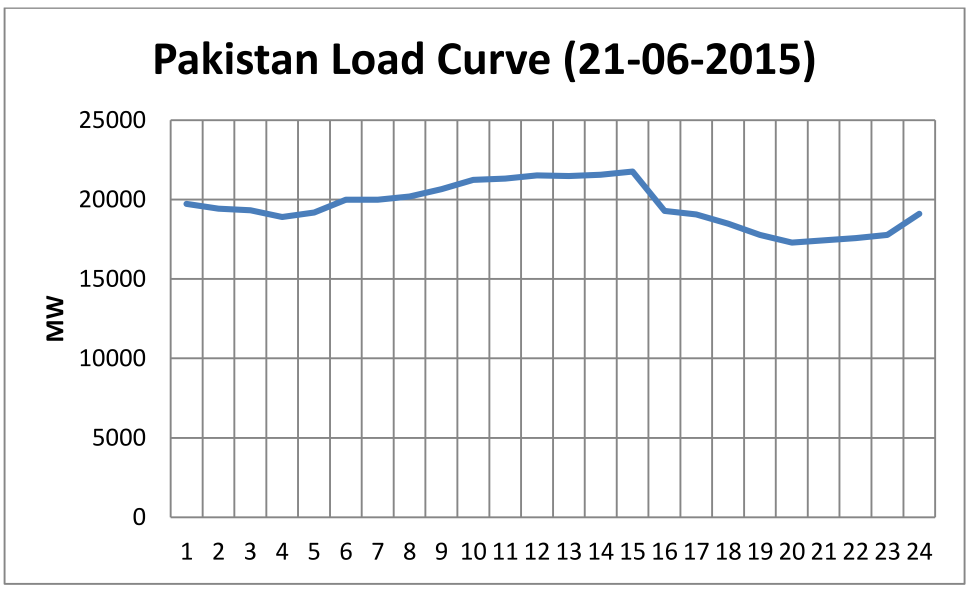


Figure 13-33: Daily load curve on June 21, 2015 in Pakistan

14 Appendix E - Master List of Cross-Border Connections

Table 14-1: Full list of identified potential cross-border connections. This is the first set of cross-border transmission links that were under consideration

Id	From Substation (Country)	To Substation (Country)	Remarks	Source	Comm. year
1	Baharampur (I)	Bheramara (BA)	Existing HVDC back to back station capacity at Bheramara is being expanded to1000MW adding 2nd block of 500MW		2017
2	Surjyamaninagar (I)	Comilla (BA)	400kV AC line is under construction, initially will be energised at 132kV and bring 100MW power on radial mode from Tripura (I)		2016
3	Rangia/Rowta (I), Barakupuria (BA)	Barakupuria (BA), Muzaffarnagar (I, Uttar Pradesh)	800 kV 3 terminals HVDC	[22] [17]	
4	Bongaigao (I), Barakupuria (BA)	Barakupuria, Purnea (I)	765 kV AC line and HVDC back-to-back station at Barapukuria	[22] [17]	
5	Silchar (I)	Meghnaghat/Bhulta-Bheramara (BA)	400 kV AC line and HVDC back-to-back station at Meghnaghat/Bhulta	[22]	
6	Muzaffarpur (I)	Dhalkebar (N)	Existing 400 kV AC line		2014
7	Ramnagar (I)	Gandak (N)	Existing 132 KV AC line		
8	Tanakpur (I)	Mahendranagar (N)	Existing 132 KV AC line		
9	Koshi (I)	Duhabi (N)	Existing 132 KV AC line		
10	Muzaffarpur (I)	Duhabi (N)	400kV AC. The purpose of this link is to evacuate power from Tamakoshi (N) and Arun (N).	[23]	2022
11	Purnea (I)	Duhabi (N)	400kV AC. The purpose of this link is to evacuate power from Tamakoshi (N) and Arun (N).	[23]	2022
12	Barneilly (I)	Lumki (N)	400kV AC. The purpose of this link is to evacuate power from U. Karnaly (N)	[23]	2022
13	Barneilly (I)	Attariya (N)	400kV AC. The purpose of this link is to evacuate power from U. Karnaly (N)	[23]	2022
14	Gorakhpur (I)	Butwal (N)	400kV AC. The purpose of this link is to evacuate power from Marsyandgi (N)	[22][23] [24]	2022
15	Gorakhpur (I)	N. Bardghat (N)	400 kV HVDC Bipole. The purpose of this link is to evacuate power from Marsyandgi (N)	[22][23]	2022
16	Meerut Lhamoi Zingkha (I)	Sankosh Main (BU)	800KV bipole HVDC	[22][3]	2030
17	Gnoida (I)	Yangbari (BU)	800kV bipole HVDC	[22][3]	2030
18	Rangia/Rowta (I)	Yangbari (BU)	400kV AC	[22][3]	2020
19	Alipurduar Lhamoi (I)	Sankhosh Main (BU)	400kV AC	[22][3]	2020
20	Alipurduar (I)	Jigmeling (BU)	400kV AC	[22][3]	2020
21	Alipurduar (I)	Amochhu (BU)	400kV AC	[22][3]	2030
22	Rangia/Rowta (I)	Nyera Amari-II (BU)	400kV AC	[22][3]	2030

Id	From Substation (Country)	To Substation (Country)	Remarks	Source	Comm. year
23	Rangia/Rowta (I)	Manas RS-I (BU)	400kV AC	22][3]	2030

15 Appendix F – Annuitized Project Costs and Benefit-Cost Ratios

15.1 IBA India – Bangladesh cross-border transmission link

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2020	40,316.40	40,638.08	321.68	376.66	233.87	1.38
2021	36,651.27	36,943.71	292.43	376.66	212.61	1.38
2022	38,187.61	38,428.74	241.12	376.66	193.28	1.25
2023	34,716.01	34,935.22	219.20	376.66	175.71	1.25
2024	31,560.01	31,759.29	199.28	376.66	159.74	1.25
2025	30,802.91	31,439.04	636.13	376.66	145.22	4.38
2026	28,002.65	28,580.95	578.30	376.66	132.02	4.38
2027	29,501.01	29,814.23	312.93	376.66	120.01	2.61
2028	26,819.10	27,103.85	284.48	376.66	109.10	2.61
2029	24,381.00	24,639.86	258.62	376.66	99.19	2.61
2030	22,164.54	22,399.87	235.11	376.66	90.17	2.61

15.2 IBU India – Bhutan cross-border transmission link

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2020	40,571.90	40,638.08	66.18	29.69	18.43	3.59
2021	36,883.54	36,943.71	60.16	29.69	16.76	3.59
2022	38,371.89	38,428.74	56.85	29.69	15.23	3.73
2023	34,883.54	34,935.22	51.68	29.69	13.85	3.73
2024	31,712.31	31,759.29	46.98	29.69	12.59	3.73
2025	31,211.29	31,439.04	227.75	29.69	11.45	19.90
2026	28,373.90	28,580.95	207.05	29.69	10.41	19.90
2027	29,813.28	29,814.23	0.66	29.69	9.46	0.10
2028	27,102.98	27,103.85	0.60	29.69	8.60	0.10
2029	24,639.07	24,639.86	0.55	29.69	7.82	0.10
2030	22,399.16	22,399.87	0.50	29.69	7.11	0.10

15.3 IN1 India – Nepal cross-border transmission link

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2020	40,447.31	40,638.08	190.76	63.09	39.17	4.87
2021	36,770.28	36,943.71	173.42	63.09	35.61	4.87
2022	38,254.43	38,428.74	174.31	63.09	32.37	5.38
2023	34,776.75	34,935.22	158.46	63.09	29.43	5.38
2024	31,615.23	31,759.29	144.06	63.09	26.75	5.38
2025	31,038.74	31,439.04	400.30	63.09	24.32	16.46
2026	28,217.03	28,580.95	363.91	63.09	22.11	16.46
2027	29,700.15	29,814.23	113.79	63.09	20.10	5.68
2028	27,000.13	27,103.85	103.45	63.09	18.27	5.68
2029	24,545.58	24,639.86	94.04	63.09	16.61	5.68
2030	22,314.16	22,399.87	85.49	63.09	15.10	5.68

15.4 IN2 India – Nepal cross-border transmission link

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2025	31,029.55	31,439.04	409.49	44.53	17.17	23.85
2026	28,208.68	28,580.95	372.27	44.53	15.61	23.85
2027	29,658.96	29,814.23	154.97	44.53	14.19	10.94
2028	26,962.69	27,103.85	140.89	44.53	12.90	10.94
2029	24,511.54	24,639.86	128.08	44.53	11.73	10.94
2030	22,283.22	22,399.87	116.43	44.53	10.66	10.94

15.5 ISL India – Sri Lanka cross-border transmission link

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2020	40,569.93	40,638.08	68.14	57.52	35.71	1.91
2021	36,881.76	36,943.71	61.95	57.52	32.47	1.91
2022	38,368.23	38,428.74	60.51	57.52	29.52	2.05
2023	34,880.21	34,935.22	55.01	57.52	26.83	2.05
2024	31,709.28	31,759.29	50.01	57.52	24.39	2.05
2025	31,210.70	31,439.04	228.34	57.52	22.18	10.30
2026	28,373.36	28,580.95	207.59	57.52	20.16	10.30
2027	29,808.73	29,814.23	5.20	57.52	18.33	0.30
2028	27,098.85	27,103.85	4.73	57.52	16.66	0.30
2029	24,635.32	24,639.86	4.30	57.52	15.15	0.30
2030	22,395.74	22,399.87	3.91	57.52	13.77	0.30

15.6 IPA India – Pakistan cross-border transmission link

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2020	40,533.27	40,638.08	104.81	38.32	23.79	4.41
2021	36,848.42	36,943.71	95.28	38.32	21.63	4.41
2022	38,307.26	38,428.74	121.47	38.32	19.66	6.18
2023	34,824.79	34,935.22	110.43	38.32	17.87	6.18
2024	31,658.90	31,759.29	100.39	38.32	16.25	6.18
2025	31,053.66	31,439.04	385.38	38.32	14.77	26.09
2026	28,230.60	28,580.95	350.35	38.32	13.43	26.09
2027	29,749.91	29,814.23	64.03	38.32	12.21	5.27
2028	27,045.37	27,103.85	58.21	38.32	11.10	5.27
2029	24,586.70	24,639.86	52.92	38.32	10.09	5.27
2030	22,351.55	22,399.87	48.11	38.32	9.17	5.27

15.7 AFPA Afghanistan - Pakistan cross-border transmission link

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2020	40,613.79	40,638.08	24.28	55.66	34.56	0.70
2021	36,921.63	36,943.71	22.07	55.66	31.42	0.70
2022	38,401.95	38,428.74	26.78	55.66	28.56	0.94
2023	34,910.87	34,935.22	24.35	55.66	25.97	0.94
2024	31,737.15	31,759.29	22.14	55.66	23.61	0.94
2025	31,374.92	31,439.04	64.12	55.66	21.46	2.99
2026	28,522.65	28,580.95	58.29	55.66	19.51	2.99
2027	29,808.47	29,814.23	5.47	55.66	17.74	0.32
2028	27,098.61	27,103.85	4.97	55.66	16.12	0.32
2029	24,635.10	24,639.86	4.52	55.66	14.66	0.32
2030	22,395.54	22,399.87	4.11	55.66	13.33	0.32

15.8 PATJ Pakistan- Tajikistan cross-border transmission link

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2020	40,577.36	40,638.08	60.72	94.63	58.76	1.03
2021	36,888.50	36,943.71	55.20	94.63	53.42	1.03
2022	38,373.72	38,428.74	55.02	94.63	48.56	1.13
2023	34,885.20	34,935.22	50.02	94.63	44.14	1.13
2024	31,713.81	31,759.29	45.47	94.63	40.13	1.13
2025	31,212.22	31,439.04	226.82	94.63	36.48	6.22
2026	28,374.74	28,580.95	206.20	94.63	33.17	6.22
2027	29,812.93	29,814.23	1.01	94.63	30.15	0.04
2028	27,102.66	27,103.85	0.92	94.63	27.41	0.04
2029	24,638.78	24,639.86	0.83	94.63	24.92	0.04
2030	22,398.90	22,399.87	0.76	94.63	22.65	0.04

15.9 IN12 India – Nepal

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2025	30,922.51	31,439.04	516.53	107.62	41.49	12.45
2026	28,111.37	28,580.95	469.57	107.62	37.72	12.45
2027	29,565.47	29,814.23	248.47	107.62	34.29	7.25
2028	26,877.70	27,103.85	225.88	107.62	31.17	7.25
2029	24,434.27	24,639.86	205.35	107.62	28.34	7.25
2030	22,212.97	22,399.87	186.68	107.62	25.76	7.25

15.10 IBABU India – Bhutan – Bangladesh

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2020	40,240.68	40,638.08	397.40	406.34	252.31	1.58
2021	36,582.44	36,943.71	361.27	406.34	229.37	1.58
2022	38,119.93	38,428.74	308.81	406.34	208.52	1.48
2023	34,654.48	34,935.22	280.74	406.34	189.56	1.48
2024	31,504.07	31,759.29	255.22	406.34	172.33	1.48
2025	30,765.67	31,439.04	673.37	406.34	156.66	4.30
2026	27,968.79	28,580.95	612.16	406.34	142.42	4.30
2027	29,466.01	29,814.23	347.93	406.34	129.47	2.69
2028	26,787.28	27,103.85	316.30	406.34	117.70	2.69
2029	24,352.07	24,639.86	287.55	406.34	107.00	2.69
2030	22,138.25	22,399.87	261.41	406.34	97.28	2.69

15.11 Bangladesh low load growth

15.11.1 IBA case

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2020	37,552.58	37,690.66	138.08	376.66	233.87	0.32
2021	34,138.71	34,264.24	125.53	376.66	212.61	0.32
2022	35,560.03	35,694.53	134.50	376.66	193.28	0.43
2023	32,327.30	32,449.57	122.27	376.66	175.71	0.43
2024	29,388.45	29,499.61	111.16	376.66	159.74	0.43
2025	28,512.75	28,778.66	265.91	376.66	145.22	1.80
2026	25,920.68	26,162.41	241.73	376.66	132.02	1.80
2027	27,329.48	27,537.34	207.85	376.66	120.01	1.71
2028	24,844.99	25,033.94	188.96	376.66	109.10	1.71
2029	22,586.35	22,758.13	171.78	376.66	99.19	1.71
2030	20,533.05	20,689.21	156.16	376.66	90.17	1.71

15.11.2 IBABU case

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2020	37,474.56	37,690.66	216.10	406.34	252.31	0.61
2021	34,067.78	34,264.24	196.45	406.34	229.37	0.61
2022	35,496.10	35,694.53	198.43	406.34	208.52	0.70
2023	32,269.18	32,449.57	180.39	406.34	189.56	0.70
2024	29,335.62	29,499.61	163.99	406.34	172.33	0.70
2025	28,440.63	28,778.66	338.02	406.34	156.66	1.91
2026	25,855.12	26,162.41	307.29	406.34	142.42	1.91
2027	27,277.82	27,537.34	259.52	406.34	129.47	1.76
2028	24,798.02	25,033.94	235.93	406.34	117.70	1.76
2029	22,543.65	22,758.13	214.48	406.34	107.00	1.76
2030	20,494.23	20,689.21	194.98	406.34	97.28	1.76

15.12 Utilization Improvement of the IBA Cross-border Transmission Link

15.12.1 Annuitized Costs - IBA – Upgraded

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2020	40,235.73	40,638.08	402.34	401.30	249.17	1.38
2021	36,577.94	36,943.71	365.77	401.30	226.52	1.38
2022	38,115.52	38,428.74	313.22	409.37	210.07	1.25
2023	34,650.47	34,935.22	284.74	409.37	190.97	1.25
2024	31,500.43	31,759.29	258.86	409.37	173.61	1.25
2025	30,887.55	31,439.04	551.49	457.59	176.42	4.38
2026	28,079.59	28,580.95	501.36	457.59	160.38	4.38
2027	29,473.75	29,814.23	340.48	462.60	147.40	2.61
2028	26,794.32	27,103.85	309.53	462.60	134.00	2.61
2029	24,358.47	24,639.86	281.39	462.60	121.82	2.61
2030	22,144.06	22,399.87	255.81	462.60	110.74	2.61

15.13 IBA Cross-border Transmission Link with Bareilly Terminal

15.13.1 Annuitized Costs - IBA – Bareilly

Period	Present worth of Annual cost ($ millions)	Present worth of Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2020	40320.27	40638.08	317.81	376.66	233.87	1.38
2021	36654.79	36943.71	288.92	376.66	212.61	1.38
2022	38187.80	38428.74	240.94	376.66	193.28	1.25
2023	34716.18	34935.22	219.03	376.66	175.71	1.25
2024	31560.17	31759.29	199.12	376.66	159.74	1.25
2025	30815.78	31439.04	623.26	376.66	145.22	4.38
2026	28014.35	28580.95	566.60	376.66	132.02	4.38
2027	29491.82	29814.23	322.41	376.66	120.01	2.61
2028	26810.74	27103.85	293.10	376.66	109.10	2.61
2029	24373.40	24639.86	266.46	376.66	99.19	2.61
2030	22157.64	22399.87	242.23	376.66	90.17	2.61

15.14 ISL Cross-border Transmission Link with High LNG Penetration in Sri Lanka

15.14.1 Annualized Costs - ISL India – Sri Lanka cross-border transmission link

Period	Annual cost ($ millions)	Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Annuitized project cost ($ millions)	Present worth of annuitized project cost ($ millions)	Yearly benefit cost ratio
2020	59,398.44	59,498.21	68.14	57.52	35.71	1.91
2021	59,398.44	59,498.21	61.95	57.52	32.47	1.91
2022	67,971.61	68,097.66	71.15	57.52	29.52	2.41
2023	67,971.61	68,097.66	64.68	57.52	26.83	2.41
2024	67,971.61	68,097.66	58.80	57.52	24.39	2.41
2025	73,591.77	74,135.44	230.57	57.52	22.18	10.40
2026	73,591.77	74,135.44	209.61	57.52	20.16	10.40
2027	85,057.02	85,070.61	4.76	57.52	18.33	0.26
2028	85,057.02	85,070.61	4.33	57.52	16.66	0.26
2029	85,057.02	85,070.61	3.94	57.52	15.15	0.26
2030	85,057.02	85,070.61	3.58	57.52	13.77	0.26

15.15 All Cross-border Transmission Links Connected

15.15.1 Annualized Costs – All Cross-border Transmission links Connected

Period	Present Worth Annual cost ($ millions)	Present Worth Base annual cost ($ millions)	Present worth of cost advantage ($ millions)	Present Worth Annuitized project cost ($ millions)	Present worth Net Benifit ($ millions)	Yearly benefit cost ratio
2025	30,334.84	31,439.04	1,104.20	293.05	811.15	3.768
2026	27,577.13	28,580.95	1,003.82	266.41	737.41	3.768
2027	29,173.51	29,814.23	640.72	242.19	398.53	2.646
2028	26,521.37	27,103.85	582.47	220.17	362.3	2.646
2029	24,110.34	24,639.86	529.52	200.15	329.36	2.646
2030	21,918.49	22,399.87	481.38	181.96	299.42	2.646

16 Appendix G – Transmission Cross-Border Capital Cost Estimations

Due to extreme changes in currencies and the suppliers being very busy, these costs could vary greatly. Thus the estimates are from open sources and adapted due to extensive experience. Most of the studied transmission projects do not have a well define route. Thus changes in the length of the line can produce large changes in the estimations. Table 16-1 gives the used values for the study.

Table 16-1: Estimated capital cost of cross-border transmission links

Project	IBU	IBA	IN1	IN2	ISL	IPA	AFPA	PATJ
Cost (Millions USD)	320	4 060	680	480	620	413	805	1020

Those values can be broken down as follow.

IBU: Rangia/Rowta (India) - Yangbari (Bhutan)

- Input data:
  - Technology: Double AC circuit
  - Voltage level: 400 kV
  - Length: 200 km
  - Rating 1 000 MW
- Cost estimation
  - 400 kV AC Sub-stations costs - $ 80 M USD
  - Double circuit 400 kV $ 1.2 M / km X 200 km = $ 240 M USD
  - Total = $ 320 M USD

IBA: Rangia/Rowta (India), Barapukuria (Bangladesh), North West India (Known location)

- Input data:
  - Technology: Three Terminals HVDC
  - Voltage level: +/- 800 kV
  - Length: 2300 km
  - Rating 6 000 MW with 500 or 1000 MW tap
- Cost estimation
  - Two 800 kV DC converter stations (6 000 MW) = $ 1 000 M USD
  - Third 800 kV DC Converter station 500 to 1000 MW = $ 300 M USD
  - 800 kV DC transmission line $ 1.1 M USD/km X 2 00 km = $ 2 760 M USD
  - Total = $ 4 060 M USD

IN1: Gorakhpur (India), Marsyangdi (Nepal)

- Input data:
  - Technology: Double AC circuit
  - Voltage level: 400 kV
  - Length: 500 km
  - Rating: 1 000 MW

- Cost estimation
    - 400 kV AC Sub-stations costs - $ 80 M USD
    - Double circuit 400 kV $ 1.2 M / km X 500 km = $ 600 M USD
    - Total = $ 680 M USD

IN2: Bareilly (India), Upper Karnali (Nepal)
- Input data:
    - Technology: Double AC circuit
    - Voltage level: 400 kV
    - Length: 400 km
    - Rating: 600 MW
- Cost estimation
    - 400 kV AC Sub-stations costs - $ 80 M USD
    - Double circuit 400 kV $ 1.0 M / km X 400 km = $ 400 M USD
    - Total = $ 480 M USD

ISL: Madurai (India), New Anuradhapura (Sri Lanka)
- Input data:
    - Technology: HVDC bipole (Assume VSC converter)
    - Voltage level: +/- 400 kV
    - Length: 350 km with 120 km of it undersea cable
    - Rating: 500 MW
- Cost estimation
    - Converter stations- $ 330 M USD
    - 400 kV HVDC Transmission line - $ 530 000 /km X 230 km = $ 122 M USD
    - 400 kV Under sea XLPE cables – $ 1.4 M USD /km X 120 = $ 168 M USD
    - Total = $ 620 M USD
    - Other sources estimation: $700 M USD

IPA: Amritsar (India), Lahore (Pakistan)

- Input data:
    - Technology: AC Quad double circuit, and back-to-back HVDC converter.
    - Voltage level: +/- 400 kV
    - Length: 60.6 km
    - Rating: 1000 MW
- Cost estimation
    - BtB HVDC - $ 260 M USD
    - 400 kV Substations - $ 80 M USD
    - 400 kV double circuit transmission line - $ 1.2 M USD X 60.6 km=$73 M USD
    - Total = $ 413 M USD

AFPA: Arghandi (Afghanistan), Peshawar (Pakistan)

- Input data:
    - Technology: Two terminal HVDC
    - Voltage level: +/- 500 kV
    - Length: 300 km

- Rating: 1000 MW
- Cost estimation
  - Converter stations - $ 320 M USD
  - HVDC transmission Line $ 933 000 USD/km X 300 km = $ 280 MUSD.
  - Total $ 600 M USD

PATJ: Rogun (Tajikistan), Peshawar (Pakistan)

- Input data:
  - Technology: HVDC bipole
  - Voltage level: +/- 500 kV
  - Length: 750 km
  - Rating: 1000 MW
- Cost estimation
  - Converter stations - $ 320 M USD
  - HVDC transmission Line $ 933 000 USD/km X 750 km = $ 700 MUSD.
  - Total $ 1 020 USD
  - Other sources estimation: $1 200 M USD

17 Appendix H - Cost of Operation Function and Terms Used For Each Technology

A linear cost of operation function is used such that, Cost = A + B*Pgen. 'A' is the fixed cost term (in $/h) and 'B' is the linear cost term (in $/MWh). 'Pgen' is the dispatched generation. Table 17-1 shows the terms of the cost function used.

Table 17-1: Terms of the cost function used for each technology.

Technology	A ($/h) Fixed term	B ($/MWh) Linear term
Hydro	35	4
Coal	27.2	38
Coal (India East)	27.2	20
Gas	15.7	70
Diesel	12.6	151.15
Nuclear	57.6	10.1
Wind/Solar	52.45	2.5
Import - Turkmenistan	0	60
Import - Uzbekistan	0	60
Import - Tajikistan (to Afg)	0	60
Import - Tajikistan (to Pak)	0	70

All cost coefficients except Coal are based on the World Bank cost of operation estimates for the region. Coal cost coefficients are based on the information gathered from the India authorities. Diesel cost terms are the average values for diesel based power plants and diesel fired gas turbines. Wind/Solar terms are also estimated based on the average of wind and solar cost terms.

18 Appendix I - Inclusion of new India – Bhutan and India – Nepal Cross-Border Transmission Lines

A cursory study was conducted by including a new India – Nepal cross border transmission link (IN3) and an additional circuit to the India – Bhutan (IBU) cross border transmission link. These modifications were included to the "All cross border transmission links interconnected" scenario for year 2027. The new India – Nepal transmission link is a 400 kV, 1000 MW line from Purnea (India) to Inaruwa (Nepal). A 3rd circuit (550 MW) is added to the proposed double circuit India – Bhutan transmission from Rangia/Rowta (India) to Yangbari (Bhutan).

This section demonstrates the results of the economic analysis of all cross border transmission links interconnected scenario with the IN3 link as well as the additional circuit of IBU link.

18.1 Cost of Operation

Table 18-1 presents the daily and annual costs of operation of "All cross border links connected with the new IBU and IN3 links" scenario for year 2027. These results are compared with the results of the original "All cross border links connected" scenario (detailed analysis in section 7.8) for year 2027.

Table 18-1: Daily and annual cost of operation with all the cross-border transmission links

Year (2027)	Daily cost of operation for the case ($ millions)				Annual cost ($ millions)
	Summer	Winter	Monsoon	Post-Monsoon	
All link case with new IBU & IN3	234.53	224.25	232.93	219.02	83,104.52
All link case	234.82	224.59	233.34	219.41	83, 234.60

The results indicate an annual cost of $ 83, 104.52 million which is slightly lower than the original case with all links.

Table 18-2 presents the cost advantage summary of this scenario for year 2027.

Table 18-2: Cost Advantage summary for the study period

Year	Cost ($ millions)		
	Cost of operation of base case	Cost of operation with All links including IBU and IN3	Cost Advantage
2027	85,063.48	83,104.52	1,958.96

18.2 Cross-border Transmission Link Power Transfer

Table 18-3 illustrates the utilization summary of the relevant cross-border transmission links upon connecting the new IN3 link and the 3rd circuit of IBU link.

Table 18-3: Capacity factor comparison of IN1, IN2, IN3, IBU and IBA cross-border transmission links

Average capacity factor (%)		
Cross Border Link	**All Links**	**2027-All links with IBU and IN3 Links**
IN1	89.5	100.0
IN2	99.4	99.9
IN3	N/A	99.7
IBU	76.2	45.7
IBA (BA-I)	61.6	59.5

Table 18-3 illustrates that IN3 link is fully utilized and the utilization of IN1 and IN2 links is slightly increased compared to the original "All cross border links connected" scenario. However, the utilization of IBU and IBA links is slightly reduced as the North India load is served mainly using India - Nepal transmission links. As the power evacuated from Nepal as well as Bhutan & North East India are mainly hydro, cost advantage in both cases are similar.

19 Appendix J - Review of Power System Planning

19.1 Introduction

The expansion of a power system is a complex activity, with its main goal to deliver electric power from new and retained generation sources to the future loads. The complexity comes from the amount of options and variables that have to be taken into account to make optimal power system planning decisions. Planning studies try to organize and quantify the most important variables to compare the possible options. There is not one single approach to find solutions, but it is a common practice to divide the problem into three main areas: load forecast, generating planning, and transmission planning. Another common practice is to classify the type of study by the time horizon: short term, medium term, and long term. These classifications help to reduce the difficulty associated with the planning problem and make the quantification of variables possible.

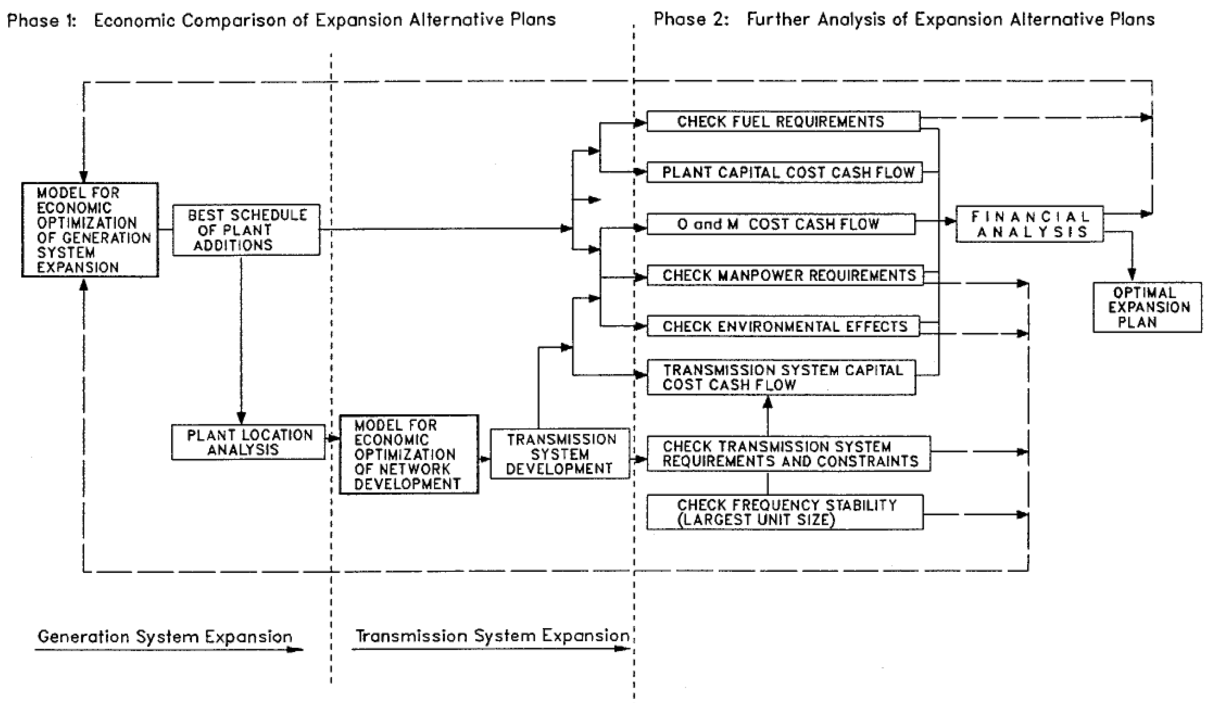


Figure 19-1: Schematic Representation of the Planning Process and Consideration of Constraints [1]

The purpose of this document is to review the current practices, study tools and mathematical techniques adopted for solving long-term power system planning problems.

This document discusses load forecasting, generation expansion planning (GEP), and transmission expansion planning (TEP). One method to address the problem is by using a scheme similar to the one depicted in Figure 19-1. Figure 19-1 shows two phases that have been defined by two types of constraints. The first phase includes constraints that can be included in a mathematical model. The second phase groups those that are more difficult to evaluate quantitatively or require special treatment (e.g. constraints that are not repeatable, and hence their values cannot be derived from the past such as social impacts, political decisions and utilization of reserved land).

The first phase divides the problem into two studies. The GEP tries to find the optimum group of power plants that have to be built to cover the forecasted load. GEP answers what to build (mix, technology, size, etc.), when to build, and where to locate those power plants. Once the mix of generation is finalized, the TEP should find the group of transmission equipment that it is necessary to build in the network to accommodate those power plants for successful power transfer to the load centers. Normally, the amount of options in this phase is so large that the exploration of all the possible options could be unreasonably expensive in computational terms. After solving GEP and the TEP, there will be a set of technical solutions, which are 'optimal' from the economical point of view.

While the optimization process includes many engineering constraints that have been modeled, the optimum economic solution does not assure that the solution is technically feasible. In addition, one also faces voltage and transient stability problems that have to be studied in detail before reaching the final decision. Moreover, the economical optimum can be impossible to achieve without a proper financial plan. All of these and other constraints, such the availability of infrastructure (roads and trains to carry materials) or professionals to build the project, have to be evaluated after the first study phase is finished. The main reason to split the planning process is due to the fact that checking all aspects for each possibility would increase the evaluation effort exponentially. Thus, only selected solutions of the economical optimization are checked against these other constraints.

Finally, finding the optimum power system expansion plan depends on the industry framework that the plan is a part of. It is possible to talk about vertically-integrated businesses, such as monopolies, or competitive systems, such as different types of liberalized markets. Every environment has different characteristics and goals. Hence, reliability, environmental impact, or investment risk could potentially be aspects that have to be included as terms in objective functions or constraints in the optimization process.

19.2 Load Forecast

The starting point in the power system planning is to estimate the future electric load demand. A diagram of how the process is usually done is shown in Figure 19-2. The load forecast process starts with the collection of historical data. The two boxes on the left hand side show the two dimensions of the problem. The spatial forecast refers to the amount of power that is expected to be consumed in a region. It is usual practice to divide the region of interest into areas [2]. The consumptions for all the loads of each area are aggregated (i.e. an area is the smallest geographic unit that is considered in the next steps of the analysis), as it is shown on the middle box of Figure 19-2 (Time forecast). The amount of consumption data required depends on the granularity of the time forecast. Usually, an hour-by-hour data is used for short-term forecast (operation planning). If the same granularity is used in the mid-term or long-term forecast, the amount of data would make the problem difficult to manage. Moreover, it is unnecessary to estimate the load hour-by-hour for a study, where time horizon is in the range of years. The amount and magnitude of the uncertainties that arise diminishes the value of such quantification. The way to manage this situation is to use the peak values for the year, because they represent worst case scenarios with risk of not delivering energy to the loads. In the case of a long-term forecast, two or three values per year can be a good compromise between the amount of data required and accuracy [3]. Load growth is influenced by parameters such as population growth and GDP. A list of some of the most important driving parameters is shown in the Figure 19-2. Using these driving parameters, it is possible to use mathematical tools to make an estimation of the loads [3]. Some of the most popular tools are econometric models, end-use analysis, curve fitting, and auto regressive moving average [4-6].

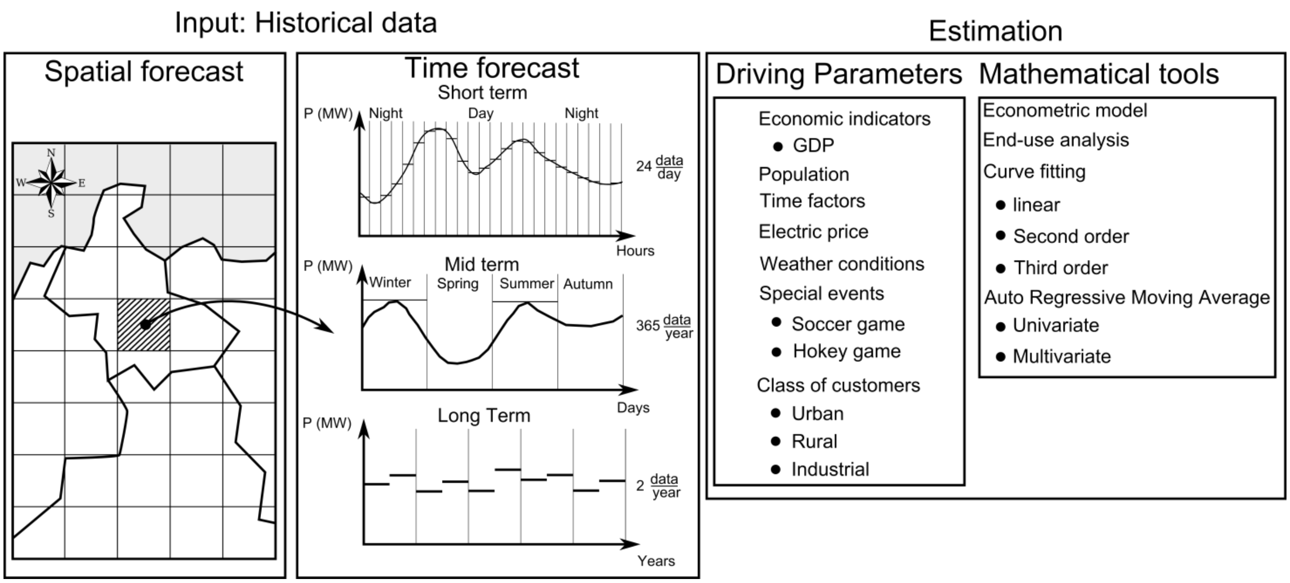


Figure 19-2: Scheme with Different Aspects of the Load Forecast Process

19.3 Generation Expansion Planning (GEP)

GEP is the process of finding optimum solutions (a set of power plants) for covering the future load demand. The solutions have to answer the questions of "what", "where", and "when". "What" means the specification of the mix of technologies that has to be used (thermal, hydro, nuclear, etc.), and the size of each unit. "Where" refers to the geographical location of the power plant, and "when" means the year in which the power plant should be in service. The GEP solutions are limited by many constraints, such as reliability level, availability of resources and environmental considerations.

The GEP has to be formulated based on the regulatory framework, in which the power system is developed. See Section 0 for further discussion. Once the framework is defined, and the main driving parameters have been identified, a model is built. There are two main approaches to build the model [7]. The simplest model assumes that all generation is concentrated in one bus, and all loads are connected to that bus. The single-bus GEP does not give information about where to build the power plants. The multi-bus generation expansion planning helps to remove some of the assumptions by taking into account the network and the buses where the generators can be connected. A procedure similar to one depicted in Figure 19-3 can be used to find the optimal solution for GEP.

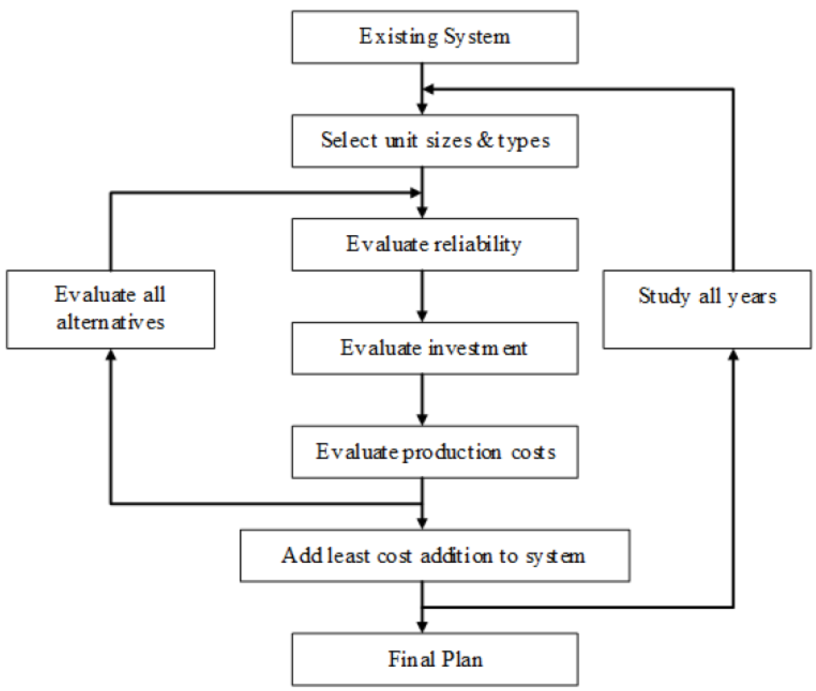


Figure 19-3: Example of GEP Procedure [8]

The following sections describe the most important aspects of the generating expansion planning problem, and different approaches used in industry.

19.3.1 Technology Options

The computational time to find the optimal solution of the GEP depends of the number of power plants that are taken into account. For this reason, it is critical to classify and define the available options. Moreover, the long-term planning should also account for future technologies that will become available in the period of study. A traditional list of options is shown in Table 19-1. The availability and cost of the fuel in the region is critical for deciding if a specific technology has to be taken into account. This aspect is clear in case of wind and solar energy, because their prime movers are intermittent. Hence, those types of power plants cannot be considered as independent generating sources [9] and usually an amount of open combustion or combined cycle power plant has to be built to secure load demand.

Table 19-1: General Classification of Available Power Plant Technologies

Type power plant	Prime mover
Nuclear	Uranium
Fossil thermal	Coal
	Oil
	Natural gas
Open combustion	Diesel / Natural gas
Combined cycle	Natural gas
Hydro	Water
Tidal	Water
Ocean thermal	Temperature difference
Wind turbine	Wind
Photovoltaic	Sun
Thermal solar	Sun
Fuel cell	Hydrogen
Geothermal	Temperature difference

19.3.2 Reliability

There are several constraints which are common to the GEP and TEP, as is explained in Section 6.2. However, special attention must be paid to reliability, because it is modeled differently for each problem (that is GEP and TEP).

The generation planner should have a method of measuring the reliability of the proposed solutions. This aspect is fundamental in a liberalized market, in which the reliability can go against the economic profit. The usual practice for the GEP is to use indices, whose values define technical constraints during the optimization process to guarantee reliability levels. The approach is to have a measurement of how the generators are going to cover the load demand independently of the network. However, there are models that take into account the transmission system to some level. A list and a short description of the most important reliability indices are provided in Table 19-2 [10], [11].

Table 19-2: Most Common Reliability Indices in GEP

Index name	Type	Description
Reserve margin (RM)	Deterministic	It measures the generating capacity available over and above the amount required to meet the system load requirements ((Total available generating system capacity – peak system load)/peak system load).
Largest unit (LU)	Deterministic	It compares the total installed generating capacity less the peak system load with the largest installed units on the system ((total installed generating capacity – peak system load)/largest unit capacity).
Dry year	Deterministic	It is the required energy supply during the driest year of the available statistical information or a year related to a certain cumulative probability.
Loss of load probability (LOLP)	Probabilistic	It is the probability that some portion of the load will not be satisfied by the available generating capacity. It is measured ratios of time (days/year or hours/year).
Probability of positive margin (POPM)	Probabilistic	It is the LOLP for only the peak hour of the year.
Expected Unserved Energy (EUE)	Probabilistic	It measures the expected amount of energy that will not be supplied per year owing to generating capacity deficiencies and/or shortages in basis energy supplies.
Loss of energy probability (LOEP)	Probabilistic	It is the ratio of the expected amount of energy curtailed owing to deficiencies in the available generating capacity to the total energy required for the system.
Expected loss of load (XLOL)	Probabilistic	It indicates the expected magnitude of the unsupplied load, in MW, given that a failure has occurred.

19.3.3 Planning Methods

A method for solving the GEP problem is determined by input data (load structure and technology options), an economic model (equations which represent objective function and constraints), and an optimization algorithm (Section 6.3). As mentioned at the beginning of this section, it is possible to identify two methods for solving the GEP. This sub-section describes briefly each one.

19.3.3.1 Single Bus GEP

This method simplifies the problem by making some assumptions, including that the transmission system strength is infinite, the fuel and land cost are independent of the location, population density restrictions do not exist (nuclear power plants have this kind of constraint), land availability (hydro project dams require considerable amount of space), social and environmental acceptance is assured -. The model built based on this method will not adequately answer the question: where to build the group of power plants that are the solution of the GEP problem to the extent they are not captured in feasibility analyses. The output only says what technologies would be more economical and when they should commissioned.

Since the transmission network is not modeled, the computational effort is reduced significantly, because one does not require running any power flow cases to find the solution to the GEP problem.

The method starts by defining an objective function, which usually includes terms such as investment cost, fuel cost, operation and maintenance cost, and value of energy not served. The second step is to define technical constraints, such as fuel, pollution, or reliability (the reliability constraint is defined using an index of Table 19-2), etc. In the following steps, the algorithm evaluates the objective function to find the optimum. The output is the mix of technologies to be built, which minimizes the cost or maximizes the goals of the objective function. Dynamic programming based algorithms can also answer when each generation group of the optimal solution has to be commissioned.

Examples of GEP models which use this method are WASP-IV [12], EGEAS [13], or STRATEGIST [14]. More details about models are discussed in Section 0.

19.3.3.2 Multi-Bus GEP

This method can be considered the second part of GEP, if the single bus method has been used to find what and when to build. The goal is to distribute the generators among the buses in such a way that transmission enhancement requirements are minimized [7]. Including transmission constraints makes the problem/solution space large and complex.

The location of a new generator on a bus can produce overload in lines, voltage problems, or instability in the network. It would be very ambitious to examine all those problems for each possible combination. For this reason, the multi-bus GEP usually only tests the overload constraint. Identifying overloads requires at least one power flow evaluation for each possible combination. Knowing the number of runs is a permutation problem, in which number of buses is the number of objects to choose from, and the mix of generators is the number of objects to be chosen. This number can be very high. One method to reduce the computational time is to use a simplified model of the network and a 'fast' power flow algorithm. The common practice is to use a DC (de coupled) power flow algorithm [15] to make each power flow calculation fast, and an optimization algorithm, such as linear programming, to practically manage the optimization process. Examples of models which use this approach are PLEXOS [16] and NATGRID [17], and GTMax [18].

19.4 Transmission Expansion Planning (TEP)

TEP tries to find the optimum economic routes between the generation and the loads, securing that the loads are supplied completely during normal and contingency operation. Economic optimum means that the objective function is defined by economic terms (investment, cost of operation, etc.) of all the power transmission projects that fulfill the constraints. Finding the minimum cost is a task for an optimization algorithm (e.g. linear programming, heuristic methods, etc.). Contingency operation means that the optimum plan should be able to deliver power to the load, under single or multiple device outages. This reliability criterion, which is defined by the planner, has a strong influence on the computational effort to find the optimum solution, as it is shown in the next section. Several methods are available to find the optimum, but all of them have similar components. The procedure starts with defining the economic objective function and grouping in project sets which are potential solutions. The optimization method evaluates the objective function and checks the reliability criterion by running a power flow algorithm several times within the optimization process. The final decision is the set which does not violate the reliability criterion and has the lowest power system expansion cost. A general scheme of this process is depicted in Figure 19-4.

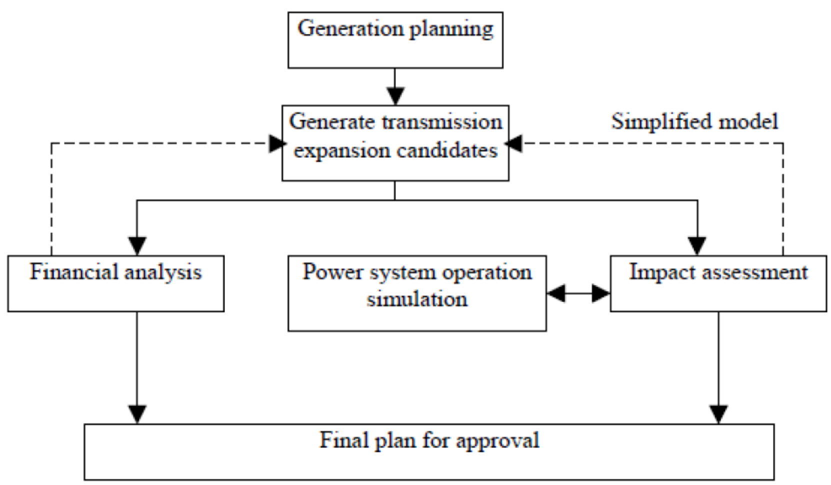


Figure 19-4: TEP procedure from [19]

19.4.1 Reliability

The reliability criterion in TEP is linked with the concept of outage. It is common practice to establish the N-1 criteria, which means that taking the normal operation case (N), and removing one element (-1) the power system should supply all loads without violating thermal capacity of any other element, and maintain voltage at all the buses within technical limits. An element can be a power line, a transformer, or a generator. Hence, for each outage or contingency, the power flow algorithm should be run once. If one defines the existing lines as N, the set of candidate corridors as M, and the number of feasible lines per corridor as K, the number of possible topologies or cases is (K+1)^M. The total average number of load flows is (k+1)^M (1 + N + (K M / K + 1) [7]. These equations show how the size of the problem increases with the size of the network. Planners can define their reliability criteria as N-2 or N-3, which can make the computation practically impossible in a big system.

19.4.2 Planning Methods

This section classifies some methods to tackle the TEP problem. The selection of the method depends on the size of the problem (i.e. number of corridors to be assessed). As per the description in the previous section, it is clear that the TEP can potentially generate a huge amount of cases. Thus, practical methods are designed to provide an efficient strategy to reduce the number of power flow runs.

19.4.2.1 Enumeration Method

The obvious way to find the best solution is to check all options. If the network size is small or if the feasible transmission corridors have been reduced to a small number without the application of engineering constraints, it would be possible to check the reliability criteria for each option. The economic evaluation is done for the group of corridors that fulfill the reliability constraint (e.g. N-1 criteria). The final plan is the one that has the minimum cost or the maximum profit, if the objective function is defined for markets.

19.4.2.2 Heuristic Methods

These methods refer to rules and techniques which are practical for finding a local optimum, but they do not assure to get the global optimum. Although there are mathematic formulations for heuristic algorithms, they are basically exploratory techniques to scan the solution space in an intelligent way.

19.4.2.3 Forward Method

The method starts by calculating the cost of all candidate lines and organizing them from the least to the most costly. Another way to start is to organize the future projects in accordance with impact on congestion removal using engineering judgment. Then, taking the original network in which there are no new power lines, the line with the minimum cost or the line which promises better performance is added to the network. The reliability criterion (N-1) is applied to the new case. . Frequently, the forward method starts from a case in which the power flow violates the technical constraints (e.g. overload, voltage drop, etc.) in both normal and N-1 conditions. Other new cases are built by adding candidates one by one, and the objective function is evaluated for these new cases. Their reliabilities are checked. The case that improves the value of the objective function is selected for the next step. The process continues until the network operates properly in normal and N-1 conditions. Therefore, the solution is a set of power line projects that result in the system operating properly. However, as it has been mentioned, one may not be sure that there is not another less costly set which fulfill the N-1 criteria. The reason is that the method does not evaluate the whole candidate space, and the list cannot guarantee a path to the global minimum.

19.4.2.4 Backwards Method

This method starts by adding all new power line projects to the network. Following that, the N-1 analysis is applied. Usually this new case does not produce an overload or violate any technical constraint. If it does, it is necessary to use some engineering analysis to identify which other power lines should be added or which ones can be removed to work in the space of solutions that fulfill these requirements. The next step is to remove the power lines one-by-one and evaluate the objective function for each new generated case. For example, if there are ten candidates, ten new cases are generated, in which only one line has been removed. The project that improves the objective function value is selected, and the rest are rejected. The N-1 criteria are checked for this case. This method finishes when all the new generated cases do not operate properly in N-1 conditions. The solution is the project set of the previous iteration that had the best objective function value.

Generally, the backward method has more computational effort than the forward method. The solution also has a higher number of power lines; however, the cost is less, because the most costly projects are removed first. This is contrary to the forward method, in which the most effective lines are added first, and usually have higher cost.

19.4.2.5 Decrease Method

In this method, the term “decrease” means a decrement in the power delivery capacity of a corridor assuming that that a corridor can have different capacity levels (e.g. single circuit, double circuit, triple, etc.). The method can be applied in combination to the backward or forward method. The difference is that the candidates are corridors, and the maximum capacity is always chosen at the beginning. In a second step, a decrement in the capacity is applied to improve the objective function value (cost), and it is checked if the case violates the reliability criteria.

19.4.2.6 Backward-Forward-Decrease Method

The objective of this method is to reduce the computational effort of the backward method and to reduce the number of candidates in the forward method when the network is large. The first step is to apply the backward method using only normal operation conditions to check if the case is valid. Then, apply forward checking the N-1 criteria. This stage finishes when the solution has defined the corridors that optimize the objective function. Finally, the decrease method can be applied to know if a reduction in the corridor capacity improves the solution.

19.4.3 Load Flow

Last sections show that the TEP needs to run a power flow algorithm many times to check the technical constraints. The power flow algorithm has a strong influence in the computational effort of finding the optimum and the accuracy. This last aspect is frequently sacrificed to some extent during the optimization process, as making a very detailed simulation of each case could result in the problem being unapproachable. Many authors have proposed simplifications of the actual algorithm to find solutions faster. They expect that the optimum solution obtained will be tested with more accurate power flow to find technical problems that could be hidden by the simplifications. Another aspect is that data, such load and generation, have uncertainties that can make the final plan too pessimistic and costly because of conservative assumptions dominating those inputs. Using a statistical approach in combination with the power flow algorithm can help to relax that influence without increasing the risk significantly. The following sections explain some of the most common modifications in the power flow algorithm.

19.4.3.1 Direct Current Load Flow (DCLF)

DCLF is resorted to because active power has significantly more influence in the planning problem than reactive power. Therefore, it is possible to neglect the power flow formulation equations that are related to the reactive power. This point seems reasonable, because the objective of the network is to be efficient in transporting useful energy (active power). The reactive power in this case could be considered an unavoidable inefficiency. The second simplification is linearization of the active power related equations. This is done by neglecting power line resistance , assuming that the voltage angle differences between buses are small and the network presents flat profile (voltage equal to one per unit in all buses), and ignoring transformer tap changers. Thereby the final equations have only two types of variables: active powers and voltage angles. Comparing algorithms, the original alternating current load flow algorithm, and DCLF, DCLF has advantages. Specifically, it is not an iterative solution; it is computational faster and always converges. On the other hand, the accuracy is diminished, and in some cases DCLF solutions are not acceptable as real solutions.

19.4.3.2 Generalized Network Flow Model

This model is formulated using mechanical simile [20]. The generation nodes pump a fluid that flows in pipes towards sinks (consumption nodes). Each pipe has a delivering capacity, which cannot be overflowed, and an associated cost. This model fits the Kirchhoff current laws, but not Kirchhoff voltage laws (KVL), when it is applied to electric networks. It is possible to include the KVL as a least-effort criterion for each pipe. If some linear constraints are added, this model is equal to DCLF [21].

19.4.3.3 Probabilistic Load Flow

This method uses the ordinary load flow formulation, with the main difference that loads are modeled using probability density functions. The probabilistic load flow can be considered a method to improve reflection of diversity, but it increases the computational burden significantly. In order to get the results, it is necessary to run a Monte Carlo simulation of the original network [22] [23]. The outputs are the probability density functions for each line of having an overload or outage. Using one of the methods described in Section 5.2, several expansion plans are selected. A Monte Carlo simulation is run for each plan. The output probability density functions of each case are compared, and a plan is selected using technical criteria and economic analysis.

19.5 Economic Analysis

It is possible to define different objective functions for GEP or TEP, as it has been enumerated in the introduction, but all of them are described in economic terms. Optimizing the objective function requires o minimizing or maximizing the monetary value over the time frame for which the study has been designed for. Capital costs have to be distributed over the life span of the projects. Power plant maintenance and the fuel costs are required after commissioning. These costs have to be discounted over the planning period (sometimes longer than 20 years) to reflect the time value of money.

The following sections enumerate and describe the components considered for design of the economic model. The first section is about common economic variables that comprise the objective function. The second section explains the constraints, and the last gives a list of popular optimization algorithms to find the economic optimum.

19.5.1 Economic Variables

The objective of power system planning depends on the context in which the business is developed, but the most important aspects of the business should be captured in the mathematical expressions.

Table 19-3 shows the most important variables which are captured in the GEP or TEP objective functions with a short description of them.

Table 19-3: Economic Variables for GEP and TEP

Economic variable	Description
Capital investment cost	It is the cost associated with the construction of the project. Some of the concepts that are included in this variable are the cost of the land or right of way, the materials, the machinery, the construction force, etc. It is usually expressed in monetary units per MW.
Salvage value of investment costs	This is the value of the project at the end of its useful life. Since after the power plant has finished its life, the land and equipment have some value, which the investors can recover.
Fuel cost	This cost is linked with fuel consumption, price of the fuel, its transport cost, and the infrastructure cost to make it available to the power plant.
Operation and maintenance cost	This cost accounts for nonfuel related expenditures, such as operating, maintenance and management costs.
Upgrading cost	This is cost related to upgrading current infrastructure, e.g. upgrading of a power line can be a more profitable solution than to building a new one.
Cost of energy not served	This is the cost of energy that has not been produced or delivered, because the generation plants or the power lines have suffered unexpected outages.

19.5.2 Constraints

The amount of possible options is more than the amount of feasible solutions in the power system planning calculation. It is possible to enumerate several factors that determine if one option is feasible to implement. Table 19-4 shows a classification of several constraints that can be used to limit the solution space.

Table 19-4: List of Factors which can be used to Model Constraints

Technical constraints		**Non-technical**
Generating unit	**Transmission**	
Frequency stability	Short-circuit levels	Environmental impact
System reserve requirements	Thermal ratings	Infrastructure needed
Maintenance requirements	Transient stability limits	Manpower and training requirements
Grid interactions	Reliability	Fuel requirements
Load characteristics		Availability of funds
Reliability		Regulatory acts
		Social factors
		National policies

The constraints impose limits that cannot be violated, because there is no possible technical solution (e.g. big power plant that has to connect and disconnect instantaneously to avoid instability) or the solution will affect other aspect which are justified outside the power engineering scope (e.g. protected natural park where it is not possible to build any infrastructure).

The challenge for the planner is to translate those constrains in mathematical equations that can be included in the optimization process. Many of these constraints can be implemented in the mathematical model to be optimized using arbitrary variables.

On the other hand considerations such as social factors are very challenging to implement in mathematical models. Unrealistic constraints have the potential to change the economic value of variables drastically, making the final solution useless. If it is not possible to reduce the uncertainties or include such constraints in the economic model, engineering judgment is necessary to validate the output from mathematical models. In essence it is important to ensure that the mathematical optimum is practical and feasible.

19.5.3 Optimization Algorithms

Minimizing the cost or maximizing the profit is the objective of planning. Finding the optimum can be a time-consuming and complex task. That is why it is possible to find a long list of algorithms that try to accomplish the objective in an efficient way. There are two main groups of algorithms: mathematical algorithms and heuristic methods. Examples of mathematical algorithms are linear programming [25], integer programming, mixed integer linear programming [26], Benders' decomposition [27], dynamic programming [28], nonlinear programming, and others. Examples of heuristic methods are genetic algorithm [29], simulated annealing [30], particle swarm [31], ant colony, expert systems, fuzzy sets

[32], and others. This section emphasizes those which are more frequently named in the power system expansion planning area.

19.5.3.1 Dynamic Programming

This algorithm is in the core of many commercial models. Dynamic programming has a long history of being used in many practical cases especially for GEP [12], [13]. It is easy to adapt to answer when the project should be commissioned. The algorithm divides the period of interest in stages (years). Each stage has a group of feasible states (mix of potential generation units or transmission line that could be commissioned that year with constraints honored). The optimum solution is the sequence of states which minimize the cost for all the stages together. The algorithm starts from a fixed state and evaluate the optimum solution for the following state until the final stage is reached. Essentially, the algorithm subdivides the global problem into sub-problems and finds the optimum for each one. However, constraints must be used to limit the number of possible states since the number of possible states can rapidly increase as the study period increases. Also, a buffer period beyond the final stage can be provided to reduce the algorithm trend to select less costly options towards the end of the study period.

19.5.3.2 Linear, Linear Mixed-integer, and Non-linear Programming

What algorithm can be applied to an optimization problem, such GEP and TEP, depends of how it is formulated. That is, why the problem has to be classified before an algorithm can be applied. There are two critical aspects: the nature of the variables and how they are related. If the problem can be formulated with continuous variables, and all equations are linear, linear programming is required. If the variables are a mix of discrete (integer variables) and continuous (real variables), the problem is a mixed-integer programming problem. If the objective function and or the constraints have non-linear terms, the problem goes into the category of non-linear programming. There are many successful examples, in which the GEP and TEP have been formulated as linear programming problems. The challenges come from the need to linearize the equations and incorporate random nature in the variables, and the number of discrete variables that can be included in the model. This last point increases the computational cost significantly. One way to limit the number of discrete variables is to model them as real variable and then round them to the nearest integer (e.g. number of generating units).

19.5.3.3 Heuristic Algorithms

These algorithms are versatile tools, which can tackle problems for which mathematical formulations, such as dynamic programming or linear programming, cannot be applied. In fact, mathematical-based algorithms seek an optimal solution, but they do not guarantee to find the global optimum. Therefore, if the problem is very complex, its formulation does not fit into the assumptions of mathematical formulations. When the lack of ability to find the global optimum poses a major economic disadvantage, heuristic algorithms should be used. They are not the final solution to the optimization problem. They also do not guarantee to find the global optimum or an estimation of how far it is, but their characteristics allow finding good solutions in short times for a large variety of complex problems. They have been successfully tested in practical problems, and they continue being the focus of intensive research. No commercial models have been found that use this type of algorithm. Examples of heuristic algorithms are genetic algorithm, simulated annealing, particle swarm or ant colony, and others.

19.6 Generation and Transmission Planning Models

The combination of objective functions, constraints, and algorithms is called a model in power system planning. The first models were developed to solve the GEP using the single bus approach. Some of those models have evolved to include the transmission system to improve the accuracy, and how the reliability of the system is calculated. Power flow equations (as they were described in Section 5.3) are included in those models, but they are not designed to solve the TEP. However, they can be useful for that purpose, if the models are used in combination with some of the methods discussed in Section 19.5.2. Table 19-5 shows a list of commercial models with some of their characteristics.

Table 19-5: List of Commercial Models for Power System Planning. T = Transmission, G*= Generation*

Package	Ref	Name	Developme nt	T*	G*	Reliability evaluation	Algorithm
WASP-IV	[12]	Wien Automati on System Planning Package	International Atomic Energy Agency	No	Yes		Forward dynamic programming
EGEAS	[13]	Electric Generatio n Expansio n Analysis System	Electric Power Research Institute	No	Yes	Monte Carlo	Linear programming, Generalized benders decomposition and dynamic programming
PLEXOS	[16]		Energy Exemplar	Yes	Yes	Monte Carlo	Mix Integer linear programming
STRATEGIST	[14]		Ventyx	No	Yes	Monte Carlo	Dynamic programming
MNI	[1] [32]	Modèle National d'Investis sement	Electricité de France	No	Yes		Optimal control theory
CERES	[33]	Capacity Expansio n and Reliability Evaluatio n System	Ohio State University	No	Yes		Dynamic programming
NATGRID	[17]	National Grid	Indira Gandhi Institute of Development Research	YES	Yes		Linear programming

19.7 Regulatory Processes

During the last two decades, many countries have started the transition from vertical integrated companies to a competitive environment in the power industry. The main reason for that transition is a promise in reducing the cost of electricity [36]. The governments that have decided to introduce competition in their regions have established several economic markets, which try to facilitate the economic trade of products (e.g. energy, CO_2, etc.), and services (e.g. right of transmission, ancillary services, etc.), while ensuring secure operation of the power system.

Power system expansion planning has to be formulated within the regulatory framework in which the power system is developed. In case of a vertically-integrated and regulated industry, like a monopoly, the main goal is to minimize the investment cost of the future power plants, taking the reliability as the most important aspect. In a free market, the objective function changes to maximize profit. Such profit can include social surplus, environmental benefits (e.g. reduction of gas emissions), and congestion management.

It is difficult to classify the electric markets that are running in the world, because many of them have evolved from theoretical concepts to more practical implementations to avoid failures [3]. A general classification can be based on the type of product or service that is negotiated. It is possible to find energy markets, ancillary services markets, transmission markets, and CO_2 emission markets. All electricity markets are forward markets, and have several temporal windows. It is frequent to talk about day ahead, hour ahead and real time market for the energy market. In transmission markets the different types of rights (right to transfer, right to inject, and right to extract power) are usually traded in the annual, monthly, weekly, or day windows. Referring to how the markets operate can be classified as bilateral contracts, marginal auction, or discriminatory auction.

Establishing competition has tended to split the traditional electric company into different businesses, and to define roles for each activity in the market. Entities that can be found are the independent transmission operator (ISO), generation companies (GENCOs), transmission companies (TRANSCOs), distribution companies (DISCOs), retail companies, aggregators, brokers, etc. Usually it is the government and ISO, which, by means of rules and laws, control the rights and duties of the other entities to unsure that they do not have market power to artificially modify the price.

The success of a competitive electric market depends on ensuring fair, neutral, and robust price discovery, providing extensive and quick price dissemination, designing standardized contracts, and working towards increasing liquidity in such contracts.

From the point of view of TEP and GEP, liberalization of the power system business tends to reduce generation investment (avoiding over capacity), improve the technological mix of generation (more green technologies), and increase efficiency and utilization of the transmission network.

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20 Appendix K - Assumptions

20.1 General

The accuracy of the study results depends on the availability of accurate data and the assumptions that are made to address the missing data. Significant effort was required for the process of gathering the information. Some of these difficulties are due to the size of the studied systems and uncertainty introduced when dealing with a study period up to 2030. Also, the data had to be collected from different sources in the respective countries. Collected data have come from many sources such as discussions with experts from the different countries, provided PSS/E™ cases, reports and publications in the public domain, etc. Despite the efforts, the above factors have made the task of preparing a complete database a difficult undertaking. Following sections discuss the gaps in the data and the assumptions made following the data gaps.

20.2 Assumptions

- Load forecast
    - For each country, the future geographic load distribution during the peak period is obtained from the given simulation (PSS/E™) cases and uniformly scaling the peak load. The scaling factor is selected based on the load forecast (given in planning reports) for the specific year.
    - In the case of India, future load demand in the simulation case is scaled based on the load forecast of each region. Each region has different load scaling factor.
    - The load forecasts in Bhutan for years beyond 2022 are not available therefore existing forecast data are extrapolated to obtain the forecast for 2020-2030 period.

- Daily load data assumptions
    - Four different seasons (summer, winter, monsoon and post monsoon) are selected to represent the variation of the load during a single year.
    - Simulation cases to represent each season are derived by scaling the peak load of daily load curve for a given season.
    - Daily load variations are derived by scaling the load according the daily curve of each season.
    - The single daily load curve available for Pakistan and Sri Lanka are used throughout the seasons.

- Generation assumptions
    - All the generators that are connected to the same PSS/E™ bus are aggregated as a single generator as they belong to the same plant.
    - If the generation limits Pmax and Pmin shows unrealistic values in the PSS/E™ case such Pmax = 9999.9 the limits were changed as follows:
        - If Pmax is unrealistic the value is changed to its Mbase when it is available.
        - If Pmin is less than zero Pmin is set to zero.

- If the technology of the generator is unknown, typical values are used for their cost of operation function and ramping rates.
- If the availability factors are unknown for a country, availability factors of the closest Indian region are used. If these values are too low to achieve power balance, they are suitably modified.
- Typical values for the cost of operation function of the generation are assumed based on the type of energy source and rating of the power plant.
- As the ramp rates of the generators are not known, typical values are assumed based on the type of technology and rating.

- Transmission assumptions
  - If the transmission line parameters are not given they are assumed based on similar lines in the system.
  - The transmission system for Bangladesh in 2027 is based on the 2022 PSS/E™ with augmentation.
  - The transmission system in India for 2022 case is derived using 2027 PSS/E™ case by removing a set of transmission lines to be commissioned after 2022.
  - The transmission system for Bhutan has been modelled using the India PSS/E™ cases.
  - The transmission system of Sri Lanka for the year 2022 and 2027 are based on its 2021 PSS/E™ case and 2026 PSS/E™ case, respectively.
  - The transmission capabilities of all low voltage branches (lines or transformers) are increased to neglect their thermal constraints during the optimization process. Thermal constraints of the branches connected to following voltage levels are considered in the study:
    - 400 kV and higher for India with the exception of the North-East region. As the 400 kV network in North-East India is smaller compared to the other regions, 220 kV network is also considered.
    - 220 kV and higher for Bangladesh, Bhutan, and Nepal
    - 132 kV and higher for Sri Lanka
  - The branches in the PSS/E™ cases where thermal limits are not specified are assumed to have a high thermal limit in the economic model to exclude their thermal constraints during the optimization process.
  - The transmission penalty factors (soft thermal limits) have been estimated in a way that only a small amount of transmission branch parameters have to be modified to make the cases feasible.

21 Appendix L - Bibliography List

Numbe r	Source name	Type	Remarks
1	Central Electricity Authority http://www.cea.nic.in/welcome1.html http://www.cea.nic.in/monthly_power_sup.html	Web site	They publish a monthly report in which peak demand, peak met and energy are included.
2	TRANS-FINAL.pdf (National Electricity plan- Volume-II.)	Report	Chapter eight has a description of some expected interconnections between the Nepal and Bhutan with India. The document has also a good description of interconnection project between states.
3	IND states.pdf	Report	There are some hand written corrections to include the new state of Telangana (2014)
4	Gen final merged.pdf (National Electricity plan Volumen 1)	Report	The report is a general description of the type and size of power plants which will be necessary to build during the studied period. They have used EGEAS for doing the study.
5	EPS_118th_Load_Factors.pdf	Report	It is a table with the estimated load factor values for the plans 12th and 13th
6	pn 12 plan GENRN LIST _13 sep14_r1.xlsx	Report	It is an excel file with a list of 558 generators
7	Generation_projects-future.xls	Report	It is an excel file with the power plant which are planned to build in the plans 12th and 13th
8	India ge.xlsx	Report	It is an excel file with the generation forecast. The forecast is for the last year of each plan from 2016 to 2031. It differentiates by type of fuel (Coal,Gas, Nuclear and Hydro) and by state. Measurements

			are in GW.
9	India – Load.xlsx	Report	It is an excel file with the load forecast. The forecast is for the last year of each plan from 2016 to 2031. The data shows the state-wide net energy for the load in GWh.
10	IND NEW_Basic_Netwrk_2013-2014_q1.raw	Simulation case	This is PSS-E case which represents the Indian power system for 2014. It has data for the generation, load and transmission system for the year 2014. It can help to identify the new infrastructure in other cases.
11	Alfile.sav	Simulation case	It has data for the generation, load and transmission system. This case is the same as Alfile_2017Peak.sav
12	Alfile_2017Peak.sav	Simulation case	This is PSS-E case which represents the Indian power system. It has data for the generation, load and transmission system for 2017 scenario.
13	All_India_2027_Case_Ver_33.sav	Simulation case	This is PSS-E case which represents the Indian power system for 2027.
14	Base 2020.sav	Simulation case	This is PSS-E case which represents the Indian power system for 2020.
15	Base 2030.sav	Simulation case	This is PSS-E case which represents the Indian power system for 2030.
16	Duration_curve_seasonal_updated.ppt	Report	This a power point presentation with duration curves in India for different months in 2014 and 2015.
17	JTT revised_20March 2014 incl bdesh comments.pdf	Report	This is a review of a study to increase the number of links

			between India and Bangladesh. This document presents and evaluates three different alternatives to build transmission projects between both countries.
18	Indo-Nepal Muzpur-Dhalkebad Interconnection.pdf	Map	This is a map of the area between Muzaffarpur (India) and Dhalkebar (Nepal) with some of the most important substations and links.
19	congestion-monitoring.pdf	Web Site	This is a snap-shot of the web-site http:/nldc.in/ . It gives values of the transmission system congestion between different areas of India.
20	ATC_NLDC_Jan'15_Rev20.pdf	Report	This is a report from the Indian national Load Dispatch Centre about transfer capability limit events. The document shows long and short term open access capability.
21	AREng1112.pdf	Report	This is the annual report of the Central electricity Regulatory Commission for the period 2011-2012. It has information about the operation and cost of transmission contracts for that period.
22	3rd_report_Pradeep.pdf	Report	This report is a very detailed study of the Indian interconnections between regions and neighboring countries for the future transmissions plans (2014-2034). The document contents many results which are valuable to test other model of the same

			network, and a lot of information about the possible infrastructure that will come in the following years.
23	PRDC_Harmonization of Grid Codes of South Asia_ 20April.docx	Report	This report explains some of the cross-border transmission link between India and its neighbours. There is information about location, technology and ratings of the future transmission links.
24	India-Nepal future links conceived.docx	Map	This map stresses four different 400kV power links which are expected to be built between India and Nepal.
25	Essar WR-NR perspective.docx	Report	This report shows the interconnection scenario for the border between the North and the Western region of India. There are several tables with the transfer capacity of important transmission lines.
26	Analysis of CEA forecast.docx	Report	This report shows the surplus and deficit energy between different regions of India
27	ADB Vision Paper 9 April 15.docx	Report	This document depicts a desirable cross-border interconnection scenario for the South Asia region.
28	2020_Assessment of TTC to SR.docx	Report	This report explains the congestion problems between western and southern regions of India
29	Note_India-Pakistan_Electricity_Transmission_Link-07May2012.doc	Report	This is a short description of a future interconnection between India and Pakistan.
30	procedures.docx	Report (Internet)	Related to Eastern region

31	OP-ERLDC.pdf	Report (Internet)	Related to Eastern region
32	Power Map of ER June 2014.pdf	Report (Internet)	Related to Eastern region
33	RESTORATION ER -Nov 2013.pdf	Report (Internet)	Related to Eastern region
34	list.xls	Report (Internet)	Related to Eastern region
35	2012 07 24 VISSION 2022.pdf	Report (Internet)	Related to North Eastern region, Arunachal Pradesh
36	2015 01 16 FINAL AOP 2014-15.pdf	Report (Internet)	Related to North Eastern region, Arunachal Pradesh
37	2013 06 19 Technical viability of the Comprehensive Schemes for syrengthening of Transmission & Distbn System.pdf	Report (Internet)	Related to North Eastern region, Arunachal Pradesh
38	Krung.pdf	Report (Internet)	Related to North Eastern region, Arunachal Pradesh
39	Ar Pradesh_PM.pdf	Report (Internet)	Related to North Eastern region, Arunachal Pradesh
40	Ar Pradesh_SLD.pdf	Report (Internet)	Related to North Eastern region, Arunachal Pradesh
41	Chandrapur_Thermal_Power_station.pdf	Report (Internet)	Related to North Eastern region, Assam
42	Final IEE & EMP.pdf	Report (Internet)	Related to North Eastern region, Assam
43	Updated_Draft IEE & EMP Report_Nov 2014.pdf	Report (Internet)	Related to North Eastern region, Assam
44	VISION 2020 DOCUMENT.pdf	Report (Internet)	Related to North Eastern region, Assam
45	Power Map RS1.jpg	Report (Internet)	Related to North Eastern region, Assam
46	20140127_Assam_IEE_Tranche_RSES_INPUT.pdf	Report (Internet)	Related to North Eastern region, Assam
47	Assam_PM.pdf	Report (Internet)	Related to North Eastern region, Assam
48	Assam_SLD.pdf	Report (Internet)	Related to North Eastern region, Assam
49	Updated_ BTPS RP_Nov 18, 2014.pdf	Report (Internet)	Related to North Eastern region, Assam
50	Manipur_PM.pdf	Report (Internet)	Related to North Eastern region, Manipur
51	Manipur_SLD.pdf	Report (Internet)	Related to North Eastern region, Manipur
52	Selim_HEP.pdf	Report (Internet)	Related to North Eastern region,

			Meghalaya
53	Maximum_Minimum_Average Demand.pdf	Report (Internet)	Related to North Eastern region, Meghalaya
54	Detail_Location_of Stations.pdf	Report (Internet)	Related to North Eastern region, Meghalaya
55	Grid_sub-Stations.pdf	Report (Internet)	Related to North Eastern region, Meghalaya
56	AC Transmission lines.pdf	Report (Internet)	Related to North Eastern region, Meghalaya
57	Load Centre Demand_HEP Data.pdf	Report (Internet)	Related to North Eastern region, Meghalaya
58	MeECL POWER FLOW29.03.15.pdf	Report (Internet)	Related to North Eastern region, Meghalaya
59	Meghalaya.pdf	Report (Internet)	Related to North Eastern region, Meghalaya
60	Meghalaya_PM.pdf	Report (Internet)	Related to North Eastern region, Meghalaya
61	Meghalaya_SLD.pdf	Report (Internet)	Related to North Eastern region, Meghalaya
62	annual-report-2011-12.pdf	Report (Internet)	Related to North Eastern region, Mizoram
63	hydro-power-policy-of-mizoram.pdf	Report (Internet)	Related to North Eastern region, Mizoram
64	Mizoram_PM.pdf	Report (Internet)	Related to North Eastern region, Mizoram
65	Mizoram_SLD.pdf	Report (Internet)	Related to North Eastern region, Mizoram
66	NERPowerMap.pdf	Report (Internet)	Related to North Eastern region, Mizoram
67	sld-of-power-network.pdf	Report (Internet)	Related to North Eastern region, Mizoram
68	tariff-for-april-2015-16.pdf	Report (Internet)	Related to North Eastern region, Mizoram
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70	Dikhu.pdf	Report (Internet)	Related to North Eastern region, Nagaland
71	Nagaland_PM.pdf	Report (Internet)	Related to North Eastern region, Nagaland
72	Nagaland_SLD.pdf	Report (Internet)	Related to North Eastern region, Nagaland
73	Dev_Trans_Sys.pdf	Report (Internet)	Related to North Eastern region, Tripura
74	Power_Map.pdf	Report (Internet)	Related to North Eastern region, Tripura
75	powermap.pdf	Report (Internet)	Related to North Eastern region, Tripura
76	Proposed_Transmission_Line.pdf	Report (Internet)	Related to North Eastern region, Tripura
77	service.pdf	Report (Internet)	Related to North Eastern region, Tripura
78	Tripura_PM.pdf	Report (Internet)	Related to North Eastern region, Tripura
79	Tripura_SLD.pdf	Report (Internet)	Related to North Eastern region, Tripura
80	Presentation-Pallatana-DONER Meeting 19-05-2011.ppt	Report (Internet)	Related to North Eastern region, Tripura
81	PRACTICES ADOPTED IN RLDC+NLDC-NERLDC.docx	Report (Internet)	Related to North Eastern region
82	InstalledCapacity.pdf	Report (Internet)	Related to North Eastern region
83	List of Important Grid Elements of NER-2014-15.pdf	Report (Internet)	Related to North Eastern region
84	NER_REACTIVE_POWER_MANAGEMENT_MANUAL_2013.pdf	Report (Internet)	Related to North Eastern region
85	Operating Procedure of NER-July 2014.pdf	Report (Internet)	Related to North Eastern region
86	PoC_RegUsr_NERLDC.pdf	Report (Internet)	Related to North Eastern region
87	Power Map of NER Grid.pdf	Report (Internet)	Related to North Eastern region
88	Restoration Procedure of NER.pdf	Report (Internet)	Related to North Eastern region
89	Restoration Procedure of NER Grid Nov-2013.pdf	Report (Internet)	Related to North Eastern region
90	SLD of NER Grid.pdf	Report (Internet)	Related to North Eastern region
91	Identified Radial Feeders for Emergency LS.xlsx	Report (Internet)	Related to North Eastern region
92	NER Power Map.gif	Report (Internet)	Related to North Eastern region
93	NERPowerMap.pdf	Report	Related to North

		(Internet)	Eastern region
94	Action_Plan_for_Power.ppt	Report (Internet)	Related to North Eastern region
95	ER_100415_R1.xls	Report (Internet)	Related to North Eastern region
96	PRACTICES_nrldc.docx	Report (Internet)	Related to North region
97	Important Grid Element of Northern Region-2014-15.pdf	Report (Internet)	Related to North region
98	Important Grid Element of Northern Region-2014-15.pdf	Report (Internet)	Related to North region
99	NR_Mapbook_2014.pdf	Report (Internet)	Related to North region
100	Operating Procedures of NR_2014-15.pdf	Report (Internet)	Related to North region
101	System Restoration Procedure_NR_2014.pdf	Report (Internet)	Related to North region
102	Andhra-Pradesh(2000).pdf	Report (Internet)	Related to South region
103	BSRP_SR_2014.pdf	Report (Internet)	Related to South region
104	merged (1).pdf	Report (Internet)	Related to South region
105	Operating_Procedure_2014.pdf	Report (Internet)	Related to South region
106	power maps.pdf	Report (Internet)	Related to South region
107	RPM_SR 2013.pdf	Report (Internet)	Related to South region
108	Transmission Grid Elements in SR as on 31.03.2014.pdf	Report (Internet)	Related to South region
109	Neelam_cyclone_SRGrid.ppt	Report (Internet)	Related to South region
110	Message conditions.xls	Report (Internet)	Related to South region
111	PRACTICES.docx	Report (Internet)	Related to Western region
112	LIST OF IMPORTANT GRID ELEMENTS in WR_May_2014.pdf	Report (Internet)	Related to Western region
113	Recovery Procedure 2013_WR_Final.pdf	Report (Internet)	Related to Western region
114	WR Map Book.pdf	Report (Internet)	Related to Western region
115	WR Reactive Power Document 30 Nov 2013.pdf	Report (Internet)	Related to India, CERC
116	WR_OPERATING_PROCEDURE_2014.pdf	Report (Internet)	Related to India, CERC
117	list_USERS_WR.xls	Report (Internet)	Related to India, CERC
118	Development_of_Grid_Code_for_Wind_Power_Generation_in_India_powerpoint-	Report (Internet)	Related to India, CERC

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119	dsm gazzete.pdf	Report (Internet)	Related to India, CERC
120	iegc ammendment.pdf	Report (Internet)	Related to India, CERC
121	iegc gazzete.pdf	Report (Internet)	Related to India, CERC
122	IEGC updated till 2014.pdf	Report (Internet)	Related to India, CERC
123	open access ammendment 2013.pdf	Report (Internet)	Related to India, CERC
124	prcodure for real time congestion.pdf	Report (Internet)	Related to India
125	tr_plg_criteria_manual_jan13.pdf	Report (Internet)	Related to India
126	URS.pdf	Report (Internet)	Related to India
127	TAL STG-II SCH GUIDELINES LTR to SRPC 2.3.12.doc	Report (Internet)	Related to India
128	All India SPS Document.pdf	Report (Internet)	Related to India
129	Compiled power maps of all Regions-2014.pdf	Report (Internet)	Related to India
130	forth.pdf	Report (Internet)	Related to India
131	Maps as on Sept14.pdf	Report (Internet)	Related to India
132	National Grid Compendium.pdf	Report (Internet)	Related to India
133	Operating Procedure of NLDC August2014 Rev 0.pdf	Report (Internet)	Related to India
134	Operators_Handbook.pdf	Report (Internet)	Related to India
135	outage_planning.pdf	Report (Internet)	Related to India
136	SR_NEW_GRID_SPS_MODIFICATIONS.pdf	Report (Internet)	Related to India
137	Tarriff.pdf	Report (Internet)	Related to India
138	Transmission_elements.pdf	Report (Internet)	Related to India
139	CALCULATION.xls	Report (Internet)	Related to India
140	Disaster mangmt list.xls	Report (Internet)	Related to India
141	NLDC_Important_Element_2014.xls	Report (Internet)	Related to India
142	PRACTICES ADOPTED IN NLDC.doc	Report (Internet)	Related to India, National Dispatch Center
143	eommunication from ed nldcpdf.pdf	Report	Related to India,

		(Internet)	National Dispatch Center
144	NLDC_Reactive Power Management_ Dec 2013 .pdf	Report (Internet)	Related to India, National Dispatch Center
145	NLDC_Restoration Procedures_ Dec 2013 Rev 0.pdf	Report (Internet)	Related to India, National Dispatch Center
146	Operating Procedure of NLDC July 2013 Rev 0.pdf	Report (Internet)	Related to India, National Dispatch Center
147	Power maps_All Regions_ 2013.pdf	Report (Internet)	Related to India, National Dispatch Center
148	ElecGenDec14.csv	Report (Internet)	Related to India, National Dispatch Center
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22 Appendix M - Terms of Reference

22.1 TA-8619 REG: South Asia Sub-regional Economic Cooperation Cross-Border Power Trade Development - Power System Economist and Team Leader (47107-001)

Objective and Purpose of the Assignment

Asian Development Bank recently approved a regional capacity development technical assistance (R-CDTA) on South Asia Sub-regional Economic Cooperation (SASEC) Cross-border Power Trade Development. Under this R-CDTA the consultants will provide a comprehensive study of generation and transmission development opportunities in the region, focusing on increasing opportunities for cross-border electricity trade among member states of the South Asia Sub-regional Economic Cooperation (SASEC) and Afghanistan and Pakistan. The technical assistance (TA) will be executed and implemented by the Asian Development Bank (ADB) with the assistance and guidance of the South Asia countries. The consultants will be recruited in accordance with ADB Guidelines on the Use of Consultants (2013, as amended from time to time). Disbursements under the TA will be made in accordance with ADB's Technical Assistance Disbursement Handbook (2010, as amended from time to time).

Scope of Work

The consultant will perform, but not limited to, the tasks below:

i. act as the team leader responsible for consolidating and compiling the inception report, interim report, draft final report, and final report and presentations at all the meetings and dissemination activities;
ii. supervise the data collection efforts and closely interact with the power system planning specialist to ensure consistency of assumptions that form inputs to the planning optimization studies;
iii. undertake a literature review of international best practice in interconnection planning including regulatory processes, planning methods, modeling techniques, and implementation of generation and transmission planning models for real-life power systems;
iv. develop a set of scenarios for a regional transmission planning exercise combining an internally consistent set of key parameters around demand growth, fuel price, renewable and non-renewable resource availability, and carbon reduction targets;
v. undertake a composite generation and transmission planning optimization model in 2014–2030 for South Asia to identify economic cross-border opportunities covering a base case and at minimum three major scenarios;
vi. based on the findings of the modeling exercise, develop a detailed cost–benefit analysis of alternative transmission expansion options for interregional power trading, including benefits disaggregated by country for each of the transmission links;
vii. develop an analysis of renewable power development in the region, including a comparative analysis of national renewable energy targets vis-à-vis regional renewable energy targets, taking into consideration the stochastic nature of renewable energy resources;

viii. develop a clear set of recommendations on long-term cross-border transmission capacity to promote renewable energy development in the region, along with justifications based on benefits to individual countries; and

ix. assist ADB in arranging capacity development programs, including meetings, related to SETUF activities.

Detailed Tasks and/or Expected Output

The consultant will perform, but not limited to, the tasks below:

i. act as the team leader responsible for consolidating and compiling the inception report, interim report, draft final report, and final report and presentations at all the meetings and dissemination activities;

ii. supervise the data collection efforts and closely interact with the power system planning specialist to ensure consistency of assumptions that form inputs to the planning optimization studies;

iii. undertake a literature review of international best practice in interconnection planning including regulatory processes, planning methods, modeling techniques, and implementation of generation and transmission planning models for real-life power systems;

iv. develop a set of scenarios for a regional transmission planning exercise combining an internally consistent set of key parameters around demand growth, fuel price, renewable and non-renewable resource availability, and carbon reduction targets;

v. undertake a composite generation and transmission planning optimization model in 2014–2030 for South Asia to identify economic cross-border opportunities covering a base case and at minimum three major scenarios;

vi. based on the findings of the modeling exercise, develop a detailed cost–benefit analysis of alternative transmission expansion options for interregional power trading, including benefits disaggregated by country for each of the transmission links;

vii. develop an analysis of renewable power development in the region, including a comparative analysis of national renewable energy targets vis-à-vis regional renewable energy targets, taking into consideration the stochastic nature of renewable energy resources;

viii. develop a clear set of recommendations on long-term cross-border transmission capacity to promote renewable energy development in the region, along with justifications based on benefits to individual countries; and

ix. assist ADB in arranging capacity development programs, including meetings, related to SETUF activities.

22.2 TA-8619 REG: South Asia Sub-regional Economic Cooperation Cross-Border Power Trade Development - Power System Planning Specialist (47107-001)

Objective and Purpose of the Assignment

Asian Development Bank recently approved a regional capacity development technical assistance (R-CDTA) on South Asia Sub-regional Economic Cooperation (SASEC) Cross-border Power Trade Development. Under this R-CDTA the consultants will provide a comprehensive study of generation and transmission development opportunities in the region, focusing on increasing opportunities for cross-border electricity trade among member states of the South Asia Sub regional Economic Cooperation (SASEC). The technical assistance (TA) will be executed and implemented by the Asian Development Bank (ADB) with the assistance and guidance of the South Asian countries. The consultants will be recruited in accordance with ADB Guidelines on the Use of Consultants (2013, as amended from time to time). Disbursements under the T A will be made in accordance with ADB's Technical Assistance Disbursement Handbook (2010, as amended from time to time).

Scope of Work

The consultant will perform, but not limited to, the tasks below:

i. develop the necessary regional load flow database, compiling the available PSS/E™ database available for South Asian power systems;
ii. develop a zonal approximation of the integrated South Asian power system suitable for long-term planning optimization;
iii. develop alternative cross-border transmission capacity expansion scenarios;
iv. collect detailed generation expansion planning data for all South Asian countries (e.g., background data to the National Electricity Plan, 2012 in the case of India) including (a) generation plans with power station names, capacity, cost, etc.; (b) demand projections; (c) reliability criteria; and (d) generation development scenarios;
v. develop a common set of power system planning assumptions for the region up to 2030, collating existing plans and any generic assumptions needed; and
vi. prepare a model database for generation-transmission planning software used by the power system economist and team leader (cleaning, inputting, and checking all country data).

Detailed Tasks and/or Expected Output

The consultant will perform, but not limited to, the tasks below:

i. develop the necessary regional load flow database, compiling the available PSS/E™ database available for South Asian power systems;
ii. develop a zonal approximation of the integrated South Asian power system suitable for long-term planning optimization;
iii. develop alternative cross-border transmission capacity expansion scenarios;
iv. collect detailed generation expansion planning data for all South Asian countries (e.g., background data to the National Electricity Plan, 2012 in the case of India) including (a) generation plans with power station names, capacity, cost, etc.; (b)

demand projections; (c) reliability criteria; and (d) generation development scenarios;

v. develop a common set of power system planning assumptions for the region up to 2030, collating existing plans and any generic assumptions needed; and

vi. Prepare a model database for generation-transmission planning software used by the power system economist and team leader (cleaning, inputting, and checking all country data).