Indo-Lanka Power Grid Linkages:
Evaluating Technical and Economical Impact

Project Report – Group 11

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ABSTRACT

This report evaluates the Sri Lanka-India power interconnection's feasibility using economic dispatch modelling. The link enables cheaper electricity imports, reducing local generation costs and optimizing energy use. Analysis of dynamic pricing and unavailability impacts confirms significant savings and grid efficiency gains. Findings support the project as a strategic solution for affordable, sustainable cross-border energy trade.

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ANN	Artificial Neural Network
ASEAN	Association of Southeast Asian Nations
CBET	Cross-Border Electricity Trade
CEB	Ceylon Electricity Board
DSM	Demand Side Management
GDP	Gross Domestic Product
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current
IEX	Indian Energy Exchange
IPP	Independent Power Producer
LKR	Sri Lankan Rupee
LTL	Lanka Transformers Limited
MCP	Market Clearing Price
MCV	Market Clearing Volume
MW	Megawatt
NCRE	Non-Conventional Renewable Energy
NPV	Net Present Value
PPA	Power Purchase Agreement
PUSCL	Public Utilities Commission of Sri Lanka
SL	Sri Lanka
USD	United States Dollar
VSC	Voltage Source Converter

Chapter 1

Introduction

The Indo-Lanka power grid interconnection is a proposed cross-border electricity transmission project designed to link the national power grids of India and Sri Lanka. As part of a broader regional energy cooperation initiative, the project aims to enhance energy security, promote electricity accessibility, and facilitate cross-border electricity trade between the two countries. By integrating Sri Lanka into the South Asian power grid, the interconnection is expected to contribute to a more stable, cost-effective, and sustainable energy supply network.

Sri Lanka faces increasing electricity demand and a heavy reliance on imported fossil fuels for power generation. This interconnection presents a strategic opportunity to access India’s surplus power drawn from a diverse and robust energy mix thereby reducing energy costs and easing dependence on high-cost thermal power plants. In line with global efforts toward regional power market integration, the Indo-Lanka interconnection supports greater energy cooperation and advances the shared goals of economic and environmental sustainability.

Chapter 2

Literature Review

2.1 Cross Border Electricity Trade

This refers to the exchange of electrical power between neighboring countries through interconnected transmission networks. It allows nations to optimize their energy resources, enhance grid stability, and reduce electricity costs while fostering regional cooperation. With increasing energy demand and the global push for sustainable development, CBET plays a crucial role in ensuring efficient energy utilization and economic growth.

One of the primary advantages of CBET is the efficient allocation of energy resources. Some countries have an abundance of renewable energy sources, such as hydropower, solar, or wind, while others experience deficits due to limited resources or high consumption levels. By engaging in electricity trade, surplus power from one country can be used to meet shortages in another, leading to a balanced and cost-effective power supply. This approach also enables nations to reduce dependency on fossil fuels, thereby cutting down greenhouse gas emissions and promoting cleaner energy solutions.

Another key benefit of CBET is the enhancement of energy security and grid stability. Power systems are often vulnerable to disruptions caused by technical failures, natural disasters, or sudden spikes in demand. By interconnecting national grids, countries can access alternative power sources in times of crisis, preventing blackouts and ensuring a steady electricity supply. Moreover, interconnected grids allow better management of peak load periods, where electricity demand is high in one region but lower in another, enabling efficient distribution of available power.

From an economic perspective, CBET encourages investment in power infrastructure and strengthens regional energy markets. When countries engage in electricity trade, they are incentivized to develop robust transmission networks, modernize power plants, and implement smart grid technologies. This investment not only improves domestic power systems but also creates opportunities for job growth, technological innovation, and industrial development. Additionally, by fostering competition in energy markets, CBET helps in achieving competitive electricity pricing, which benefits consumers and industries alike.

2.2 Earlier Proposals of Indo–Lanka Power Grid Linkage

Original Proposed Configuration

The initial feasibility study for the Indo-Lanka power grid interconnection considered a 360 km High Voltage Direct Current (HVDC) bipolar link with two 500 MW terminal stations. The major components of this configuration included:

1.Overhead Transmission Line in India

- A 130 km transmission line from Madurai to Panaikulam, carrying power from the Indian grid towards the interconnection point.

2.Submarine Cable Segment

- A 120 km undersea cable from Panaikulam (India) to Thirukketiswaram (Sri Lanka), transmitting power across the Palk Strait.

3.Overhead Transmission Line in Sri Lanka

- A 110 km transmission line from Thirukketiswaram to Anuradhapura, integrating the imported electricity into Sri Lanka's national grid.

The estimated cost of this configuration in 2012 was approximately USD 1.03 billion for conventional HVDC technology and USD 1.11 billion for Voltage Source Converter (VSC)-based HVDC.

Revised Configuration for Cost Reduction

To optimize costs and improve feasibility, a revised shorter route was proposed, significantly reducing the submarine cable length to 40 km. The new configuration consists of:

1. Overhead Transmission Line in India
   - 180 km transmission line from Madurai to near Dhanushkodi.
2. Submarine Cable Segment
   - A 40 km undersea cable from Dhanushkodi (India) to Talaimannar (Sri Lanka), significantly reducing underwater infrastructure costs.
3. Overhead Transmission Line in Sri Lanka
   - A 150 km transmission line from Talaimannar to Anuradhapura.

With this revised configuration, the estimated project costs dropped to USD 515 million for conventional HVDC technology and USD 564 million for VSC-based HVDC as of 2016.

Figure 2.1 HVDC link between India and Sri Lanka

Alternative Route Options and Considerations

Several alternative routing options have also been explored, considering technical feasibility, environmental impact, and cost-effectiveness. The key options include:

Option 1

1. Overhead Line (India): Madurai(New) to Panaikulam: 130km
2. Submarine Cable: Panaikulam (India) to Thirukketiswaram (SL): 120km
3. Overhead Line (SL): Thirukketiswaram to New Habarana: 160km

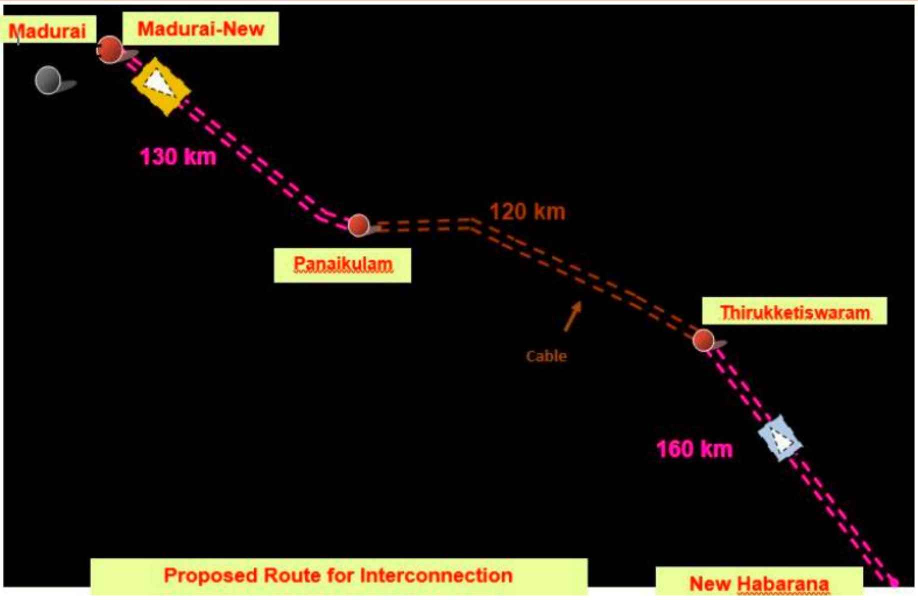

Figure 2.2 Alternative route option 1 of Indo – Lanka Grid Linkage

Option 2

1. Overhead Line (India): Madurai (New) to near Dhanushkodi: 180km
2. Submarine Cable: Dhanushkodi (India) to Talaimannar (SL): 40km
3. Overhead Line (SL): Talaimannar to New Habarana: 200km

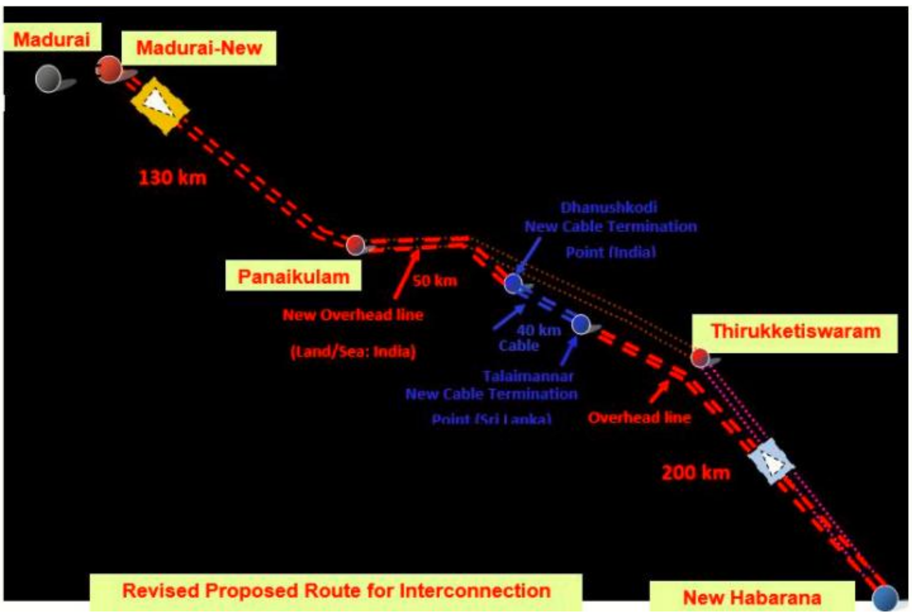

Figure 2.3 Alternative route option 2 of Indo – Lanka Grid Linkage

Option 3

1. Overhead Line (India): Madurai(New) to near Dhanushkodi: 180km
2. Submarine Cable: Dhanushkodi (India) to Thirukketiswaram (SL): 70km
3. Overhead Line (SL): Thirukketiswaram to New Habarana: 160km

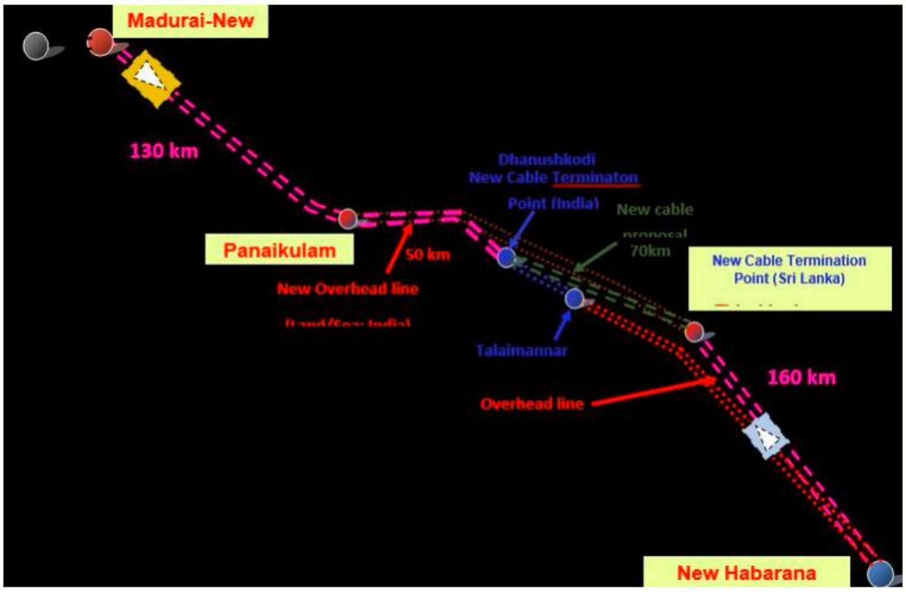

Figure 2.4 Alternative route option 3 of Indo – Lanka Grid Linkage

2.3 India’s Grid Linkages with other countries

India’s Grid Connection with South Asian Countries: Infrastructure and Impacts
India has emerged as the central pillar in South Asia’s efforts to integrate regional electricity networks, leveraging its extensive power generation base, advanced grid infrastructure, and mature electricity market. It shares physical electricity interconnections with Bhutan, Nepal, Bangladesh, and Myanmar, with plans underway to connect Sri Lanka via an undersea high-voltage link. These cross-border electricity links are not only technical feats but also instruments of economic development, social progress, and regional diplomacy.

India’s energy partnership with Bhutan is the most mature in the region. Bhutan exports over 2,100 MW of hydroelectric power to India, constituting a critical component of its national revenue estimated at more than 40% of its GDP. India has financed and constructed many of Bhutan’s key hydropower plants, such as Tala, Chhukha, and Dagachhu, under bilateral agreements. Electricity is transmitted through 400 kV lines like the Tala–Siliguri link, jointly owned and maintained. This partnership has made Bhutan a model of green energy export in the region and exemplifies mutually beneficial energy diplomacy.

Nepal’s electricity exchange with India has undergone a transformation in recent years. The 400 kV Dhalkebar–Muzaffarpur line has enabled large-scale transfers, complemented by multiple lower voltage lines that support regional flows. Historically dependent on imports from India during dry seasons, Nepal has now begun exporting surplus electricity, especially during the monsoon, thanks to its expanding hydropower base. Significantly, Nepal has gained access to India’s Day-Ahead Market through the IEX, signaling a shift toward market-based regional trade and integration.

India and Bangladesh maintain a robust and growing power trading relationship. Bangladesh currently imports over 1,160 MW of power through two main interconnections: the 400 kV HVDC link between Baharampur (India) and Bheramara (Bangladesh), and a 132 kV line between Tripura and Comilla. These imports are critical to Bangladesh’s industrial growth and urban electricity needs. The bilateral cooperation has also expanded into joint infrastructure projects, including generation plants like the Rampal coal plant. Additional interconnections and increased capacity are being planned to meet Bangladesh’s rising demand.

Though smaller in scale, India’s connection with Myanmar holds strategic importance. Electricity is supplied through a 33 kV line from Manipur to Tamu in Myanmar, aimed primarily at electrifying border regions. While current volumes are modest, the interconnection lays the groundwork for future expansion in line with India’s “Act East Policy” and broader ASEAN-South Asia power integration plans.

2.4 Electricity Market Economics

Electricity is a unique and essential commodity that differs significantly from traditional goods. It must be produced and consumed simultaneously, as large-scale storage is still limited and expensive. This instantaneous balancing requirement makes the dynamics of supply and demand in electricity markets particularly critical. Understanding these interactions is essential for maintaining reliable service, ensuring efficient market operations, and guiding long-term investment in generation and infrastructure.

Electricity demand refers to the total amount of electrical energy required by consumers at any given time. This demand is influenced by several factors including the time of day, weather conditions, economic activity, and the nature of consumption whether residential, commercial, or industrial. Typically, electricity demand is relatively inelastic in the short term, meaning that consumers do not significantly change their usage in response to price fluctuations. This inelasticity can lead to sharp price spikes during periods of high demand or constrained supply.

On the other hand, electricity supply is determined by the available generation capacity, which includes thermal, hydroelectric, nuclear, and increasingly, renewable sources such as wind and solar. The ability of generators to produce electricity depends on factors such as fuel availability, maintenance schedules, and weather patterns particularly for renewables. Unlike demand, supply is often more price-sensitive, especially in deregulated markets where generators respond to price signals to maximize profit. However, the supply side also faces physical and operational constraints, such as ramp-up times and transmission limits.

Electricity markets are structured to balance supply and demand through various mechanisms. These markets can be either regulated, where government agencies set prices and manage dispatch, or deregulated, where competitive forces determine prices and operations. Key components include the wholesale market, where electricity is bought and sold in bulk, and the retail market, which delivers electricity to end-users. Additionally, electricity trading occurs in both day-ahead markets, where supply and demand are forecasted, and real-time markets, which adjust for actual conditions.

The intersection of supply and demand in these markets determines the market-clearing price. However, due to the inelastic nature of demand and the variability of supply particularly with renewables electricity prices can be highly volatile. Price spikes often occur during peak demand periods or when supply is disrupted due to outages or fuel shortages. To manage this, some markets implement price caps and floors to protect consumers and ensure system reliability.

To further address demand-side challenges, many utilities and grid operators implement Demand Side DSM programs. These include time-of-use pricing, demand response initiatives, and smart metering technologies that encourage consumers to shift usage away from peak periods. Such measures help reduce the strain on the grid, lower operational costs, and defer the need for costly infrastructure investments.

Supply-side challenges are equally significant. The intermittent nature of renewable energy sources like solar and wind introduces variability that must be balanced with more controllable sources or energy storage. Additionally, many power systems are constrained by aging infrastructure, fuel import dependencies, and increasingly stringent environmental regulations. All these factors affect the reliability, sustainability, and economics of electricity supply. Several real-world cases illustrate the complex interplay of supply and demand in electricity markets

2.5 Competitive Electricity Bidding

Competitive electricity bidding is a fundamental mechanism in deregulated electricity markets, designed to promote efficiency, transparency, and fair pricing through market-based competition. In this system, electricity generators submit price and quantity bids for supplying power to the grid, and the system operator selects the most economical combination of bids to meet the projected demand. The main objective of this competitive bidding process is to minimize the total cost of generation while ensuring reliability and grid stability. This approach contrasts with vertically integrated utilities in regulated markets, where prices and generation are centrally controlled.

In a typical competitive market, generators submit bids specifying how much electricity they are willing to supply and at what price for each trading period, usually in a day-ahead or real-time market. These bids are arranged in ascending order of price to form the supply stack or merit order. MCP is set by the highest accepted bid required to meet the forecasted demand. All dispatched generators are then paid this uniform clearing price, encouraging them to offer competitive rates to ensure selection.

This system incentivizes generators to operate efficiently and invest in cost-effective technologies. It also enables the integration of diverse generation sources, including renewables and IPPs. However, competitive bidding also brings challenges such as market power manipulation, volatility in prices, and underinvestment in reserve capacity if not properly regulated. Therefore, appropriate market design, oversight, and ancillary service mechanisms are essential to maintain balance and prevent failures.

An important concept closely tied to competitive bidding is the reserve margin, which refers to the extra generation capacity available over the expected peak demand. It acts as a buffer to accommodate unexpected increases in demand, generator outages, or transmission failures. In market bidding contexts, maintaining an adequate reserve margin is crucial for ensuring system reliability and avoiding blackouts. Typically, a reserve margin of 10–20% is considered sufficient, though it varies depending on the market structure and regional reliability standards.

In electricity markets, reserve requirements are managed through various mechanisms. System operators may procure operating reserves such as spinning, non-spinning, and supplemental reserves through separate ancillary service markets or include them as part of the bidding process. Generators are often incentivized or obligated to hold some of their capacity in reserve to respond quickly in case of supply shortfalls. In some cases, capacity markets are established in parallel with energy markets to compensate generators simply for being available, thus ensuring that adequate reserve margins are maintained even if actual energy dispatch is low.

When bidding in a competitive market, generators must consider reserve margin policies while formulating their strategies. If reserve margins are tight, market prices tend to rise, increasing the profit opportunity for flexible and fast-ramping generators. Conversely, when reserve margins are high, prices can fall due to oversupply, pressuring less efficient generators. These dynamics make reserve margin forecasts a critical factor in market planning and bidding behavior.

2.6 CEB Long term generation plan

According to the CEB Long-Term Generation Expansion Plan (2025), a unit cost table for the proposed interconnection has been presented. In India, economic dispatch is carried out in 15-minute intervals, whereas in Sri Lanka, it is conducted on an hourly basis for each day. In the CEB plan, hourly dispatch has been considered, and the interconnection price has been averaged to a constant value for an entire month. However, the methodology adopted to derive these values has not been clearly explained, nor has it been specified whether unavailability scenarios were taken into account. Table 1, extracted from the CEB Long-Term Generation Plan, presents the average unit cost in Rs/kWh. The original values were expressed in USD cents, but for the purpose of this study, they were converted into Sri Lankan Rupees (LKR) using an exchange rate of 1 USD = 300 LKR.

Table 2.1: Average Unit Cost of Indian Interconnection

Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
1	9.51	11.73	34.62	47.94	37.5	42.84	29.31	22.38	25.38	15.24	15.78	13.05
2	9.18	11.31	31.74	46.77	33.27	36.54	23.55	19.14	21.81	14.43	14.97	12.33
3	8.88	10.89	27.84	45.6	30.3	31.56	19.71	17.1	19.71	13.65	14.46	11.82
4	8.82	10.68	24.81	44.46	28.29	27.93	17.91	16.29	18.18	13.05	14.13	11.76
5	9.12	11.16	25.14	43.74	27.84	29.85	17.43	16.98	18.72	13.65	14.82	12.69
6	11.16	13.98	33.57	45.15	28.05	28.29	20.43	22.92	23.01	15.57	17.58	15.84
7	15.39	25.86	49.86	45.75	26.79	25.35	23.19	25.83	29.37	17.91	20.55	23.4
8	18.81	39.75	53.88	41.07	21.96	18.39	21.93	22.47	23.4	17.4	23.73	35.22
9	21.42	32.19	32.16	35.37	18.12	14.31	16.65	17.46	17.43	14.94	22.2	33.39
10	21.84	25.05	28.53	34.44	18	13.29	14.88	16.02	15.57	13.86	21.39	31.92
11	20.34	23.97	29.94	34.8	19.2	14.61	14.1	14.88	14.91	13.35	20.07	29.04
12	17.91	21.87	28.26	33.84	20.82	15.87	13.62	14.7	14.97	12.72	19.14	24.51
13	15.42	18.36	26.7	30.93	20.76	16.86	13.32	13.77	15	12.15	17.58	20.64
14	12.87	14.31	22.38	28.5	21.6	17.55	12.78	12.9	14.07	11.67	16.74	17.55
15	12.09	13.23	25.83	33.6	25.92	21.72	13.8	14.43	16.32	12.51	17.61	18.66
16	13.08	14.16	30.06	38.16	29.7	25.95	16.29	16.77	19.56	13.71	18.9	21.24
17	14.55	17.34	36.48	40.83	28.95	23.19	17.07	18.81	21.42	15.27	20.52	28.29
18	18.72	23.46	35.82	42	27.93	20.46	17.79	18.93	24.42	19.62	27.54	33.09
19	26.46	30.3	44.79	44.22	28.71	22.56	27.3	27.69	36.96	35.82	35.79	38.04
20	22.32	28.05	49.71	45.81	34.08	38.07	40.38	39.39	45.63	34.8	25.41	32.37
21	16.74	19.89	38.49	44.37	33.96	38.31	41.58	38.46	38.28	21.36	20.79	21.75
22	14.58	16.74	35.64	45.63	37.56	42.48	41.31	37.41	34.95	18.18	19.41	18.63
23	12.3	14.19	34.14	45.75	39.12	43.65	40.26	34.71	32.73	16.83	19.44	15.78
24	10.44	12.42	34.95	47.76	38.85	42.84	36.6	29.01	30.03	15.51	16.77	14.04

Chapter 3

Methodology

The proposed methodology is based on the analysis of the unavailability of the Indian interconnection u sing historical IEX data. Two scenarios, with and without the Indian link, are considered for future economic dispatch simulations. Through this analysis, the power plants that are directly affected by the interconnection are identified. In cases where the Indian link becomes unavailable, the required demand is expected to be met by generation from these identified plants.

In the 2025 CEB Long-Term Generation Expansion Plan, the cost of the Indian interconnection has been explicitly considered. Based on the cost data provided in the plan and the unavailability of the link, the cost variations are analyzed under different scenarios as follows:

1. Scenario 1: Cost with 350 MW of renewable energy (300 MW solar, 50 MW wind), with and without a 500 MW interconnection.
2. Scenario 2: Cost with 45% renewable energy from 2030 onwards, with and without a 500 MW HVDC interconnection.
3. Scenario 3: Cost with 60% renewable energy from 2027 onwards, with and without a 500 MW HVDC interconnection.
4. Scenario 4: Cost with 70% renewable energy from 2030 onwards, with and without a 500 MW HVDC interconnection.
5. Scenario 5: Achieving 70% renewable energy by 2030 and increasing to 80% by 2044, with a 1000 MW HVDC interconnection.

The power plants affected by the interconnection have already been identified, and the potential losses of each plant are estimated accordingly. Furthermore, for each scenario, the profitability of establishing the interconnection is evaluated. The recovery period of the investment is calculated along with the Net Present Value (NPV) to assess the overall economic feasibility.

3.1 Interconnection Availability

3.1.1 Introduction

Cross-border electricity trading plays a crucial role in ensuring energy security, balancing supply and demand, and optimizing the use of diverse power generation resources. However, interconnection power importing can become unavailable during certain periods of the day due to a combination of technical, operational, and market-driven factors. A key determinant is power plant availability in the exporting country, which fluctuates with scheduled maintenance, unexpected outages, or reduced generation from variable renewable sources such as solar and wind. In addition, the domestic demand on the exporting side often rises during peak load hours, limiting the surplus power available for export since meeting local consumption takes priority.

Furthermore, the capacity and reliability of the transmission system play a vital role; congestion, line maintenance, or unexpected faults in the interconnection network can restrict cross-border flows even when generation capacity exists. These interrelated factors highlight that electricity trading is not solely dependent on bilateral agreements but also on the dynamic operational conditions of both power systems, making interconnection imports sometimes unavailable during critical hours of the day.

3.1.2 Market Cost Assessment for Power Imports Using Supply–Demand Curves

In electricity markets, supply and demand curves are powerful tools for assessing whether power is available for purchase at a given time. The supply curve represents the amount of electricity generators are willing to produce at different price levels, starting with the lowest-cost sources such as hydro or renewables and moving up to more expensive plants such as gas or oil. Conversely, the demand curve reflects the quantity of electricity consumers require at varying prices, typically higher during peak hours when households, industries, and commercial facilities operate simultaneously. The point where these two curves intersect indicates the market-clearing price and the volume of electricity that can be transacted. When assessing availability for cross-border purchase, one must examine whether the exporting country's supply curve, after meeting its own domestic demand, still has surplus generation capacity left. If the domestic demand curve already consumes the majority of supply at or below the market-clearing price, little to no electricity remains available for export.

Figure 3.1.1 Supply-Demand Curve of IEX on 17th July 2025 from 00.00 a.m.-00.15a.m.

To assess the value of power purchasing, data from the Indian Energy Exchange (IEX) platform was used, as it accounts for nearly 98% of India's cross-border electricity trading activities. The IEX operates through two major market segments:

1. Day Ahead Market (DAM)
2. Real Time Market (RTM)

The Day Ahead Market, which forms part of the Integrated Day Ahead Market (DAM), is a physical electricity trading platform where participants buy and sell electricity for delivery on the following day. Prices and traded quantities are determined through a double-sided closed auction bidding process, ensuring transparency and competitiveness.

The Real Time Market is designed for near-instantaneous electricity trading, with physical delivery of power occurring just one hour after market closure. The RTM operates with 48 auction sessions per day, each held every half an hour, and power is delivered four-time blocks (one hour) after the gate closure of the respective session. Similar to DAM, prices and volumes in RTM are also determined through a double-sided closed auction.

For our analysis, we relied on Real Time Market (RTM) values rather than Day Ahead Market (DAM) values. The RTM is more suitable for assessing cross-border electricity trading costs because it reflects the actual, real-time balance of supply and demand closer to the moment of delivery. Unlike DAM, which is based on forecasts and next-day scheduling, RTM prices capture the true volatility of power availability, including sudden fluctuations in demand, renewable energy output, or unforeseen generator outages. This makes RTM data a more accurate representation of market dynamics, especially when evaluating the feasibility and cost of power imports across borders, where availability is often constrained by short-term generation surpluses and transmission capacity. Hence, RTM provides a more realistic foundation for assessing the cost and availability of electricity in cross-border trading scenarios.

Figure 3.1.2 Indian Energy Exchange Logo

3.1.3 Determining Cross-Border Power Availability Using Supply–Demand Dynamics

As discussed in Section 3.1, there are periods when cross-border electricity trading becomes unavailable due to operational and market constraints. One effective method to identify such scenarios is through the assessment of supply and demand curves, which provide insights into generation availability, domestic consumption patterns, and the surplus capacity that can be allocated for export.

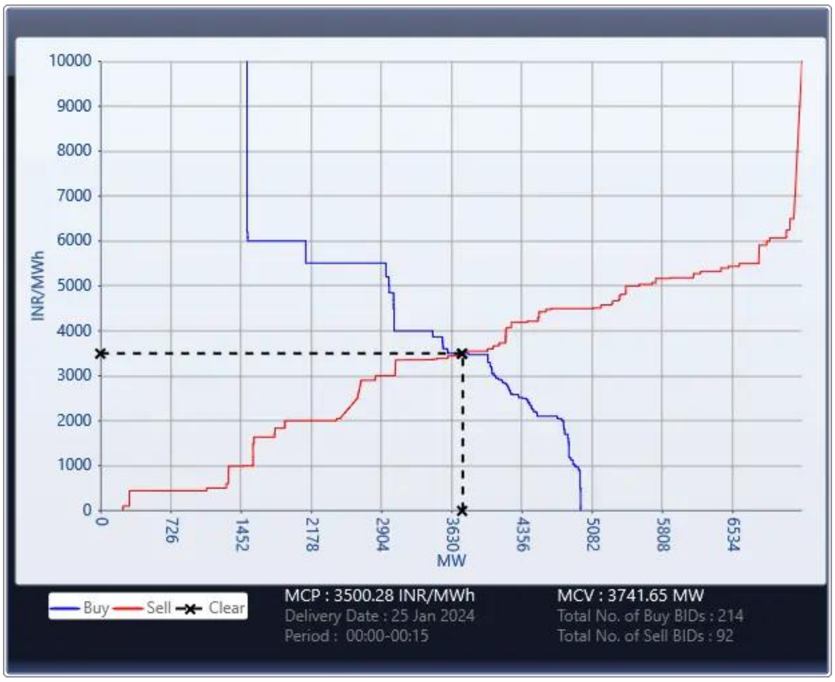

Figure 3.1.3 Cross Boarder Power Trading Available Instance

In figure 3.1.3, the supply and demand curves intersect at a clear and visible point, which represents the Market Clearing Price (MCP) and the Market Clearing Volume (MCV). At this point, the electricity market balances, ensuring that the amount of power supplied matches the amount demanded. Buyers who place bids at or above the MCP are able to purchase electricity up to the MCV, while bids below the MCP are not cleared.

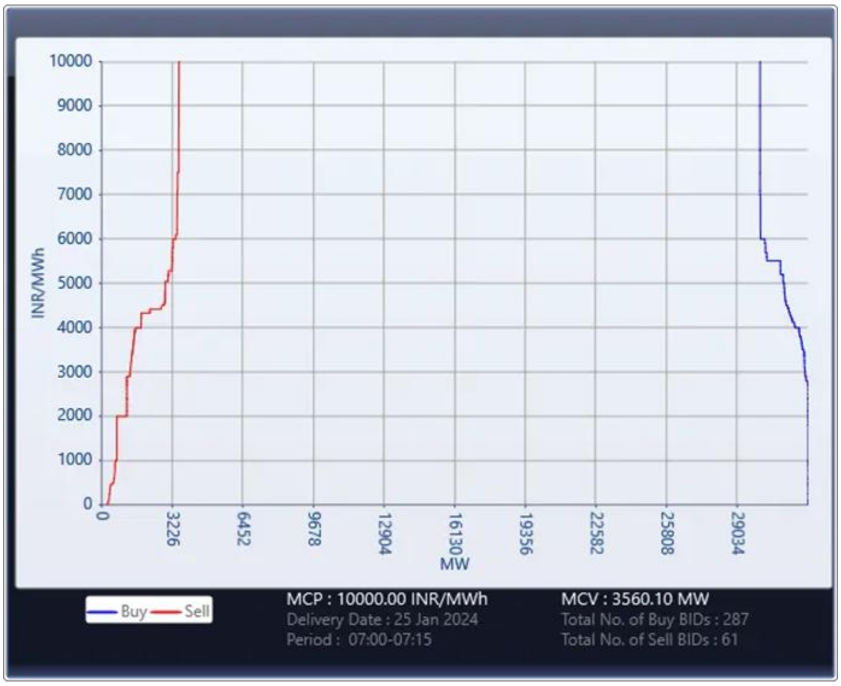

Figure 3.1.4 Cross Boarder Power Trading Unavailable Instance

In Figure 3.1.4, there is no visible intersection point between the supply and demand curves, indicating that the market has not reached a natural equilibrium. In the Indian Energy Exchange (IEX), a maximum Market Clearing Price (MCP) of 10,000 INR/MWh is defined as the bidding cap. However, even if India is exporting some power at that time, it does not guarantee availability for meeting Sri Lanka's local demand, as domestic consumption and bidding priorities within India take precedence. Consequently, this situation is considered an unavailable period for cross-border electricity imports, since Sri Lanka cannot reliably secure the required volume of power despite the presence of exports.

The Indian Energy Exchange (IEX) operates on a 15-minute trading interval, meaning that within a year, a total of 35,040 supply–demand curves would need to be analyzed to capture every trading period. Conducting such a large-scale assessment is highly impractical and resource-intensive. Therefore, alternative method is used to evaluate the availability and unavailability of cross-border electricity trading, focusing on statistical sampling approaches rather than analyzing every single interval.

Date	Hour	Session ID	Time Block	Purchase Bid (MW)	Sell Bid (MW)	MCV (MW)	Final Scheduled Volume (MW)	MCP (Rs/MWh) *
	21	42	20:30-20:45	10202.10	4769.10	4769.10	4769.10	10000.00
			20:45-21:00	10105.90	4804.50	4804.50	4804.50	10000.00
	22	43	21:00-21:15	8490.20	5155.20	5155.20	5155.20	10000.00
			21:15-21:30	8395.00	5264.60	5264.58	5264.58	10000.00
		44	21:30-21:45	5543.40	5860.90	4216.01	4216.01	4600.66
			21:45-22:00	5559.20	6050.30	4308.95	4308.95	4500.27
		45	22:00-22:15	5625.50	6573.80	4821.69	4821.69	3536.08
			22:15-22:30	5612.40	6739.10	4809.70	4809.70	3521.96

Figure 3.1.5 Market Snapshot Table of IEX

As previously mentioned, the Indian Energy Exchange (IEX) sets a maximum Market Clearing Price (MCP) of 10,000 INR/MWh. When this maximum price is reached, it indicates a condition of unavailability, as demand exceeds the available supply at all lower price levels. In such cases, even though trading occurs, the power is not guaranteed for export since domestic demand has already absorbed the supply. Therefore, simply monitoring the MCP value is often sufficient to assess whether power is available for purchase in cross-border trading.

3.1.4 Estimating the Probability of Trading Unavailability

To analyze unavailability in a meaningful way, it must be assessed using different methods, as relying on a single approach may not provide consistent results. Instead of considering unavailability as a fixed outcome, it is more practical to calculate the probability of unavailability, since this measure accounts for variations across different methods and time intervals. By expressing unavailability in terms of probability, the analysis becomes more robust and provides a clearer indication of the likelihood of power not being available, rather than treating it as an absolute condition.

The probability of unavailability is calculated as:

$$\mathrm{P(U)} = \frac{\mathrm{Nu}}{\mathrm{N}t}$$

P(U) = Probability of unavailability

Nu = Number of time intervals in which power is unavailable

Nt = Total number of time intervals considered

This formulation provides a clear quantitative measure of how frequently unavailability occurs within the assessed period.

When counting the number of time intervals in which power is unavailable, it is important to consider the difference between the Indian and Sri Lankan Economic Dispatch time intervals. In the Indian Energy Exchange (IEX), trading is carried out every 15 minutes, whereas Sri Lanka operates on an hourly dispatch interval. Therefore, for Sri Lanka, power can only be considered available if it is continuously available across all four of the corresponding 15-minute intervals within that hour in India. If availability is missing in any of those intervals, the entire hour is treated as unavailable for Sri Lanka. This alignment ensures that the assessment accurately reflects the operational requirements of the Sri Lankan power system.

After calculating the unavailability probabilities, the results are evaluated using different assessment methods. The first method involves analyzing and comparing the probabilities between weekdays and weekends over the course of the year.

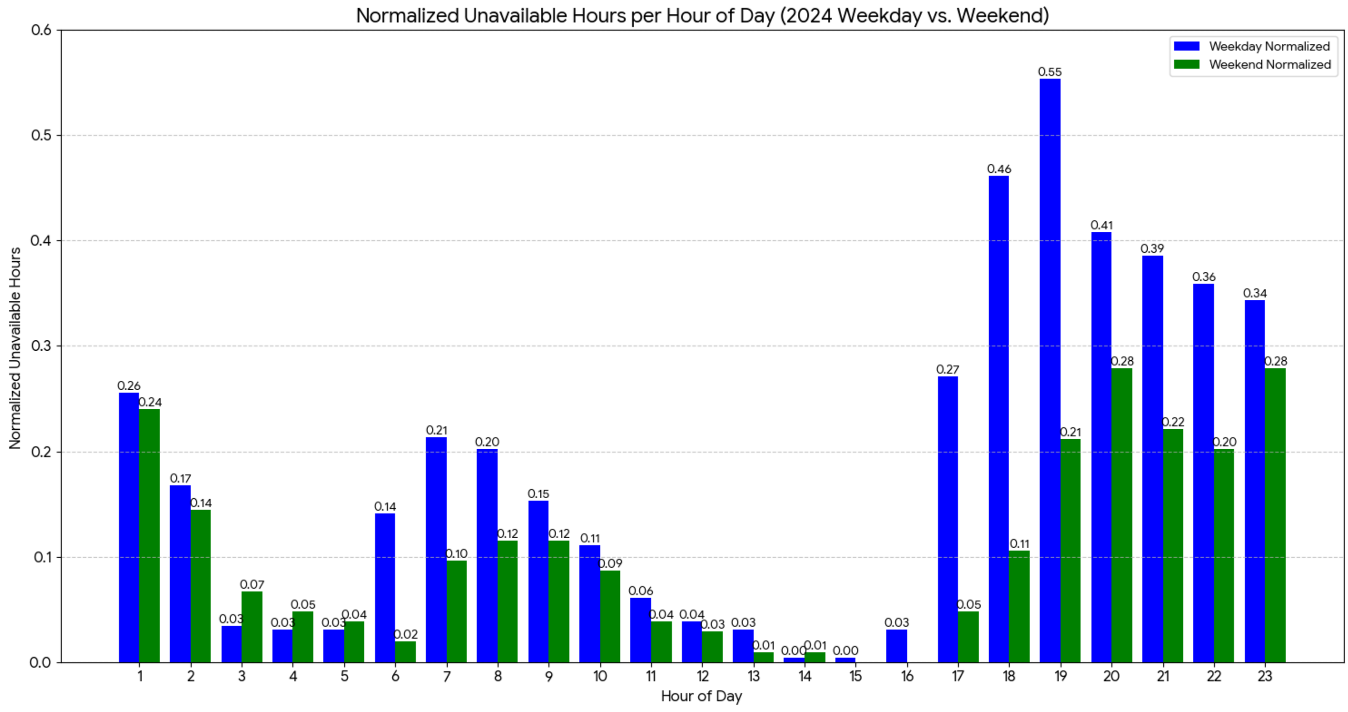

Figure 3.1.6 Normalized Unavailable Hours per Hour of Day (2024 Weekday vs. Weekend)

Figure 3.1.5 shows the analysis of normalized unavailable hours reveals clear differences between weekdays and weekends in terms of cross-border electricity availability. On weekdays, unavailability peaks sharply during the evening hours between 18:00 and 22:00, with the highest value reaching 0.55 at 19:00, reflecting India's elevated domestic demand during its evening peak load. In contrast, weekends show significantly lower unavailability, with peak values not exceeding 0.28, indicating that reduced industrial and commercial activity leaves more capacity for export. Both weekdays and weekends, however, exhibit very low unavailability between 10:00 and 15:00, often approaching zero, which can be attributed to lower demand and higher renewable generation, particularly from solar. Overall, the comparison demonstrates that Sri Lanka faces greater challenges in securing imports during weekday evenings, whereas weekends provide more favorable conditions for cross-border power purchases, especially in the midday period.

The second approach evaluates the unavailability probabilities based on each month and hour of the day throughout the year.

Table 3.1 Unavailable Probability by Month and Hour of the Day

Hour	Jan	Feb	Mar	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec
1	0	0	0.06452	0.6	0.58065	0.76667	0.58065	0.16129	0.12879	0.09677	0	0
2	0	0	0	0.43333	0.32258	0.5	0.41935	0.06452	0.06364	0.03226	0	0
3	0	0	0	0.2	0.06452	0.33333	0.25806	0.03226	0	0	0	0
4	0	0	0	0.03333	0.03226	0.13333	0.19355	0	0	0	0	0
5	0	0	0	0.06667	0	0.13333	0.22581	0	0	0	0	0
6	0	0	0	0.16667	0	0.13333	0.12903	0	0	0	0	0
7	0.3871	0.31034	0.09677	0.3	0.03226	0.13333	0.16129	0.03226	0.03182	0	0	0.03226
8	0.87097	0.55172	0.19355	0.03333	0	0.03333	0.12903	0.03226	0	0	0.03333	0.25806
9	0.93548	0.55172	0.19355	0	0	0	0.03226	0	0	0	0	0.35484
10	0.96774	0.41379	0	0	0	0	0	0	0	0	0	0.19355
11	0.83871	0.17241	0	0	0	0	0	0	0	0	0	0.06452
12	0.58065	0	0	0	0	0	0	0	0	0	0	0
13	0.25806	0	0	0	0	0	0	0	0	0	0	0
14	0.03226	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0
16	0.22581	0	0	0	0	0.03333	0	0	0	0	0	0
17	0.6129	0.10345	0	0	0.06452	0.03333	0	0.03226	0.06364	0	0.2	0.25806
18	0.83871	0.24138	0	0.06667	0	0.03333	0	0.03226	0.19242	0.25806	0.5	0.51613
19	0.80645	0.58621	0.32258	0.2	0.03226	0.03333	0.41935	0.12903	0.38636	0.48387	0.6	0.70968
20	0.77419	0.62069	0.35484	0.33333	0.41935	0.4	0.70968	0.51613	0.67424	0.54839	0.06667	0.25806
21	0.54839	0.24138	0.09677	0.33333	0.51613	0.63333	0.80645	0.51613	0.41667	0.16129	0	0
22	0.25806	0.06897	0.03226	0.46667	0.6129	0.83333	0.83871	0.45161	0.3197	0.09677	0	0
23	0	0	0.06452	0.7	0.77419	0.86667	0.83871	0.3871	0.32121	0.09677	0	0
24	0	0	0.06452	0.66667	0.77419	0.9	0.83871	0.29032	0.26667	0.03226	0	0

The table 3.1 provides how the probability of power unavailability varies by both the time of day and the season, revealing clear trends throughout the year. Unavailability is most pronounced in the early mornings and evenings, with noticeable seasonal fluctuations.

During the early morning to midday hours (7:00–12:00), unavailability is particularly high, especially in the summer months from January to May. For instance, between 8:00 and 11:00 during January to March, the probability of unavailability often exceeds 0.8–0.96, reflecting strong limitations on power imports due to India’s morning demand surge. This trend eases by mid-year, with June to August showing lower values, and by September to December, morning unavailability drops further, often falling below 0.2.

Evening hours (18:00–23:00) consistently experience high unavailability throughout the year. In the months of June to August, the period from 19:00 to 22:00 frequently records values above 0.7–0.9, indicating that this timeframe is the most constrained for imports. Even in later months like October and November, evening unavailability remains elevated, though slightly reduced to around 0.3–0.6. These patterns highlight the evening peak in India as the most critical period for Sri Lanka’s import reliability.

Nighttime and early morning hours (0:00–6:00) generally show very low unavailability, often close to zero across most months. This indicates that midnight and early morning provide a reliable window for imports, as domestic demand in India is minimal and supply margins are higher.

Seasonal patterns are also evident. From January to March, mornings experience very high unavailability, with values up to 0.96, while evenings are moderately constrained. April and May represent a transition phase, with morning unavailability still high but less severe. During June to August, the evening hours face the greatest constraints, with unavailability consistently exceeding 0.8–0.9. From September to December, conditions improve overall, with mornings showing significantly reduced unavailability, although evening hours continue to be the most constrained period of the day.

3.2 Economical Dispatch

3.2.1 Sri Lankan Power Plant Unit Price and Vulnerability to Interconnection

Table 3.2: Sri Lankan Power Plant Unit Price (LKR/kWh)

Plant Type	Energy Cost (Mn LKR)	Non Fuel Energy Cost (Mn LKR)	Capacity Cost (Mn LKR)	Total Cost of Generation (Mn LKR)	Energy Cost per Unit (LKR/kWh)	Non fuel Energy Cost per Unit (LKR/kWh)	Capacity Charge per Unit (LKR/kWh)	Cost of Electricity per Unit (LKR/kWh)
Major Hydro	0.0	0.0	38.2	38.2	0.00	0.00	2.54	2.54
Thermal - Coal	254.0	27.5	45.0	326.5	19.53	2.11	3.46	25.10
Thermal - Furnace Oil	131.3	9.4	51.7	192.4	44.69	3.19	17.58	65.47
Thermal - Diesel	0.0	1.5	19.8	21.2	0.00	0.00	0.00	0.00
Thermal - Naphtha	158.5	1.9	3.3	163.6	44.74	0.54	0.92	46.20
Wind - CEB	0.0	0.0	20.9	20.9	0.00	0.00	17.25	17.25
Wind - IPP	15.5	0.0	0.0	15.5	15.54	0.00	0.00	15.54
Solar - IPP - Ground Mounted	11.5	0.0	0.0	11.5	19.47	0.00	0.00	19.47
Solar - Roof Top	73.0	0.0	0.0	73.0	26.47	0.00	0.00	26.47
Mini Hydro	51.2	0.0	0.0	51.2	13.76	0.00	0.00	13.76
Municipal Solid Waste	20.5	0.0	0.0	20.5	39.48	0.00	0.00	39.48
Total	**715.6**	**40.2**	**178.8**	**934.6**	**16.14**	**0.91**	**4.03**	**21.08**

Sri Lanka's power generation costs vary depending on the energy source, fuel prices, and operational efficiency of power plants. The country relies on a mix of thermal (coal and oil), hydro, and renewable energy sources, each with different unit generation costs. Traditionally, hydroelectric power has been the cheapest source, with minimal operational costs.

Coal-fired power plants, such as the Norochcholai Power Station, generate electricity at a relatively lower cost compared to oil-based plants, as coal is generally cheaper than petroleum. However, fluctuations in global coal prices and transportation costs impact the overall generation cost. In contrast, oil-based power plants, often used for peak load and emergency power generation, have the highest unit generation costs due to expensive fuel imports. The reliance on costly oil-fired generation has been a major challenge for Sri Lanka’s power sector, contributing to high electricity tariffs.

Renewable energy sources like solar and wind are gradually reducing generation costs, as technological advancements and policy incentives make them more viable. However, their intermittent nature requires backup power from thermal plants, influencing overall costs. Additionally, government policies, fuel price volatility, and currency fluctuations affect Sri Lanka’s power generation expenses.

The proposed electricity interconnection between India and Sri Lanka aims to enhance energy security and grid stability by facilitating cross-border power exchange. However, this development could impact certain Sri Lankan power plants, particularly those with higher generation costs. Plants have higher per-unit generation costs, may become less competitive if lower-cost electricity is imported from India. This could lead to reduced operational hours or even potential decommissioning of these less efficient plants. Conversely, more cost-effective and efficient plants are likely to remain competitive in the market.

3.2.2 Assumptions for the Economical Dispatch

The following assumptions were considered prior to carrying out the economic dispatch analysis:

1. Even if Sri Lanka enters the Indian energy market, the market clearing price will remain unchanged, and Sri Lanka’s power requirement will not affect the Indian side.
2. In the scenario where the interconnection is available, the Indian link is assumed to be fully operational throughout the year 2024.

3.2.3 Economical Dispatch Results

The economic dispatch model was developed in Python. Demand and generation data for the year 2024 were used, and monthly hydro generation was incorporated by applying month-specific energy budgets derived from historical patterns. Renewable energy penetration levels were varied from 45% to 80% in accordance with the scenarios specified by the CEB, and the corresponding monthly solar and wind profiles were scaled consistently with these targets. Operational constraints were enforced throughout the simulations: unit-specific ramping limits were applied, plant-level minimum and maximum generation bounds were respected, and a must-run requirement of at least 600 MW was maintained for the Norochcholai (Lakvijaya) coal power plant complex. Under these assumptions and constraints, the dispatch was optimized to minimize cost while ensuring feasibility for each monthly case.

The following table presents the results of the economic dispatch carried out for a dry season, during the time interval from 00:00 a.m. to 01:00 a.m. The dispatch has been simulated for two cases: with the Indian interconnection and without the Indian interconnection.

Table 3.3: Economical Dispatch Results

Plant	**With Link**	**Without Link**
Victoria	81.86	81.86
Kotmale	49.78	49.78
Upper Kotmale	45.25	45.25
Randenigala	44.25	44.25
Samanalawewa	44.81	44.81
New Laxapana	33.19	33.19
Kukule	35.07	35.07
Polpitiya	30.42	30.42
Canyon	28.76	28.76
Rantambe	22.13	22.13
Wimalasurendra	21.01	21.01
Old Laxapana	20.47	20.47
Bowathenna	19.92	19.92
Ukuwela	19.36	19.36
Broadlands	17.69	17.69
Minihydro Telemetered	0	0
Biomass + W2E6	40	40
KPS(GT7)	100	100
KPS(GT)	100	100
KCCP	100	100
LVPS 1	200	200
LVPS 2	200	200
LVPS 3	200	200
Indian Link	**500**	**0**
ACE Matara	120	120
Asia Power	120	120
Sojitz Kelanitissa	160	160
West Coast	196.03	200

ACE-Embilipitiya	0	140
Sapugaskanda Station - A	0	120
Sapugaskanda Station - B	0	120
Uthuru Janani	0	60
Power Barge	0	56.03
Solar	0	0
Wind	50	50

Even in the case where the interconnection is available, full utilization does not occur at all times. Particularly during the daytime, several cases can be observed where the link remains underutilized. Therefore, in Chapter 4 (Results), the outcomes will be presented for all such cases, considering the different scenarios that were modeled in this study.

The dispatch presented above is only one example of the analyses that were carried out. In practice, thousands of dispatches were simulated, with 288 dispatches performed for each scenario, resulting in over a thousand dispatches in total. These simulations provided the basis for the results discussed in Chapter 4. Through this analysis, it was possible to determine the extent to which the overall generation cost deviates from the projections of the CEB Long-Term Generation Expansion Plan. Furthermore, the study enabled the identification of the categories of power plants most affected by the interconnection, particularly thermal, solar, and biomass plants.

3.3 Cost Calculations

ILUP = Indian Link Unit Price as given by CEB Generation plan

P = Probability of Unavailability

$$P = \sum_{i=1}^{n} P_i$$

$$P_i = \frac{\text{Utilization of } i\text{th power plant}}{\text{Utilization of Indian link}} \times P$$

N_i = Local Power Plants which are going to replace the link

C_i = Cost of Local Power Plants which are going to replace the link

$$New\ Cost = ILUP\ \times (1 - P) + \sum_{i=1}^{n} \mathrm{PiNiCi}$$

The Indian Link Unit Price (ILUP) represents the cost per unit of electricity imported from India through the proposed power link. This price is determined by the Ceylon Electricity Board (CEB) in its generation plan and serves as the base value for comparing imported electricity with locally generated electricity. Since the Indian link is intended to provide a relatively cheap and stable source of power, the ILUP becomes a benchmark in evaluating the cost-effectiveness of the power supply system.

However, like any power infrastructure, the Indian link is subject to risks of failure or unavailability. To account for this, the parameter P is introduced, which represents the probability that the Indian link becomes unavailable. This probability is not treated as a simple single value but rather as the sum of contributions from different local power plants, denoted by P_i. Each P_i reflects the probability share of the i th local power plant stepping in to compensate when the Indian link cannot supply electricity.

The contribution of each power plant, P_i , is determined by comparing the utilization of that particular plant with the overall utilization of the Indian link. In mathematical terms, it is expressed as,

$$P_i = \frac{\text{Utilization of } i\text{th power plant}}{\text{Utilization of Indian link}} \times P$$

This ensures that plants with higher potential to replace the Indian link carry a proportionally larger share of the unavailability risk. For example, if a particular local plant has a capacity or utilization close to that of the link, it will have a larger role in compensating for outages compared to smaller plants.

Two other parameters play a key role in this analysis: N_i and C_i . Here, N_i refers to the local power plants that are designated as backup providers when the Indian link is down, while C_i refers to the cost of operating those plants. Since local generation often involves higher costs such as fuel for thermal power plants, these values capture the economic burden of relying on local plants during link outages.

Combining these elements, the formula for New Cost is introduced,

$$New\ Cost = ILUP\ \times (1 - P) + \sum_{i=1}^{n} \text{PiNiCi}$$

This expression calculates the expected cost of electricity under both normal and failure conditions. The first term, ILUP×(1−P) represents the cost of importing power from India weighted by the probability that the link remains available. The second term, captures the expected additional cost when the Indian link fails and local plants are used instead. Each local plant contributes to this cost based on its probability share P_i, its participation in replacement (N_i), and its operating cost (C_i).

In essence, this model provides a more realistic measure of the effective electricity cost by balancing the advantage of cheaper imported electricity with the backup costs incurred when the Indian link is unavailable. It reflects the trade-off between dependence on external supply and reliance on local generation capacity, thereby allowing policymakers and engineers to make better informed decisions on energy planning and cost optimization.

Example: In the month of **March from 8.00 a.m. to 9.00 a.m.** the 500 MW of power delivered by the Indian link is replaced by thermal, bio mass and solar power plants when the Indian link is unavailable.

By economic dispatch, the power delivered by each type of plant is calculated as follows.

- Thermal = 477.99 MW
- Bio Mass = 22.01 MW

The unit prices of those plant types were taken as follows.

- Thermal = Rs.55.835
- Bio Mass = Rs.39.48

The unavailable probability of the Indian link is **0.193548** and the Indian Link unit price is given as Rs.32.16.

Hence, the new cost can be calculated as,

$$\boldsymbol{New\ Cost = 32.16\ \times (1 - 0.193548) + 0.193548 \times 55.835 \times \frac{477.99}{500} + 0.193548 \times 39.48 \times \frac{22.01}{500}}$$

$$\boldsymbol{New\ Cost = Rs.36.6029}$$

3.4 Economical Effect on Sri Lanka

After preparing the cost tables for each scenario, the next step is to estimate the economic impact on individual power plants. To accurately determine the extent of this impact, parameters such as plant factors, standby costs, and other operational details would need to be incorporated into the analysis. Ideally, the economic dispatch model should also include more realistic plant-specific parameters to improve accuracy. However, due to data access restrictions, such detailed information was not available, and therefore precise numerical results could not be produced within this study.

If such data were available, it would have been possible to calculate the overall profit to the country by comparing the system cost with and without the interconnection link. Furthermore, by incorporating the construction and maintenance costs of the interconnection, an estimation of the payback period could be made, along with Net Present Value (NPV) calculations to assess the long-term financial viability of the project. Thus, while this report outlines the framework for such an evaluation, the lack of necessary resources limited the ability to generate exact financial indicators.

CHAPTER 4

Results

In this chapter, the results for Scenario 1 and Scenario 4 are presented in detail. Similar analyses can also be carried out for Scenarios 2, 3, and 5 following the same methodology. Moreover, it is important to note that the study is not limited to these five cases alone. In reality, a wide range of possible scenarios exist depending on variations in renewable penetration levels, load growth, fuel price fluctuations, and interconnection availability. Each of these scenarios can be analyzed in a similar manner to obtain a comprehensive understanding of the cost implications and the impact on individual power plants within the Sri Lankan power system.

4.1 Scenario 1: Cost with 350 MW of renewable energy (300 MW solar, 50 MW wind), with and without a 500 MW interconnection.

Table 2.1 presents the average unit cost of the Indian interconnection per kWh. Based on this, an economic dispatch was carried out with the Indian link, and it was observed that the link was fully utilized. This outcome is primarily due to the comparatively lower renewable capacity considered in this scenario, as rooftop solar was not included in the analysis. As described in Section 3.2, the economic dispatch was simulated 288 times for Scenario 1 with the link, and again 288 times without the link. The results indicated that the interconnection effectively replaced 500 MW of thermal power generation. Subsequently, cost calculations were performed while also accounting for the unavailability of the link, following the methodology outlined in Section 3.3.

Table 4.1 presents the updated cost table for Scenario 1 (*Cost with 350 MW of renewable energy [300 MW solar, 50 MW wind], with and without a 500 MW interconnection*). Figures 4.1 and 4.2 illustrate the comparison between the CEB-proposed cost per kWh and the updated cost for Scenario 1 in the form of heatmaps.

Table 4.1: Updated Cost for Scenarios

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	9.51	11.73	36.58	58.176	53.467742	59.829333	50.033226	29.254194	30.48257576	20.05548389	15.78	13.05
2	9.18	11.31	31.74	54.669667	43.505484	50.77	40.932258	22.09871	24.55845455	16.06129033	14.97	12.33
3	8.88	10.89	27.84	49.48	32.53871	42.706667	31.397742	18.645161	19.71	13.65	14.46	11.82
4	8.82	10.68	24.81	45.144667	29.474194	32.872667	27.024194	16.29	18.18	13.05	14.13	11.76
5	9.12	11.16	25.14	45.157333	27.84	34.536667	28.171613	16.98	18.72	13.65	14.82	12.69
6	11.16	13.98	33.57	48.458333	28.05	33.184667	26.180968	22.92	23.01	15.57	17.58	15.84
7	34.593871	38.006897	51.325161	51.525	28.022581	30.636667	29.933548	27.093548	30.50368182	17.91	20.55	24.74193547
8	59.04	53.681034	56.032258	41.867667	21.96	19.943667	27.487419	23.841935	23.4	17.4	25.10566667	42.9051613
9	62.188387	50.292069	38.516129	35.37	18.12	14.31	18.209677	17.46	17.43	14.94	22.2	44.60645162
10	63.607742	41.581034	28.53	34.44	18	13.29	14.88	16.02	15.57	13.86	21.39	38.32258065
11	57.796774	31.044138	29.94	34.8	19.2	14.61	14.1	14.88	14.91	13.35	20.07	31.36
12	45.252581	21.87	28.26	33.84	20.82	15.87	13.62	14.7	14.97	12.72	19.14	24.51
13	28.214839	18.36	26.7	30.93	20.76	16.86	13.32	13.77	15	12.15	17.58	20.64
14	14.551603	14.31	22.38	28.5	21.6	17.55	12.78	12.9	14.07	11.67	16.74	17.55
15	12.09	13.23	25.83	33.6	25.92	21.72	13.8	14.43	16.32	12.51	17.61	18.66
16	24.803871	14.16	30.06	38.16	29.7	27.251667	16.29	16.77	19.56	13.71	18.9	21.24
17	45.470968	22.270345	36.48	40.83	31.275806	24.583667	17.07	20.3	24.19327273	15.27	29.41600001	37.7635484
18	57.535484	33.486897	35.82	43.533333	27.93	21.944667	17.79	20.416129	32.22857576	31.33096774	46.27	49.55967741
19	57.540645	50.641379	51.309355	48.376	29.880645	23.974667	43.109677	32.504194	47.79363636	49.93935483	53.31599999	57.17290323
20	55.362581	50.984483	55.135484	52.206667	47.046452	48.842	57.852258	52.608065	58.69007576	51.36129032	28.04933333	40.79064517
21	43.205161	30.778621	41.055484	51.246667	49.980645	55.213667	60.467097	52.158065	49.41333333	28.39870966	20.79	21.75
22	27.591613	20.068276	36.587097	54.669333	54.378065	61.246667	61.179032	49.87	44.55689394	22.71096775	19.41	18.63
23	12.3	14.19	36.130968	59.225	59.156129	62.153333	61.009677	46.435161	43.09551515	21.49161291	19.44	15.78
24	10.44	12.42	36.88871	59.253333	59.095161	62.784	60.419355	39.45871	39.35533333	17.10645162	16.77	14.04

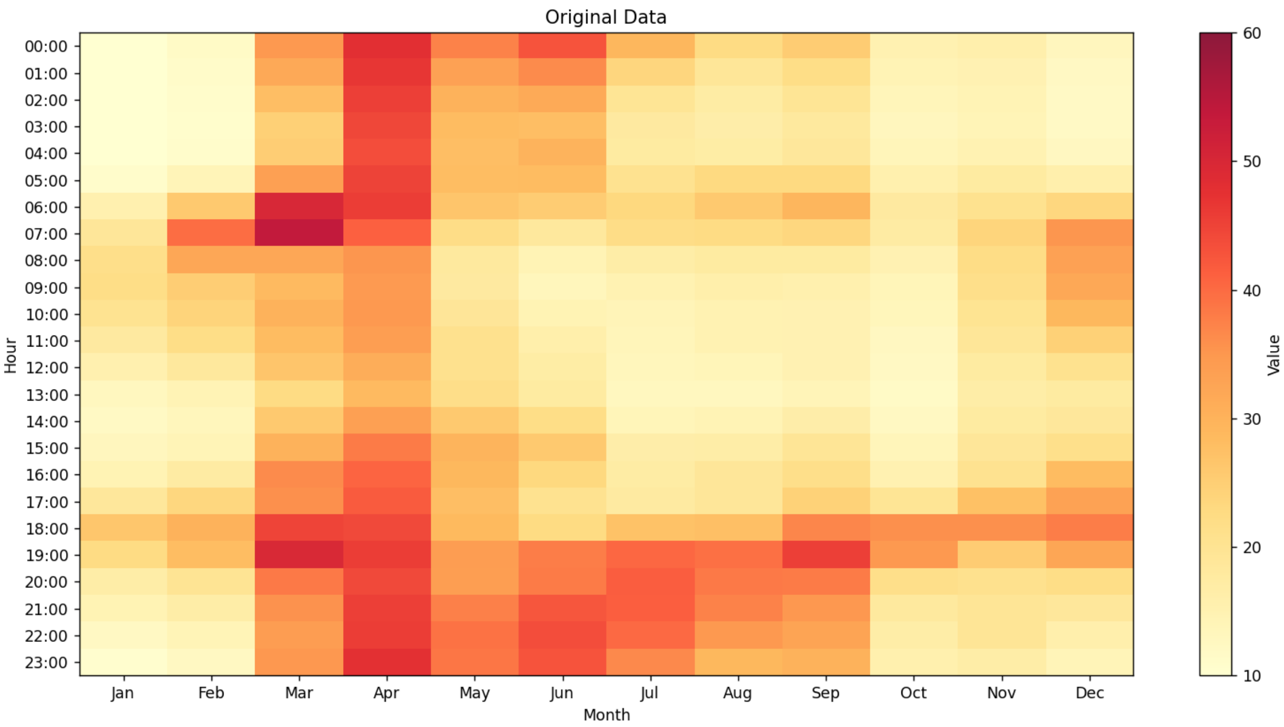

Figure 4.1: CEB-proposed cost per kWh

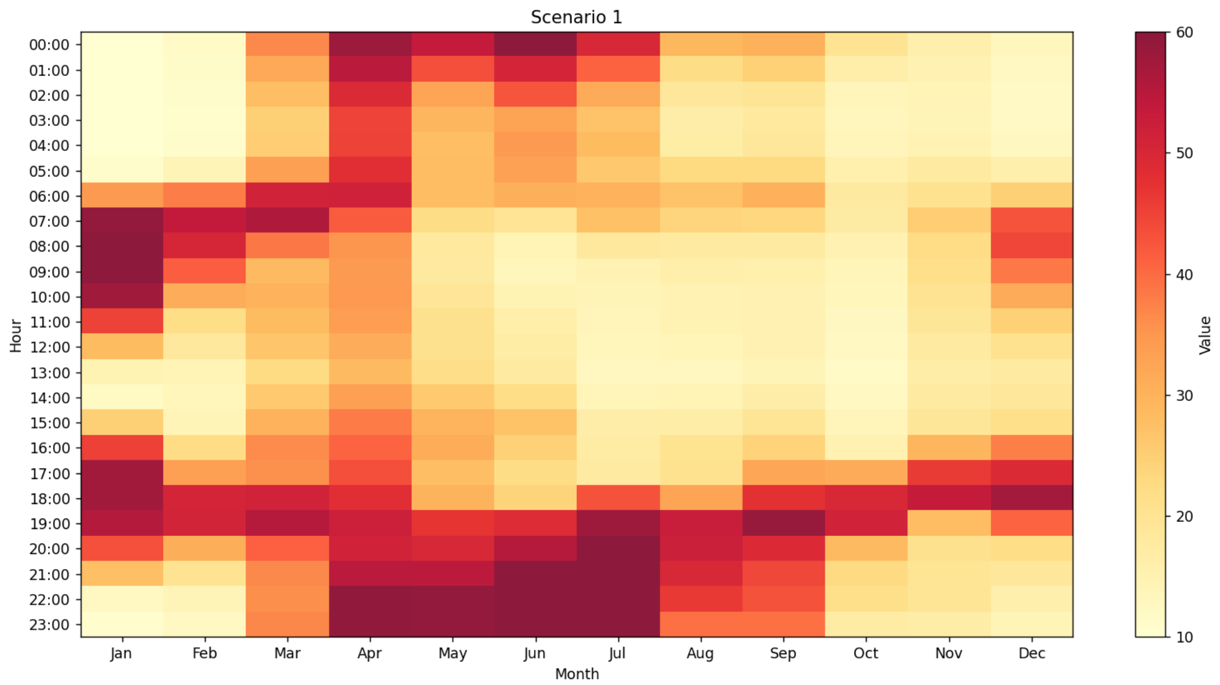

Figure 4.2: Scenario 1 updated Cost Heatmap

4.2 Scenario 4: Cost with 70% renewable energy from 2030 onwards, with and without a 500 MW HVDC interconnection.

In this scenario, the CEB has assumed that renewable energy penetration will increase to 70% by 2030, with a peak demand of 2600 MWh. An economic dispatch was first carried out with the Indian interconnection. Unlike Scenario 1, however, the link was not fully utilized. This is largely due to the availability of cheaper renewable energy sources within the system, which reduces reliance on imported electricity.

The dispatch was then repeated without the link in order to determine which power plants would be dispatched in its absence. The results showed that biomass, thermal, and solar plants predominantly entered the generation mix to meet demand. Based on this, the costs and unavailabilities of these plants were factored into the calculation of the updated cost structure for Scenario 4.

Table 4.2 presents the revised cost table for this scenario, while Figure 4.3 illustrates the updated cost distribution in the form of a heatmap. By comparing Figure 4.3 with the baseline heatmap presented in Figure 4.1, the cost variations introduced by the interconnection can be clearly identified. Furthermore, the analysis reveals that solar, thermal, and biomass plants are the most affected by the presence of the interconnection. Table 4.4 provides a detailed breakdown of the utilization levels of these plants in the absence of the link.

The key observation from Scenario 4 is that if the HVDC interconnection is implemented in the near future, the economic viability of certain domestic plants particularly thermal, solar, and biomass could be adversely affected due to reduced dispatch opportunities.

Table 4.2: Cost Table for Scenario 4

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	9.51	11.73	35.9887097	52.677	48.146129	52.8028333	44.7116129	27.7759677	29.30223485	19.1685484	15.78	13.05
2	9.18	11.31	31.74	50.6981667	40.5490323	46.1875	37.088871	21.5074194	23.97522727	15.76564517	14.97	12.33
3	8.88	10.89	27.84	47.647	31.9474194	39.6516667	29.0325806	18.3495161	19.71	13.65	14.46	11.82
4	8.82	10.68	24.81	44.8391667	29.1785484	31.6506667	25.2503226	16.29	18.18	13.05	14.13	11.76
5	9.12	11.16	25.14	44.5463333	27.84	33.3146667	26.1020968	16.98	18.72	13.65	14.82	12.69
6	11.16	13.98	33.57	46.9308333	28.05	31.9626667	24.9983871	22.92	23.01	15.57	17.58	15.84
7	31.046129	35.1625862	50.4382258	48.7755	27.7269355	29.4146667	28.4553226	26.7979032	30.21206818	17.91	20.55	24.44629031
8	51.0575806	48.6244828	54.2583871	41.5621667	21.96	19.6381667	26.3048387	23.5462903	23.4	17.4	24.73833243	39.78301017
9	21.42	45.2355172	36.6029135	35.37	18.12	14.31	17.4493114	17.46	17.43	14.94	22.2	33.39
10	21.84	37.7886207	28.53	34.44	18	13.29	14.88	16.02	15.57	13.86	21.39	31.92
11	20.34	28.8275074	29.94	34.8	19.2	14.61	14.1	14.88	14.91	13.35	20.07	29.04
12	17.91	21.87	28.26	33.84	20.82	15.87	13.62	14.7	14.97	12.72	19.14	24.51
13	15.42	18.36	26.7	30.93	20.76	16.86	13.32	13.77	15	12.15	17.58	20.64
14	13.0829019	14.31	22.38	28.5	21.6	17.55	12.78	12.9	14.07	11.67	16.74	17.55
15	12.09	13.23	25.83	33.6	25.92	21.72	13.8	14.43	16.32	12.51	17.61	18.66
16	22.2326139	14.16	30.06	38.16	29.7	26.9461667	16.29	16.77	19.56	13.71	18.9	21.24
17	39.8537097	21.3222414	36.48	40.83	30.6845161	24.2781667	17.07	20.0043548	23.61004545	15.27	27.58300001	35.3983871
18	49.8487097	31.2746552	35.82	42.9223333	27.93	21.6391667	17.79	20.1204839	30.46500758	28.96580645	41.6875	44.82935483
19	50.1495161	45.2687931	48.3529032	46.543	29.585	23.6691667	39.2662903	31.3216129	44.25261364	45.50467741	47.817	50.66870968
20	48.2670968	45.2958621	51.8833871	49.1516667	43.2030645	45.176	51.3480645	47.8777419	52.51064394	46.33532258	27.43833333	38.42548388
21	38.1791935	28.5663793	40.1685484	48.1916667	45.2503226	49.4091667	53.0759677	47.4277419	45.59458333	26.92048386	20.79	21.75
22	25.2264516	19.4362069	36.2914516	50.3923333	48.7608065	53.6091667	53.4922581	45.7309677	41.62687121	21.82403227	19.41	18.63
23	12.3	14.19	35.5396774	52.8095	52.0606452	54.2103333	53.3229032	42.8874194	40.15160606	20.60467743	19.44	15.78
24	10.44	12.42	36.2974194	53.1433333	51.9996774	54.5355	52.7325806	36.7979032	36.91133333	16.81080646	16.77	14.04

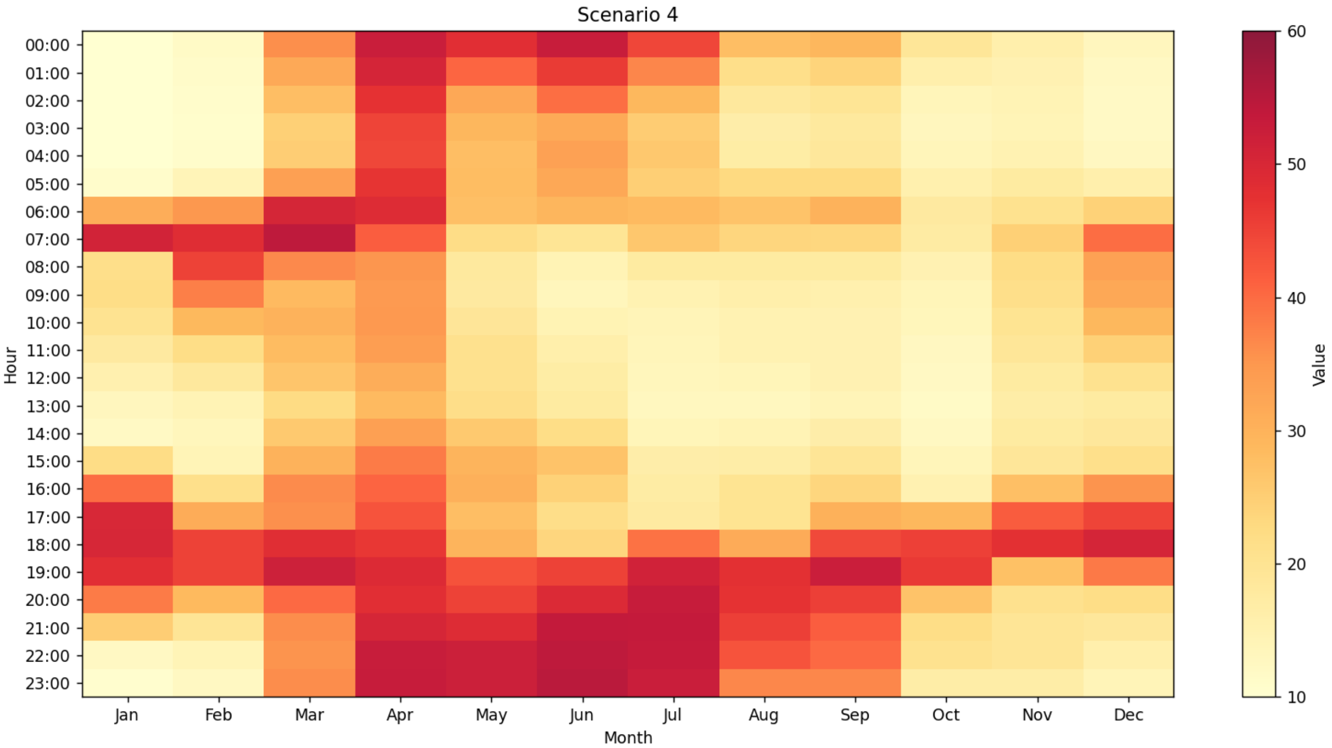

Figure 4.3: Scenario 4 Updated Cost Heatmap

Table 4.3: Utilization of Thermal, Solar and Biomass Plants in the Absence of the Link.(Jan to June)

Hour	Jan			Feb			Mar			Apr			May			Jun		
	Thermal	Solar	Bio Mass	Thermal	Solar	Bio Mass	Therma	Solar	Bio Ma	Therm	Solar	Bio Ma	Thermal	Solar	Bio Ma	Therm	Solar	Bio Mass
1	500	0	0	353.61	0	0	339.5	0	0	500	0	0	500	0	0	500	0	0
2	500	0	0	353.61	0	0	339.5	0	0	500	0	0	500	0	0	500	0	0
3	500	0	0	353.61	0	0	339.5	0	0	500	0	0	500	0	0	500	0	0
4	500	0	0	353.61	0	0	339.5	0	0	500	0	0	500	0	0	500	0	0
5	500	0	0	353.61	0	0	339.5	0	0	500	0	0	500	0	0	500	0	0
6	500	0	0	353.61	0	0	339.5	0	0	500	0	0	500	0	0	500	0	0
7	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
8	254.422	0	0	500	0	0	500	0	0	500	0	0	485.56	0	14.44	500	0	0
9	0	0	0	463.89	0	0	478	0	22.01	294	0	40	199.73	260	40	224.4	235.6	40
10	0	0	0	259.72	0	0	273.8	0	40	89.4	0	40	0	464	35.56	20.23	439.8	40
11	0	0	0	137.22	0	40	151.3	0	40	6.86	0	0	0	500	0	0	500	0
12	0	0	0	96.39	0	40	110.5	0	40	0	0	0	0	0	0	0	500	0
13	0	0	0	137.22	200.27	40	151.3	0	40	6.86	0	0	0	0	0	0	500	0
14	0	500	0	259.22	200.27	40	273.8	0	40	89.4	0	40	0	0	35.56	20.23	439.8	40
15	0	491.41	8.5886	463.89	0	36.11	478	0	22.01	294	0	40	199.73	0	40	224.4	0	40
16	0	254.42	40	500	0	0	500	0	0	500	0	0	485.56	0	14.44	500	0	0
17	500	0	0	353.61	0	0	500	0	0	500	0	0	500	0	0	500	0	0
18	500	0	0	353.61	0	0	339.5	0	0	500	0	0	500	0	0	500	0	0
19	500	0	0	353.61	0	0	339.5	0	0	500	0	0	500	0	0	500	0	0
20	500	0	0	353.61	0	0	339.5	0	0	500	0	0	500	0	0	500	0	0
21	500	0	0	353.61	0	0	339.5	0	0	500	0	0	500	0	0	500	0	0
22	500	0	0	353.61	0	0	339.5	0	0	500	0	0	500	0	0	500	0	0
23	500	0	0	353.61	0	0	339.5	0	0	500	0	0	500	0	0	500	0	0
24	500	0	0	353.61	0	0	339.5	0	0	500	0	0	500	0	0	500	0	0

Table 4.4: Utilization of Thermal, Solar and Biomass Plants in the Absence of the Link. (Jul to Dec)

July			Aug			Sep			Oct			Nov			Dec		
Thermal	Solar	Biomass	Thermal	Solar	Biomass	Thermal	Solar	Biomass	Thermal	Solar	Biomass	Thermal	Solar	Biomass	Thermal	Solar	Biomass
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	350.1	0	40	500	0	0	312.66	0	40	183.02	0	40
279.91	180	40	249.82	210	40	64.27	396	40	257.74	202	40	26.83	0	40	0	0	0
75.743	384	40	45.653	414	40	0	500	0	53.573	406	40	0	0	0	0	0	0
0	500	0	0	500	0	0	500	0	0	500	0	0	0	0	0	0	0
0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	0	0
0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	0	0
75.743	384	40	45.653	414	40	0	500	0	53.573	406	40	0	500	0	0	500	0
279.91	180	40	249.82	210	40	64.27	396	40	257.74	202	40	26.83	433	40	0	500	0
500	0	0	500	0	0	350.1	0	40	500	0	0	312.66	147	40	223.02	0	40
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0
500	0	0	500	0	0	500	0	0	500	0	0	500	0	0	500	0	0

CHAPTER 5

Discussion

The results from the economic dispatch simulations across various scenarios highlight the substantial benefits of the Indo-Lanka power grid interconnection, particularly in reducing Sri Lanka's reliance on high-cost thermal generation. In Scenario 1, with limited renewable integration (350 MW), the interconnection fully displaces 500 MW of thermal power, leading to updated unit costs that are notably lower than the CEB's projections when accounting for unavailability probabilities. This aligns with the literature on cross-border electricity trade (CBET), as discussed in Section 2.1, where interconnections like India's links with Bhutan and Nepal have optimized resource allocation and lowered costs by leveraging surplus generation. However, the heatmap comparisons (Figures 4.1 and 4.2) reveal seasonal and hourly variations, with higher unavailability during India's peak evening hours (18:00–22:00), underscoring the need for robust backup strategies to mitigate risks during these periods.

In contrast, Scenario 4, assuming 70% renewable penetration by 2030, demonstrates partial utilization of the interconnection due to the abundance of cheaper domestic renewables, such as solar and wind. This results in underutilization during daytime hours, as shown in Table 4.4, where biomass, thermal, and solar plants see increased dispatch in the absence of the link. While this supports the project's role in enhancing grid efficiency and sustainability echoing global trends in regional power integration (e.g., Wijayatunga et al., 2015) it also raises concerns about the economic viability of local plants. Thermal plants like ACE-Embilipitiya and Sapugaskanda face reduced operational hours, potentially leading to stranded assets and financial losses for independent power producers (IPPs). The updated cost heatmaps (Figure 4.3) indicate that while overall system costs decrease, the interconnection could exacerbate vulnerabilities for these plants, especially under high unavailability probabilities derived from IEX real-time market data.

Despite these advantages, the analysis is constrained by several limitations, including the assumptions of unchanged market clearing prices upon Sri Lanka's entry into the Indian market and the lack of detailed plant-specific data on factors like standby costs and ramping limits. These simplifications may overestimate savings, as real-world scenarios could involve transmission constraints or geopolitical factors not fully modeled here. Furthermore, the probability-based unavailability assessment, while innovative, relies on historical IEX data from 2024, which may not capture future shifts in India's energy mix or climate-induced variations in renewables. Overall, the findings affirm the interconnection as a strategic enabler for affordable energy trade, but emphasize the importance of policy measures such as compensation for affected IPPs and hybrid dispatch models to balance economic gains with equitable impacts on Sri Lanka's power sector.

CHAPTER 6

Conclusion

This study comprehensively evaluated the technical and economic implications of establishing an Indo–Lanka power grid interconnection using a combination of availability analysis, economic dispatch modeling, and cost assessments under multiple renewable energy penetration scenarios. The results demonstrate that the proposed HVDC link offers significant potential for reducing Sri Lanka's dependence on costly thermal generation, thereby lowering overall system costs and enhancing grid reliability.

In lower renewable penetration scenarios, the interconnection was found to be fully utilized, effectively displacing high-cost thermal generation and contributing directly to substantial cost savings. Under higher renewable penetration scenarios, the utilization of the interconnection declined during daytime hours due to the availability of cheaper domestic solar and wind generation. However, even in these cases, the link provided critical flexibility during peak demand periods and seasonal variations, confirming its value as a stabilizing and cost-optimizing resource.

The analysis also highlighted important risks and challenges. The probability of unavailability, particularly during India's peak evening hours, poses operational vulnerabilities that require robust backup planning and careful integration into Sri Lanka's dispatch strategy. Moreover, the reduced competitiveness of certain local power plants especially thermal, biomass, and independent power producers raises concerns about stranded assets and financial sustainability for domestic generators. These outcomes emphasize the need for balanced policy measures, such as compensation frameworks, hybrid dispatch models, and strategic diversification of the local energy mix, to ensure that the benefits of cross-border trade are equitably shared.

Overall, the Indo–Lanka interconnection emerges as a strategic enabler of affordable, reliable, and sustainable energy for Sri Lanka. Beyond cost reduction, it strengthens regional energy security, promotes market integration, and supports the long-term transition toward a high-renewable power system. While the economic and operational advantages are clear, successful implementation will depend on addressing uncertainties in availability, establishing fair market mechanisms, and aligning national policies with regional cooperation goals. If these measures are undertaken, the interconnection has the potential to deliver lasting economic and environmental benefits to both Sri Lanka and India.

CHAPTER 7

Future Work

In future work, collaboration with government entities such as the Ceylon Electricity Board (CEB) and the Public Utilities Commission of Sri Lanka (PUCSL) could facilitate access to restricted data on plant-specific parameters, including standby costs, plant factors, and detailed operational details, which were unavailable during this study due to data access limitations. This would enable the development of a more refined economic dispatch model, allowing for precise quantification of the interconnection's economic impact on individual power plants, calculation of overall national profits by comparing system costs with and without the link, estimation of the investment payback period, and thorough Net Present Value (NPV) analyses to evaluate long-term financial viability. Furthermore, incorporating real-time IEX data for all 35,040 annual supply-demand curves currently impractical due to resource constraints along with dynamic factors like transmission losses, geopolitical risks, and varying renewable penetration levels beyond the analyzed scenarios, will provide a comprehensive framework for optimizing cross-border energy trade and informing policy decisions.

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Appendix

Economic Dispatch

```
import pandas as pd

def economic_dispatch(demand, indian_link_price, month, hour):
    """
    Perform economic dispatch with monthly hydro capacities, seasonal constraints,
    and hourly solar power variation.
    Season is automatically determined based on month.
    Hour should be 1-24 (1 = 1am, 12 = noon, 24 = midnight).
    """
    # Validate hour input
    if hour < 1 or hour > 24:
        raise ValueError("Hour must be between 1 and 24")

    # Determine season based on month
    month = month.lower()
    dry_season_months = ['dec', 'jan', 'feb', 'mar', 'apr']
    if month in dry_season_months:
        season = 'dry'
    else:
        season = 'wet'

    monthly_data = {
        'jan': {
            'Victoria': 163.9554, 'Kotmale': 73.65121, 'Upper Kotmale': 67.05712, 'Randenigala': 95.95027,
            'Samanalawewa': 99.0373, 'New Laxapana': 67.03461, 'Kukule': 37.5541, 'Polpitiya': 54.6418,
            'Canyon': 20.78226, 'Rantambe': 46.10954, 'Wimalasurendra': 26.58165, 'Old Laxapana': 36.49227,
            'Bowathenna': 22.67977, 'Ukuwela': 15.6959, 'Broadlands': 11.68817, 'Uma Ora': 0
        },
        'feb': {
            'Victoria': 54.73, 'Kotmale': 33.27, 'Upper Kotmale': 30.25, 'Randenigala': 29.58,
            'Samanalawewa': 29.96, 'New Laxapana': 22.19, 'Kukule': 23.44, 'Polpitiya': 20.34,
            'Canyon': 19.23, 'Rantambe': 14.79, 'Wimalasurendra': 14.05, 'Old Laxapana': 13.68,
            'Bowathenna': 13.32, 'Ukuwela': 12.95, 'Broadlands': 11.83
        },
        'mar': {
            'Victoria': 52.49, 'Kotmale': 31.91, 'Upper Kotmale': 29.01, 'Randenigala': 28.37,
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    'Samanalawewa': 28.72, 'New Laxapana': 21.28, 'Kukule': 22.49, 'Polpitiya': 19.50,
    'Canyon': 18.44, 'Rantambe': 14.18, 'Wimalasurendra': 13.48, 'Old Laxapana': 13.12,
    'Bowathenna': 12.77, 'Ukuwela': 12.41, 'Broadlands': 11.34
  },
  'apr': {
    'Victoria': 81.86, 'Kotmale': 49.78, 'Upper Kotmale': 45.25, 'Randenigala': 44.25,
    'Samanalawewa': 44.81, 'New Laxapana': 33.19, 'Kukule': 35.07, 'Polpitiya': 30.42,
    'Canyon': 28.76, 'Rantambe': 22.13, 'Wimalasurendra': 21.01, 'Old Laxapana': 20.47,
    'Bowathenna': 19.92, 'Ukuwela': 19.36, 'Broadlands': 17.69
  },
  'may': {
    'Victoria': 89.64, 'Kotmale': 54.52, 'Upper Kotmale': 49.54, 'Randenigala': 48.45,
    'Samanalawewa': 49.06, 'New Laxapana': 36.34, 'Kukule': 38.40, 'Polpitiya': 33.31,
    'Canyon': 31.49, 'Rantambe': 24.22, 'Wimalasurendra': 23.01, 'Old Laxapana': 22.41,
    'Bowathenna': 21.80, 'Ukuwela': 21.20, 'Broadlands': 19.38
  },
  'jun': {
    'Victoria': 85.71, 'Kotmale': 52.13, 'Upper Kotmale': 47.38, 'Randenigala': 46.33,
    'Samanalawewa': 46.90, 'New Laxapana': 34.75, 'Kukule': 36.71, 'Polpitiya': 31.85,
    'Canyon': 30.11, 'Rantambe': 23.17, 'Wimalasurendra': 22.00, 'Old Laxapana': 21.43,
    'Bowathenna': 20.85, 'Ukuwela': 20.26, 'Broadlands': 18.53
  },
  'jul': {
    'Victoria': 76.87, 'Kotmale': 46.75, 'Upper Kotmale': 42.49, 'Randenigala': 41.55,
    'Samanalawewa': 42.07, 'New Laxapana': 31.16, 'Kukule': 32.93, 'Polpitiya': 28.56,
    'Canyon': 27.00, 'Rantambe': 20.78, 'Wimalasurendra': 19.73, 'Old Laxapana': 19.22,
    'Bowathenna': 18.70, 'Ukuwela': 18.17, 'Broadlands': 16.61
  },
  'aug': {
    'Victoria': 81.65, 'Kotmale': 49.65, 'Upper Kotmale': 45.13, 'Randenigala': 44.14,
    'Samanalawewa': 44.69, 'New Laxapana': 33.10, 'Kukule': 34.97, 'Polpitiya': 30.35,
    'Canyon': 28.70, 'Rantambe': 22.07, 'Wimalasurendra': 20.97, 'Old Laxapana': 20.42,
    'Bowathenna': 19.87, 'Ukuwela': 19.31, 'Broadlands': 17.66
  },
  'sep': {
    'Victoria': 111.21, 'Kotmale': 67.63, 'Upper Kotmale': 61.46, 'Randenigala': 60.11,
    'Samanalawewa': 60.86, 'New Laxapana': 45.08, 'Kukule': 47.64, 'Polpitiya': 41.33,
    'Canyon': 39.07, 'Rantambe': 30.06, 'Wimalasurendra': 28.56, 'Old Laxapana': 27.81,
    'Bowathenna': 27.06, 'Ukuwela': 26.31, 'Broadlands': 24.04
  },
  'oct': {
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        'Victoria': 80.39, 'Kotmale': 48.88, 'Upper Kotmale': 44.44, 'Randenigala': 43.46,
        'Samanalawewa': 44.00, 'New Laxapana': 32.59, 'Kukule': 34.44, 'Polpitiya': 29.88,
        'Canyon': 28.25, 'Rantambe': 21.73, 'Wimalasurendra': 20.65, 'Old Laxapana': 20.09,
        'Bowathenna': 19.56, 'Ukuwela': 19.02, 'Broadlands': 17.38
    },
    'nov': {
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        'Samanalawewa': 64.14, 'New Laxapana': 47.50, 'Kukule': 50.19, 'Polpitiya': 43.54,
        'Canyon': 41.17, 'Rantambe': 31.67, 'Wimalasurendra': 30.08, 'Old Laxapana': 29.29,
        'Bowathenna': 28.50, 'Ukuwela': 27.71, 'Broadlands': 25.33
    },
    'dec': {
        'Victoria': 187.5813, 'Kotmale': 101.0225, 'Upper Kotmale': 71.61324, 'Randenigala': 110.4694,
        'Samanalawewa': 41.79301, 'New Laxapana': 65.6912, 'Kukule': 34.41667, 'Polpitiya': 61.7621,
        'Canyon': 19.22917, 'Rantambe': 46.77184, 'Wimalasurendra': 27.97312, 'Old Laxapana': 47.39819,
        'Bowathenna': 21.23286, 'Ukuwela': 18.99126, 'Broadlands': 14.36492, 'Uma Ora': 53.02218
    }
}

if month not in monthly_data:
    raise ValueError("Invalid month. Use 3-letter month abbreviations (jan, feb, etc.)")

# Calculate solar power based on hour of day
def get_solar_power(hour, max_capacity=1470):
    """Returns solar power output based on hour of day (0 at night, max around noon)"""
    # Solar hours approximately 6am to 6pm (6 to 18)
    if hour < 6 or hour >= 18:
        return 0  # No solar at night

    # Create a bell curve for solar output
    # Peak at noon (hour = 12), zero at 6 and 18
    # Using a simple quadratic function for approximation
    normalized_hour = hour - 6  # Now ranges from 0 to 12
    # Quadratic that peaks at 6 (which is noon in normalized hours)
    # y = -a(x-6)^2 + max_capacity
    # At x=0 and x=12, y=0
    # So a = max_capacity / 36
    a = max_capacity / 36
    solar_output = -a * (normalized_hour - 6)**2 + max_capacity

    return max(0, solar_output)  # Ensure not negative
```

```
solar_output = get_solar_power(hour)

# Power plant data
plants = [
    # Hydro plants (will be set to monthly values)
    {"name": "Victoria", "full_capacity": 140, "cost": 2.54, "type": "hydro"},
    {"name": "Kotmale", "full_capacity": 120, "cost": 2.54, "type": "hydro"},
    {"name": "Upper Kotmale", "full_capacity": 120, "cost": 2.54, "type": "hydro"},
    {"name": "Randenigala", "full_capacity": 120, "cost": 2.54, "type": "hydro"},
    {"name": "Samanalawewa", "full_capacity": 100, "cost": 2.54, "type": "hydro"},
    {"name": "New Laxapana", "full_capacity": 88, "cost": 2.54, "type": "hydro"},
    {"name": "Kukule", "full_capacity": 80, "cost": 2.54, "type": "hydro"},
    {"name": "Polpitiya", "full_capacity": 100, "cost": 2.54, "type": "hydro"},
    {"name": "Canyon", "full_capacity": 80, "cost": 2.54, "type": "hydro"},
    {"name": "Rantambe", "full_capacity": 48, "cost": 2.54, "type": "hydro"},
    {"name": "Wimalasurendra", "full_capacity": 72, "cost": 2.54, "type": "hydro"},
    {"name": "Old Laxapana", "full_capacity": 80, "cost": 2.54, "type": "hydro"},
    {"name": "Bowathenna", "full_capacity": 60, "cost": 2.54, "type": "hydro"},
    {"name": "Ukuwela", "full_capacity": 60, "cost": 2.54, "type": "hydro"},
    {"name": "Broadlands", "full_capacity": 100, "cost": 2.54, "type": "hydro"},

    # Mini Hydro (special treatment)
    {"name": "Minihydro Telemetered", "full_capacity": 60, "cost": 13.76, "type": "mini_hydro"},

    # Thermal plants
    {"name": "Biomass + W2E6", "full_capacity": 40, "cost": 39.48, "type": "thermal"},
    {"name": "KPS(GT7)", "full_capacity": 100, "cost": 65.47, "type": "thermal"},
    {"name": "KPS(GT)", "full_capacity": 100, "cost": 65.47, "type": "thermal"},
    {"name": "KCCP", "full_capacity": 100, "cost": 65.47, "type": "thermal"},

    # LVPS plants (coal)
    {"name": "LVPS 1", "full_capacity": 300, "cost": 25.00, "type": "lvps", "min_capacity": 180},
    {"name": "LVPS 2", "full_capacity": 300, "cost": 25.00, "type": "lvps", "min_capacity": 180},
    {"name": "LVPS 3", "full_capacity": 300, "cost": 25.00, "type": "lvps", "min_capacity": 180},

    # Other plants
    {"name": "Indian Link", "full_capacity": 0, "cost": indian_link_price, "type": "interconnect"},
    {"name": "ACE Matara", "full_capacity": 120, "cost": 65.47, "type": "thermal"},
    {"name": "Asia Power", "full_capacity": 120, "cost": 65.47, "type": "thermal"},
    {"name": "Sojitz Kelanitissa", "full_capacity": 160, "cost": 65.47, "type": "thermal"},
```

```
    {"name": "West Coast", "full_capacity": 200, "cost": 65.47, "type": "thermal"},
    {"name": "ACE-Embilipitiya", "full_capacity": 140, "cost": 65.47, "type": "thermal"},
    {"name": "Sapugaskanda Station - A", "full_capacity": 120, "cost": 65.47, "type": "thermal"},
    {"name": "Sapugaskanda Station - B", "full_capacity": 120, "cost": 65.47, "type": "thermal"},
    {"name": "Uthuru Janani", "full_capacity": 60, "cost": 65.47, "type": "thermal"},
    {"name": "Power Barge", "full_capacity": 80, "cost": 65.47, "type": "thermal"},
    {"name": "Solar", "full_capacity": 1470, "cost": 19.54, "type": "renewable"},
    {"name": "Wind", "full_capacity": 50, "cost": 17.25, "type": "renewable"}
]

# Set hydro capacities based on month
for plant in plants:
    if plant["type"] == "hydro" and plant["name"] in monthly_data[month]:
        plant["available_capacity"] = monthly_data[month][plant["name"]]

    elif plant["type"] == "mini_hydro":
        if season == "dry":
            plant["available_capacity"] = 0  # Mini hydro = 0 in dry season
        else:
            # 75% capacity in wet season (midpoint of 70-80%)
            plant["available_capacity"] = plant["full_capacity"] * 0.75

    elif plant["name"] == "Solar":
        # Set solar capacity based on hour of day
        plant["available_capacity"] = solar_output

    else:
        plant["available_capacity"] = plant["full_capacity"]

# Separate LVPS plants
lvps_plants = [p for p in plants if p["type"] == "lvps"]
other_plants = [p for p in plants if p["type"] != "lvps"]

# Sort other plants by cost (cheapest first)
other_plants_sorted = sorted(other_plants, key=lambda x: x["cost"])

dispatch = {}
remaining_demand = demand
total_cost = 0
total_capacity = sum(p["available_capacity"] for p in plants)
```

```
    # First handle LVPS plants (fixed at 600MW total, with each plant at least 180MW if running)
    lvps_demand = min(remaining_demand, 600)  # Fixed 600MW instead of random
    if lvps_demand > 0:
        # Distribute among LVPS plants (each gets 200MW when running)
        for plant in lvps_plants:
            if lvps_demand >= 180:  # Check if we can meet minimum capacity
                dispatched = min(200, lvps_demand)  # Each unit gets up to 200MW
                dispatch[plant["name"]] = dispatched
                hourly_cost = dispatched * plant["cost"] * 1000
                total_cost += hourly_cost
                remaining_demand -= dispatched
                lvps_demand -= dispatched

    # Then dispatch remaining demand to other plants
    for plant in other_plants_sorted:
        if remaining_demand <= 0:
            dispatch[plant["name"]] = 0
            continue

        # Dispatch as much as possible from this plant
        dispatched = min(plant["available_capacity"], remaining_demand)
        dispatch[plant["name"]] = dispatched
        hourly_cost = dispatched * plant["cost"] * 1000
        total_cost += hourly_cost
        remaining_demand -= dispatched

    return dispatch, total_cost, plants  # Return plants list for saving to file

def run_24_hour_dispatch():
    # Fixed parameters
    demand = 2600  # MW
    month = "dec"

    # Indian Link prices for 24 hours
    indian_link_prices = [
        13.05, 12.33, 11.82, 11.76, 12.69, 15.84,
        24.74193547, 42.9051613, 44.60645162, 38.32258065, 31.36, 24.51,
        20.64, 17.55, 18.66, 21.24, 37.7635484, 49.55967741,
        57.17290323, 40.79064517, 21.75, 18.63, 15.78, 14.04
    ]
```

```
    # Prepare a list to store all dispatch results
    all_results = []

    # Run dispatch for each hour
    for hour in range(1, 25):
        indian_link_price = indian_link_prices[hour-1]
        dispatch, total_cost, plants = economic_dispatch(demand, indian_link_price, month, hour)

        # Prepare the result for this hour
        result = {
            "Hour": hour,
            "Indian_Link_Price": indian_link_price,
            "Total_Cost": total_cost,
            "Average_Cost": total_cost / (demand * 1000),
            "Unmet_Demand": demand - sum(dispatch.values())
        }

        # Add dispatch results for each plant
        for plant in plants:
            result[plant["name"]] = dispatch.get(plant["name"], 0)

        all_results.append(result)

    # Convert to DataFrame
    df = pd.DataFrame(all_results)

    # Save to Excel
    output_path = r"D:\Others\fy\For End\ED\dispatch_results_dec_without_link.xlsx"
    df.to_excel(output_path, index=False)
    print(f"Dispatch results saved to {output_path}")

if __name__ == "__main__":
    run_24_hour_dispatch()
```

Heat maps

```
import numpy as np

import matplotlib.pyplot as plt


# Data from the provided dataset

'''data_Scenario_4= [

    [9.51, 11.73, 35.98870968, 52.677, 48.14612903, 52.80283333, 44.7116129, 27.77596774, 29.30223485, 19.1685484, 15.78, 13.05],

    [9.18, 11.31, 31.74, 50.69816667, 40.54903225, 46.1875, 37.08887098, 21.50741936, 23.97522727, 15.76564517, 14.97, 12.33],

    [8.88, 10.89, 27.84, 47.647, 31.94741936, 39.65166667, 29.03258064, 18.34951612, 19.71, 13.65, 14.46, 11.82],

    [8.82, 10.68, 24.81, 44.83916667, 29.17854839, 31.65066667, 25.25032257, 16.29, 18.18, 13.05, 14.13, 11.76],

    [9.12, 11.16, 25.14, 44.54633333, 27.84, 33.31466667, 26.10209676, 16.98, 18.72, 13.65, 14.82, 12.69],

    [11.16, 13.98, 33.57, 46.93083333, 28.05, 31.96266667, 24.99838711, 22.92, 23.01, 15.57, 17.58, 15.84],

    [31.04612903, 35.16258621, 50.43822581, 48.7755, 27.72693549, 29.41466667, 28.45532257, 26.79790322, 30.21206818, 17.91, 20.55, 24.44629031],

    [51.05758065, 48.62448276, 54.2583871, 41.56216666, 21.96, 19.63816667, 26.3048387, 23.54629031, 23.4, 17.4, 24.73833243, 39.78301017],

    [21.42, 45.23551724, 36.60291346, 35.37, 18.12, 14.31, 17.44931143, 17.46, 17.43, 14.94, 22.2, 33.39],

    [21.84, 37.78862069, 28.53, 34.44, 18, 13.29, 14.88, 16.02, 15.57, 13.86, 21.39, 31.92],

    [20.34, 28.82750742, 29.94, 34.8, 19.2, 14.61, 14.1, 14.88, 14.91, 13.35, 20.07, 29.04],

    [17.91, 21.87, 28.26, 33.84, 20.82, 15.87, 13.62, 14.7, 14.97, 12.72, 19.14, 24.51],

    [15.42, 18.36, 26.7, 30.93, 20.76, 16.86, 13.32, 13.77, 15, 12.15, 17.58, 20.64],

    [13.08290195, 14.31, 22.38, 28.5, 21.6, 17.55, 12.78, 12.9, 14.07, 11.67, 16.74, 17.55],

    [12.09, 13.23, 25.83, 33.6, 25.92, 21.72, 13.8, 14.43, 16.32, 12.51, 17.61, 18.66],

    [22.23261385, 14.16, 30.06, 38.16, 29.7, 26.94616667, 16.29, 16.77, 19.56, 13.71, 18.9, 21.24],

    [39.85370968, 21.32224138, 36.48, 40.83, 30.68451613, 24.27816667, 17.07, 20.00435483, 23.61004545, 15.27, 27.58300001, 35.3983871],

    [49.84870968, 31.27465517, 35.82, 42.92233333, 27.93, 21.63916667, 17.79, 20.12048386, 30.46500758, 28.96580645, 41.6875, 44.82935483],

    [50.14951613, 45.2687931, 48.35290323, 46.543, 29.585, 23.66916667, 39.26629031, 31.32161291, 44.25261364, 45.50467741, 47.817, 50.66870968],

    [48.26709677, 45.29586207, 51.8833871, 49.15166667, 43.20306452, 45.176, 51.34806452, 47.87774193, 52.51064394, 46.33532258, 27.43833333, 38.42548388],

    [38.17919355, 28.56637931, 40.16854839, 48.19166667, 45.25032258, 49.40916667, 53.07596774, 47.42774193, 45.59458333, 26.92048386, 20.79, 21.75],

    [25.22645161, 19.4362069, 36.29145162, 50.39233333, 48.76080645, 53.60916667, 53.49225806, 45.73096773, 41.62687121, 21.82403227, 19.41, 18.63],

    [12.3, 14.19, 35.53967742, 52.8095, 52.06064517, 54.21033333, 53.32290322, 42.88741936, 40.15160606, 20.60467743, 19.44, 15.78],
```

```
    [10.44, 12.42, 36.29741935, 53.14333333, 51.99967743, 54.5355, 52.73258064, 36.79790323, 36.91133333, 16.81080646,
16.77, 14.04]
]


data_Scenario_1 = [
    [9.51, 11.73, 36.58000001, 58.17599999, 53.46774193, 59.82933333, 50.0332258, 29.25419354, 30.48257576,
20.05548389, 15.78, 13.05],
    [9.18, 11.31, 31.74, 54.66966667, 43.50548387, 50.77, 40.93225808, 22.09870968, 24.55845455, 16.06129033, 14.97,
12.33],
    [8.88, 10.89, 27.84, 49.48, 32.53870968, 42.70666667, 31.39774193, 18.64516127, 19.71, 13.65, 14.46, 11.82],
    [8.82, 10.68, 24.81, 45.14466667, 29.47419355, 32.87266667, 27.02419353, 16.29, 18.18, 13.05, 14.13, 11.76],
    [9.12, 11.16, 25.14, 45.15733333, 27.84, 34.53666667, 28.17161289, 16.98, 18.72, 13.65, 14.82, 12.69],
    [11.16, 13.98, 33.57, 48.45833333, 28.05, 33.18466667, 26.18096775, 22.92, 23.01, 15.57, 17.58, 15.84],
    [34.59387097, 38.00689655, 51.32516129, 51.525, 28.02258065, 30.63666667, 29.93354837, 27.09354837, 30.50368182,
17.91, 20.55, 24.74193547],
    [59.04, 53.68103448, 56.03225806, 41.86766666, 21.96, 19.94366667, 27.48741934, 23.84193547, 23.4, 17.4,
25.10566667, 42.9051613],
    [62.1883871, 50.29206897, 38.51612903, 35.37, 18.12, 14.31, 18.20967742, 17.46, 17.43, 14.94, 22.2, 44.60645162],
    [63.60774194, 41.58103448, 28.53, 34.44, 18, 13.29, 14.88, 16.02, 15.57, 13.86, 21.39, 38.32258065],
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    [45.47096774, 22.27034483, 36.48, 40.83, 31.27580646, 24.58366667, 17.07, 20.29999999, 24.19327273, 15.27,
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    [57.54064516, 50.64137931, 51.30935484, 48.376, 29.88064516, 23.97466667, 43.10967741, 32.50419355, 47.79363636,
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    [55.36258065, 50.98448276, 55.13548388, 52.20666667, 47.04645162, 48.842, 57.85225807, 52.60806451, 58.69007576,
51.36129032, 28.04933333, 40.79064517],
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19.44, 15.78],
    [10.44, 12.42, 36.88870967, 59.25333334, 59.0951613, 62.784, 60.41935483, 39.45870969, 39.35533333, 17.10645162,
16.77, 14.04]
]
'''


data = [
    [9.51, 11.73, 34.62, 47.94, 37.5, 42.84, 29.31, 22.38, 25.38, 15.24, 15.78, 13.05],
```

```
    [9.18, 11.31, 31.74, 46.77, 33.27, 36.54, 23.55, 19.14, 21.81, 14.43, 14.97, 12.33],
    [8.88, 10.89, 27.84, 45.6, 30.3, 31.56, 19.71, 17.1, 19.71, 13.65, 14.46, 11.82],
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    [21.42, 32.19, 32.16, 35.37, 18.12, 14.31, 16.65, 17.46, 17.43, 14.94, 22.2, 33.39],
    [21.84, 25.05, 28.53, 34.44, 18, 13.29, 14.88, 16.02, 15.57, 13.86, 21.39, 31.92],
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    [15.42, 18.36, 26.7, 30.93, 20.76, 16.86, 13.32, 13.77, 15, 12.15, 17.58, 20.64],
    [12.87, 14.31, 22.38, 28.5, 21.6, 17.55, 12.78, 12.9, 14.07, 11.67, 16.74, 17.55],
    [12.09, 13.23, 25.83, 33.6, 25.92, 21.72, 13.8, 14.43, 16.32, 12.51, 17.61, 18.66],
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    [14.55, 17.34, 36.48, 40.83, 28.95, 23.19, 17.07, 18.81, 21.42, 15.27, 20.52, 28.29],
    [18.72, 23.46, 35.82, 42, 27.93, 20.46, 17.79, 18.93, 24.42, 19.62, 27.54, 33.09],
    [26.46, 30.3, 44.79, 44.22, 28.71, 22.56, 27.3, 27.69, 36.96, 35.82, 35.79, 38.04],
    [22.32, 28.05, 49.71, 45.81, 34.08, 38.07, 40.38, 39.39, 45.63, 34.8, 25.41, 32.37],
    [16.74, 19.89, 38.49, 44.37, 33.96, 38.31, 41.58, 38.46, 38.28, 21.36, 20.79, 21.75],
    [14.58, 16.74, 35.64, 45.63, 37.56, 42.48, 41.31, 37.41, 34.95, 18.18, 19.41, 18.63],
    [12.3, 14.19, 34.14, 45.75, 39.12, 43.65, 40.26, 34.71, 32.73, 16.83, 19.44, 15.78],
    [10.44, 12.42, 34.95, 47.76, 38.85, 42.84, 36.6, 29.01, 30.03, 15.51, 16.77, 14.04]
]

# Convert data to numpy array
data = np.array(data)

# Create heatmap
plt.figure(figsize=(12, 8))
plt.imshow(data, cmap='YlOrRd', interpolation='nearest', aspect='auto', vmin=10, vmax=60, alpha=0.9)  # Lighter colors with adjusted range
plt.colorbar(label='Value')

# Set labels
plt.yticks(range(24), [f"{i:02d}:00" for i in range(24)])  # Vertical axis: 24 hours
plt.xticks(range(12), ['Jan', 'Feb', 'Mar', 'Apr', 'May', 'Jun', 'Jul', 'Aug', 'Sep', 'Oct', 'Nov', 'Dec'])  # Horizontal axis: Months
plt.ylabel('Hour')
plt.xlabel('Month')
plt.title('Original Data')
```

```
# Show plot
plt.show()
```