Journal of Innovations in Engineering Education
JIEE 2023, Vol. 6, Issue 1.

https://doi.org/10.3126/jiee.v6i1.58802

THAPATHALI CAMPUS
Institute of Engineering
Tribhuvan University

Indigenous resources contribution and influence of load curve shapes in the optimal growth of Bangladesh's electricity sector

Khem Gyanwali [a], Padam Adhikari[b,*], Sonu Khanal [c], Bikash Adhikari [d] and Debendra Bahadur Raut [a]

[a]*Department of Automobile and Mechanical Engineering, Thapathali Campus, Institute of Engineering, Tribhuvan University, Thapathali GPO Box 280, Kathmandu, Nepal*

[b] *Department of Mechanical and Aerospace Engineering, Pulchowk Campus, Institute of Engineering, Tribhuvan University, Pulchowk, Lalitpur, Nepal*

[c]*FutureWater, Wageningen, Netherlands*

[d]*Department of Environmental Science and Engineering, Kathmandu University, Dhulikhel, Kavre, Nepal*

ARTICLE INFO

Article history:

Received 26 Sep 2023
Revised 10 Nov 2023
Accepted 10 Dec 2023

Keywords:

Linear programming
Load curve
Exhaustible resources
Energy modeling
Optimization

Abstract

The diminishing natural gas resource has turned out to be a severe energy concern for Bangladesh. This study conducts a detailed evaluation of potential pathways for the development of Bangladesh's electricity sector as an emerging economy by developing a capacity expansion model capable of capturing the hourly operational characteristics of diverse power generators and storage technologies, while also identifying the optimal utilization of limited resources. The simulation results indicate that nuclear energy stands out as the most cost-effective option for achieving sustainable development goals in the absence of substantial opportunities for the widespread deployment of renewable energy sources in Bangladesh. However, a significant deployment of solar PV and the incorporation of battery storage could reduce the reliance on nuclear power, contingent on a revision of current land-use policies. The construction of cross-border transmission lines for importing surplus electricity is economically advisable and considering the load curve shape change is found to have a significant impact on the capacity mix.

1. Introduction

Approximately two-thirds of Bangladesh's total electricity production relies on the utilization of its native natural gas reserves[1]. However, the dwindling reserves of natural gas, coupled with rapidly escalating energy demand, present a significant and pressing national energy security challenge, necessitating alternative solutions. The power sector in Bangladesh is presently undergoing a transitional phase, marked by the temporary procurement of diesel-generated electricity from small-scale power producers by the government [2]. The optimal technology composition outlined in the 2016 Power Sector Master Plan [3] primarily suggests either a coal-centric approach or one with a substantial emphasis on renewable energy sources. Bangladesh, characterized by a relatively high population density and a predominant reliance on agriculture, confronts limitations in the extensive deployment of large-scale renewables [4]. Moreover, given its status as a lower income nation prone to the impacts of climate change and as a signatory to the Paris Agreement, the long-term viability of coal-based energy merits critical examination. To ensure affordable electricity access by 2030 and to fulfill the ambitious VISION2041 objective of achieving developed nation status by 2041, substantial investments in energy infrastructure are imperative for Bangladesh. In this regard, the long-term energy decisions of Bangladesh should be justified with a rigorous assessment of both economic and environmental aspects because those decisions will also influence Earth's temperature.

*Corresponding author:
adhikaripadam58@gmail.com (P. Adhikari)

Bangladesh has undertaken various initiatives to address the rising demand for energy. These initiatives encompass the improvement of imported energy infrastructure, the efficient utilization of domestic gas and coal resources, the import of electricity from neighboring nations, and the advancement of low-carbon and nuclear energy sources. To diversify its current generation mix, coal-fired power plants in Payra, Matarbari, and Rampal are under construction which will operate on imported fuel [1]. To supplement the diminishing domestic gas reserves, Bangladesh is importing LNG through longstanding contracts with Oman and Qatar. It is also constructing a 2.4 GW capacity Rooppur nuclear power plant with an expected commencement from 2024 [5]. The country has set a target to construct 3.1 GW capacity renewable power plants by 2021 but it seems difficult to materialize on time [6]. Apart from these short-term plans, Bangladesh needs to thoroughly investigate the proper selection of the technology mix where a significant increase in power generation capacity is expected by 2050.

Changes in socioeconomic status and environmental concerns are observed to exert an influence on electricity demand, resulting in fluctuations in electricity usage on an hourly, daily, monthly, and seasonal basis. Many studies focussing on decarbonizing the power sectors of developed nations assume that load curve shapes will remain consistent throughout the analysis period due to a relatively stable sectoral composition of power demand and consumption patterns. However, this assumption does not hold true for developing countries. These nations experience a shift in the sectoral composition, characterized by an increased share of industrial and service sectors as economic activity expands. This evolving sectoral composition will inevitably alter load curve shapes in the future. In practice, it is customary to estimate yearly electricity demand using a logarithmic regression model based on projected population growth and GDP, supplemented with other parameters such as electricity access rates and income elasticity of electricity consumption. These supplementary elements take into consideration the distinctive attributes of the electricity sector in emerging economies. Load curves can be projected by aggregating power demand across various sectors, including industrial, residential, transport, and services. Therefore, when conducting power sector analyses in developing countries, careful consideration of load curve shapes is imperative as it impacts technology selection. Furthermore, the depletion of exhaustible fuels like coal, gas, and oil due to increased energy consumption must be taken into account when developing long-term energy strategies, particularly in regions with limited fossil fuel reserves. In this context, Bangladesh should develop its energy policies through a comprehensive examination of its growing electricity demand, the resulting sectoral shifts and their effects on load curves, the depletion of native natural gas, the potential of intermittent renewable energy sources, the prices of imported fossil fuels, and their implications for climate change.

Numerous studies have explored the optimization of transformations within the electricity sector through the development of power sector models, with variations in approach, geographic scope, and temporal resolution, as discussed in the Refs. [7] and [8]. Energy modelers are actively striving to enhance the realism of long-term electricity sector models to better align with real-world conditions[9]. Ref. [10] assesses the future generation mix of a developed country, Japan, up to 2050 using an optimal power generation mix model, while Ref. [11] evaluates clean energy utilization in a developing country, Nepal, up to 2050. In contrast, the sole available study concentrated on power sector analysis in Bangladesh employed TIMES to examine electricity supply situations up to 2045, taking into account electricity imports and a substantial integration of renewables[12]. However, the temporal resolution in this study was simplified, assuming hourly electricity demand for a typical day of each month every five years. Notably, it did not address the implications of fluctuating load curve shapes or account for indigenous depletable fossil fuel resources within the modeling structure. This study explored a limited set of scenarios and did not explicitly incorporate electricity sector decarbonization policies. For a broader regional perspective, Ref.[13] provides a power sector analysis for the entire BBIN sub-region, while Refs. [14][15][16][17]and[18] offer an energy sector review specific to Bangladesh.

Hanioun et al. conducted a series of three consecutive investigations utilizing the MAED and MESSAGE to articulate optimal energy supply strategies for Syria [19]. Within this framework, the MAED model was applied to estimate energy and electricity demand [20], as well as to construct Syrian hourly load curves [21]. Past data pertaining to hourly electricity consumption across diverse sectors was used for the determination of hourly, daily, and seasonal demand coefficients in the analysis. Various models have been developed for forecasting electricity demand in the short, medium, and long term, spanning country, regional, and sectoral levels. These models employ diverse methodologies, including statistical techniques like regression models [22] time series models[23], and computational intelligence models such as artificial neural networks [24] and fuzzy neural networks [25]. Detailed assessments of electricity demand forecasting can be found in Refs.[26]

and [27]. To illustrate, a regression model based on governing parameters was employed to estimate the hourly power demand of commercial and residential sectors in three U.S. cities [28]. In Norway, the electricity demand of the service sector for each hour was calculated, taking into account factors like floor space, building age, day type, temperature influences, energy label data, and hourly metering [29]. In Turkey, a linear model was utilized to forecast hourly demand based on historical data from the previous three years [30]. Additionally, when predicting hourly electricity demand across various sectors in West African countries, several factors related to weather, social conditions, economics, technology, and calendars were considered [31]. It's worth noting that many of these studies rely on past data for projecting upcoming load curves, which presents a challenge for numerous emerging economies.

In light of this context, this research presents a capacity expansion model designed to evaluate the optimal growth of the power sector, taking into account the influence of load curve characteristics on the technology combination, along with the optimal utilization of indigenous resources. The projection of power demand is accomplished through the application of a logarithmic regression model reliant on population and GDP data. Simultaneously, the shape of the future load curve is projected using annual power demand figures and the proportion of electricity utilizing sectors within the total demand, incorporating daily and hourly coefficients from a base year. The model incorporates constraints related to production capacity and the depletion of finite fuel reserves, while also integrating production cost curves to determine the optimal exploitation of domestic resources and fuel pricing. Various technical parameters constraints are employed for the operational attributes, commitments, and maintenance schedules of power plants. Furthermore, the electricity output derived from renewable sources and hydropower is controlled based on historical availability factors. Notably, sodium-sulfur (NaS) battery technology is considered as a means of providing flexibility to the electricity grid.

Subsequently, the formulated capacity expansion model is employed for the evaluation of optimal capacity, electricity generation, and fuel composition in the context of Bangladesh, considering diverse emission reduction scenarios as potential strategies to align with the objectives set forth in the Paris Agreement. Additionally, the model investigates the influence of cross-border power exchange, extensive integration of intermittent renewable energy sources, and increased utilization of domestic coal resources on the selection of technological options. Various policy scenarios are developed to assess these impacts. Furthermore, a sensitivity analysis encompasses the examination of the implications of reduced prices for imported liquefied natural gas (LNG).

2. Methods

This study elaborates the author's capacity expansion model explained in Ref. [11]. It employs linear programming techniques to solve a large number of linear constraints and minimize total costs. The model incorporates two distinct fuel supply modes, namely native production and imports, for thermal power plants, and their respective proportions are calculated internally by the model. This examination primarily concentrates on the supply aspect, specifically the optimal capacities of the power plants under consideration, along with the battery system. Additionally, it determines the quantity of curtailed power generation originating from intermittent renewable energy sources. The assessment of simulation outcomes involves the comparison of various outputs, encompassing the optimal technology configuration, cost implications, emission levels, and electricity pricing, all based on externally provided hourly electricity demand data.

The model involves in the optimization of power generation allocations for a range of thermal plants, including those utilizing coal, oil, gas, nuclear and biomass, as well as two categories of intermittent renewable energy sources (wind and solar PV), one type of hydropower, and a Sodium-Sulfur (NaS) battery. This optimization process spans the study's timeframe, which extends up to the year 2050, with the base year set as 2015. The model conducts optimization for each hour at seven distinct time points (2020, 2025, ..., 2050). Notably, the optimal expansion capacities for the different technologies considered are calculated internally through the optimization process. For reference, Table 1 provides a comprehensive list of the endogenous variables and indices employed throughout this paper.

A detailed description of objective function and its mathematical formulation is taken from Ref.[11]. The objective function is illustrated by equation (1) taking 5% discount rate () and the annual costs for each considered technologies are expressed in the form of variable and fixed cost as expressed in equation (2). Equations (3), (4), and (5) depict the fixed costs related to power plants, batteries, and transmission network respectively. The annual variable costs include imported fuel, domestic fuel, and imported electricity cost as illustrated in equations (6-8).

Table 1: Endogenous variables

Variables	Unit	Definitions
AC_{y}	[Million USD]	Annual costs
$A_{y,d,p}$	[GW]	Available capacity for power generation
$C_{y,p}$	[GW]	Power plant capacity
$C_{y,s}$	[GW]	Storage technology capacity (power)
$C_{y,l}$	[GW]	Transmission line capacity
$CP_{y,p}$	[Million USD]	Fixed cost of power plants
$CS_{y,s}$	[Million USD]	Fixed cost of storage technologies
$CT_{y,l}$	[Million USD]	Fixed cost of transmission lines
$CF_{y,p,q}$	[Million USD]	Variable cost of fuel for thermal power plants
$CI_{y,l}$	[Million USD]	Variable cost of imported electricity
$EC_{y,s}$	[GWh]	Installed capacity (energy) of storage technology
$FI_{y,p}$	[Mtoe]	Imported fuel
$Fp_{y,g,p}$	[Mtoe]	Fuel produced within the country
J	[Million USD]	Total costs
$MK_{y,m,p}$	[GW]	Power plant capacity under maintenance schedule
$MP_{y,d,p}$	[GW]	Maximum power output of power plant
$NC_{y,p}$	[GW]	Power plant newly constructed capacity
$NC_{y,s}$	[GW]	Storage technology newly installed capacity (power)
$NC_{y,l}$	[GW]	Transmission line newly constructed capacity
$NEC_{y,s}$	[GWh]	Storage technology newly installed capacity (energy)
$SE_{y,t,s}$	[GWh]	Stored energy in storage technology
$X_{y,t,p}$	[GW]	Electricity generated by power plant
$Xs_{y,t,p}$	[GW]	Power suppressed within the power plant
$Xc_{y,t,s}$	[GW]	Power charged in storage technology
$Xd_{y,t,s}$	[GW]	Power discharged by storage technology
$Xi_{y,t,l}$	[GW]	Power transmitted towards reference node

where the indices are defined as follows

$c \in$	1: residential, 2: industrial, 3: service, 4: transport i.e. sectors [C = 4]
$d \in$	1, 2, 3,. . . , D, i.e. number of days in a year [D = 365]
$g \in$	1, 2, . . . , G, i.e. fuel cost grades [G = 8]
$l \in$	1, . . . , L, i.e. cross-border transmission networks [L = 4]
$m \in$	1, 2, . . . , M i.e. maintenance plans [M = 4]
$p \in$	1: nuclear, 2: coal, 3: gas, 4: biomass, 5: oil, 6: solar PV, 7: wind, 8: hydro i.e. power plants [P =8]
$q \in$	1: domestic production, 2: imported, i.e. mode of fuel supply [Q = 2]
$s \in$	1: NaS battery i.e. storage technologies [S =1]
$t \in$	1, 2, . . . , T, i.e. time slices in a year [T = 8760]
$y \in$	0, 1, 2, 3, . . . , Y, i.e. calculation points [Y = 7]
$year_y c$	year_0: 2015, year_1: 2020,.., year_y: 2050, time step between two calculation points [Z = 5]

$$J = \sum_{y=0}^{Y} \left(\sum_{z=1}^{Z} \frac{1}{Z} \left(\frac{z}{(1+\gamma)^{Zy+z}} + \frac{Z-z}{(1+\gamma)^{Z(y+1)+z}} \right) \cdot \mathrm{AC}_y \right) \tag{1}$$

$$\mathrm{AC}_y = \sum_{p=1}^{P} CP_{y,p} + \sum_{s=1}^{S} CS_{y,s} + \sum_{l=1}^{L} CT_{y,l} + \sum_{q=1}^{Q} \sum_{p=1}^{P} CF_{y,p,q} + \sum_{l=1}^{L} CI_{y,l} \tag{2}$$

$$CP_{y,p} = crf_p \cdot ucc_{y,p} \cdot (C_{y,p} - rc_{y,p}) \tag{3}$$

$$CS_{y,s} = crf_s \cdot \left(ucc_{y,s} \cdot (C_{y,s} - rc_{y,s}) + uecc_{y,s} \cdot (EC_{y,s} - rec_{y,s}\right) \quad (4)$$

$$CT_{y,l} = crf_l \cdot ucc_{y,l} \cdot l_l \cdot (C_{y,l} - ic_l) \quad (5)$$

$$CF_{y,p,1} = Fi_{y,p} \cdot (ifc_p \cdot ir_{y,p} + lp_p \cdot fr_p) \cdot (1 + ct_p) \cdot (1 + gst_p) \quad (6)$$

$$CF_{y,p,2} = \left(\sum_{g=1}^{G} \left(Fp_{y,g,p} \cdot (pc_{g,p} + lm_p \cdot fr_p)\right) \right) \cdot (1 + gst_p) \quad (7)$$

$$CI_{y,l} = iep_{y,l} \cdot \sum_{t=1}^{T} Xi_{y,t,l} \quad (8)$$

Where crf_p, crf_s, and crf_l are capital recovery factors; $ucc_{y,p}$ [\$/kW], $ucc_{y,s}$ [\$/kW], $uecc_{y,s}$ [\$/kWh], and $upc_{y,l}$ [\$/kW/km] are unit fixed costs; $rc_{y,p}$ [GW], $rc_{y,s}$ [GW], and $rec_{y,s}$ [GWh] are residual capacities from 2015 of the p^{th} power plant and s^{th} storage system; ic_l [GW]is the installed capacity at the base year, and l_l [km] is the length of the l^{th} transmission line, $pc_{g,p}$ [\$/toe] is the fuel production cost grade g,ifc_p [\$/toe]is the imported fuel price, fr_p [\$/toe.km] is the transportation rate, $ir_{y,p}$ [%]is the imported fuel price variation rate in year y for the gst_p [%] and ct_p [%] are service and custom charge rates, lmp (km) is the span between the typical p^{th} power plant and mines, and iep_y, l [\$/kWh] is the per unit cost of imported electricity through the l^{th} transmission line.

Equation (9) is expressed to maintain balance between demand and supply at every time step within the model.

$$\text{load}_{y,t} = \sum_{p=1}^{P} X_{y,t,p} + \sum_{s=1}^{S} (X_{d_{y,t,s}} - X_{c_{y,t,s}}) + \sum_{l=1}^{L} X_{i_{y,t,l}} \quad (9)$$

where, $load_y, t$ [GW] is exogenously provided electricity demand for each time step.

The anticipated profile of the future load curve is determined by taking into account the annual power demand, the proportion of electricity utilizing sectors within the total demand, and their respective daily and hourly coefficients from the base year. This estimation is represented by equation (10). To calculate the annual electricity demand, equation (11) is employed, utilizing a logarithmic regression model, while incorporating pertinent assumptions regarding the required input data for population and GDP projections in the future.

$$\text{load}_{y,t} = \frac{\text{aed}_y}{T} \sum_{c=1}^{C} \text{ss}_{y,c} \cdot \text{dc}_{d,c} \cdot \text{hc}_{t,c} \quad (10)$$

$$\ln\left(\text{aed}_y\right) = a' + b' \cdot \ln\left(\text{gdp}_y\right) + c' \cdot \ln\left(\text{pop}_y\right) \quad (11)$$

where aed_y [GWh] is annual electricity demand, ss_y, c [%] is the percentage share of electricity consuming sectors,dc_d, c and hc_t, c is daily and hourly coefficients, respectively, gdp_y is the gross domestic product in year y, pop_y is the population in year y, and a', b' and c' are constant term, GDP and population elasticities, respectively.

Equation (12) demonstrates that the manufacture of various cost categories of fuel utilized in thermal power plants is restricted by their production capacity limits. Equation (13) regulates the reserve limit of exhaustible fuels throughout the study period. The imported and domestic fuel shares for electricity generation are determined by equation (14).

$$\sum_{g=1}^{G} Fp_{y,g,p} \leq pmax_{y,p} \quad \text{for } p = 1, \dots, 5 \quad (12)$$

$$Z \cdot \sum_{y=0}^{Y} Fp_{y,g,p} < res_{g,p} \quad \text{for } p = 1, \dots, 5 \quad (13)$$

$$\sum_{t=1}^{T} X_{y,t,p} \leq (Fi_{y,p} + \sum_{g=1}^{G} Fp_{y,g,p}) \cdot hc_{y,p} \quad \text{for } p = 1, \dots, 5 \quad (14)$$

where $pmax_y, p$ [Mtoe] is the maximum production capacity of fuel used in pth power plant in year y, res_g, p [Mtoe] is exhaustible reserves of fuel of cost grade g for $p^t h$ power plant.

The cross-border electricity supply is regulated by the availability factor and the transmission lines' capacity as depicted in equation (15).

$$Xi_{y,t,l} \leq af_{d,l} \cdot C_{y,l} \quad (15)$$

where af_d, l is defined as an availability factor of $l^t h$ power transmission lines.

Equation (16) is formulated to maintain the capacity reserve constraints.

$$\sum_{p=1}^{5} A_{y,d,p} + \sum_{p=8}^{8} cf_{d,p} \cdot C_{y,p} + \sum_{s=1}^{S} cfp_s \cdot C_{y,s} \geq (1+\delta) \cdot \text{load}_{y,t} \tag{16}$$

where δ [=10%] is the capacity reserve margin.

Equation (17) is developed to implement emission restriction in each representative year.

$$\sum_{p=1}^{P} \left(\frac{44 \cdot cc_p}{12 \cdot hc_{y,p}} \cdot \sum_{t=1}^{T} X_{y,t,p} \right) \leq emax_y \tag{17}$$

where cc_p [kg-C/toe] is the carbon content in the fuel, and hc_p [kWh/toe] is the thermal conversion of 1 toe of fuel consumed in $p^t h$ power plant, $emax_y$ [Mt-CO_2e] is CO_2 emission limit.

The model regulates thermal power plants, hydropower, and renewable power plants, storage technologies through operational and capacity addition constraints as explained in the Appendix A section of this paper.

3. Model input

3.1. Development of electricity demand

Over the past decade, Bangladesh experienced consistent economic growth at a rate of 7.3%, alongside an annual electricity demand increase of approximately 7%, coinciding with an expansion of electricity access to 90% of the population. As of 2018, per capita electricity consumption reached 464 kWh. The pattern of electricity demand in Bangladesh exhibits an ascending trajectory, marked by seasonal fluctuations. Broadly, Bangladesh witnesses a hot and humid climate till June starting from March, characterized by high temperatures ranging from 30°C to 40°C. Conversely, January represents the coolest month, with temperatures around 10°C. During the winter season, Ramadan festivals, and weekends, there is typically a reduction in electricity demand. The base year electricity demand for this study was taken from the daily generation reports [32] as shown in Figure 1

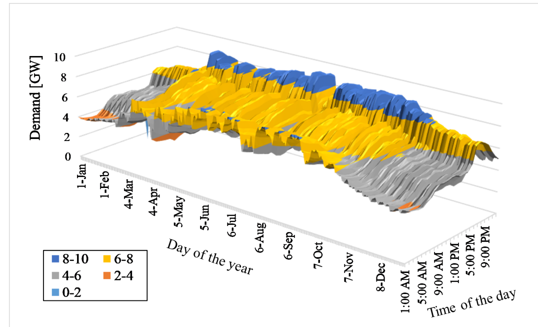

Figure 1: Electricity consumption throughout the year, on an hourly basis, in Bangladesh (2015).

Electricity demand typically reaches its peak during the late evening or nighttime, but it is also influenced significantly by weather conditions. In the wet season, the load factor tends to increase during late-night hours due to increased electricity usage for water pumping purposes, primarily related to irrigation. Notably, the residential sector accounts for approximately 52% of the total electricity demand, while the industrial sector comprises around 32%, a proportion that is steadily rising due to ongoing industrialization in the country. Additionally, as people's lifestyles evolve, it is expected that the share of the service sector will grow in the future. Historical data analysis reveals a strong correlation between electricity consumption in Bangladesh, GDP and population. This study forecasts yearly electricity demand until 2050 using a log-regression model based on population and GDP, as described in equations (10) and (11). Given that Bangladesh has experienced an average GDP growth rate of over 7% annually in the past five years, it is assumed that the maximum GDP growth rate will gradually decline to 9.5%, 8.0%, and 7.0%, with further reductions to 7.0%, 6.0%, and 5.0% by 2050 in scenarios representing high, medium, and low GDP growth rates, respectively.

Hourly electricity demand for each selected representative year was forecasted by employing the estimated annual electricity consumption, along with the hourly and daily coefficients obtained from the base year's data and the respective proportions of power-consuming sectors, as delineated in equation (11). The hourly coefficient is calculated as the demand at a specific time divided by the average demand for that particular day, while the daily coefficient is calculated as the demand on a given day divided by the average demand for that entire year. The representative illustration of load coefficients for four distinct power-consuming sectors on a specific day is presented in Figure 2, while Figure 3 provides a typical example showcasing the evolving load curves for each of the selected representative years.

3.2. Resource availability

The estimations of gas and coal reserves in Bangladesh are based on available information found in Refs.

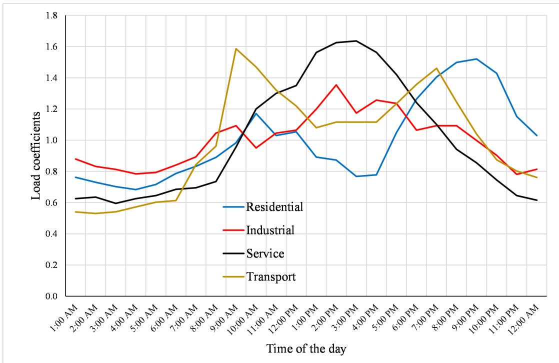

Figure 2: Representation of the load profile for sectors consuming electricity in Bangladesh.

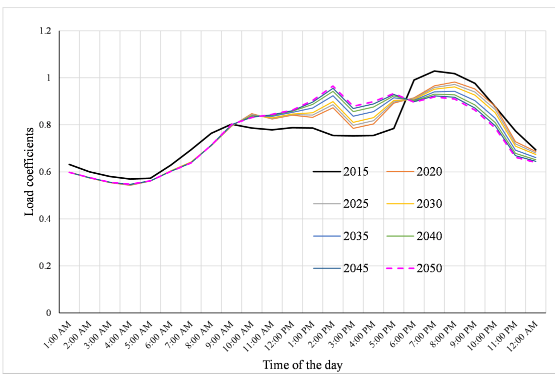

Figure 3: Predicted standard load profiles for selected years.

[33]and [34]. It is assumed in this model that the manufacture capacity for gas and coal will rise at past growth rates. However, it's worth noting that there are several challenges hindering the substantial utilization of domestic coal reserves [35] [36], including issues related to land acquisition, water management, resettlement, environmental impact, and sustainability. Based on historical usage patterns, this model assumes that 60% of the total gas reserves are allocated for the electricity sector. Regarding renewable energy sources, the model considers the existing Kaptai hydropower plant (230 MW) and estimates the maximum potential for biomass power generation at approximately 275 MW, primarily from sources like rice husk and rice straw[37][38]. Furthermore, the maximum capacities for solar photovoltaic (PV) and wind energy in Bangladesh are set at 20 GW and 1 GW, respectively, based on estimations provided in a report [4]. These estimates take into account the availability of wasteland within twenty km of transmission network locations. The computational methods employed to determine the hourly capacity factors for solar PV and wind are detailed in Refs.[39] and [40] and are extracted from Ref. [41]. Since Bangladesh lacks significant potential for pumped storage, the model exclusively considers Sodium-Sulfur (NaS) batteries as options for power storage.

3.3. Assumptions on cost and technical parameters

In this model, it is assumed that there are four interconnection lines linking Bangladesh with its neighboring countries, specifically Bhutan, Nepal, India's northeastern grid, and India's eastern grid. Currently, Bangladesh maintains connections with India's eastern grid and northeastern grid with capacities of approximately 1000 MW and 160 MW, respectively [42]. The capacity expansion for these proposed connections with nearby countries, as depicted in Figure 4, is internally calculated within the model. The cost associated with each cross-border transmission line is calculated by considering a unit construction cost of 1.5 \$/km per kW, accounting for the appropriate type of connection and the distance, and it also incorporates the additional cost related to the inverter[43].

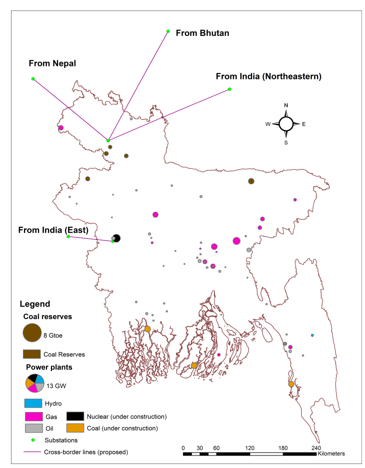

Figure 4: Illustration of Power Plant Distribution,Cross-Border Transmission Lines and Coal Reserves as Considered in the Model

In Bangladesh, electricity generation relies on a mix of reciprocating engines, gas turbines, steam turbines, and combined-cycle systems powered by coal, oil and gas-based thermal power plants. The country is committed to enhancing the efficiency of these power plants and adopting advanced technologies to optimize fuel utilization while minimizing emissions. As a result, this model incorporates an incremental enhancement in the efficiency of coal-based power plants and the development of combined-cycle gas-based power plants for forthcoming schemes. The initial installed capacity of thermal power plants, used as a reference point, is derived from the data in Ref.[1]. Detailed information

Table 2: Technical input data for considered technologies

Parameter	Nuclear	Coal	Gas	Biomass	Oil	Hydro	PV	Wind	Battery
Lifetime [year]	50	40	35	30	30	60	25	25	15
Efficiency [%]	33	34 38	44 54	20	39				
Own consumption rate [%]	0.04	0.062	0.02	0.13	0.05				
Carbon content [kg-C/toe]	0.00	1075	576	7	800				
Carbon capture rate [%]	0	0	0	0					
Seasonal peak availability	0.81	0.79	0.88	0.74	0.86				
Annual average availability	0.76	0.73	0.81	0.67	0.76				
Share of daily start and stop	0	0	0.5	0	0.7				
Minimum output level	0.3	0.3	0.2	0.3	0.3				
Maximum increase rate of output [1/hour]	0.01	0.3	0.82	0.31	1				
Maximum decrease rate of output [1/hour]	0.01	0.58	0.75	0.58	1				
Annual availability factor [%]						40	17	22	-
kW capacity factor [%]									90
kWh capacity factor [%]									95
Self-discharge rate [1/hour]									0.001
Cycle efficiency [%]									90
C-rate									0.14
Maximum number of the life cycle [cycles]									4500

regarding unit construction costs, operational costs, and maintenance expenses is sourced from Ref.[18], while assumptions regarding the cumulative production cost curve for native fuel and the pricing of imported fuel are explained in Ref. [13]. The technical parameters defining the operational attributes of the technologies under consideration are provided in Table 2.

3.4. Scenario design

The simulation was conducted across three distinct scenarios of electricity demand growth, specifically categorized as the high growth rate (HGR), medium growth rate (MGR), and base growth rate (BGR) scenarios. These projections for power demand align with the approximations previously detailed in the previous section. To explore sustainable trajectories, an additional set of four scenarios, each incorporating emission regulations, has been formulated within each of the demand growth rate scenarios. The emission restrictions have been established as a percentage decrease in comparison to the emissions increment observed between successive representative years within the HGR, MGR, and BGR scenarios. The specified percentages considered are 20%, 40%, 60%, and 80%.

To further explore potential electricity supply options in response to increased electricity demand and stringent emission regulations, a total of nine cases have been formulated, as outlined in Table 3, specifically within the framework of the high growth rate (HGR) scenario. Across all these scenarios, an examination of the long-term power generation mix is conducted under conditions of 80% CO_2 regulation. The assessment encompasses an evaluation of the influence of electricity imports from nearby countries such as India, Bhutan and Nepal, with considerations given to three distinct import capacity limits set at 5 GW, 10 GW, and 15 GW. Similarly, the study also examines the effects of increased solar PV capacity on the generation mix, where the maximum estimated potential is relaxed. Additionally, the effect of increased domestic coal manufacture and the potential price decrease of imported LNG are analyzed as part of the sensitivity study.

4. Results and discussions

The model results were generated using IBM CPLEX optimization studio on a CentOS Server of 64 GB memory and Xeon L5640 at 2.27 GHz with 6 cores that can operate 12 threads concurrently. It took about 15 minutes to solve each model with an approximate size of about 1 million variables and 3.12 million constraints.

4.1. Capacity and generation mix

Given the rapidly expanding economic activities within Bangladesh, a significant surge in electricity demand is anticipated by the year 2050. In comparison to the base year's electricity demand of 55 TWh, the projections indicate an increase to 404TWh, 311 TWh, and 256 TWh by 2050 for the HGR, MGR, and BGR scenarios, respectively.

A notable transition from a predominance of gas to coal as the primary energy source is evident in the generation mix (Figure 5) across entire scenarios. This shift is primarily driven by the inadequate availability of cost-effective native gas beyond the year 2030, necessitating

Table 3: Cases under HGR scenarios

Criteria	Case									
	Units	I	II	III	IV	V	VI	VII	VIII	IX
CO_2 regulation	[%]	80	80	80	80	80	80	80	80	80
Power import maximum limit	[GW]		5	10	15			15	15	15
Restriction on solar PV deployment	[GW]	20	20	20	20	∞	20	∞	∞	∞
Domestic coal production	[Mtoe]						>5	>5	>5	>5
LNG import price reduction	[%]								10	20

a transition to coal as an alternative fuel source. Subsequently, a consistent uptrend in coal usage is detected in all scenarios after 2030, while the gas share declines. Across all scenarios, gas-fired power plants fulfill the role of load-following operations, eliminating the imperative need for additional storage facilities. Furthermore, the contribution of solar photovoltaic (PV) remains relatively stable after 2030, while other energy sources such as nuclear, wind, and biomass appear to become comparatively more expensive in scenarios where there are no restrictions on CO_2emissions.

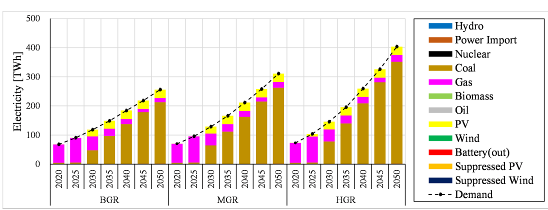

Figure 5: Trajectories of Optimal Generation Mix and the Electricity Demand in Each Scenario

In order to align with the projected demand, Figure 6 illustrates the transition of the optimal capacity composition across three different scenarios. By the year 2050, the installed capacity expands to 121 GW, 98 GW, and 81 GW, while the emission levels surge approximately 12-fold, 9-fold, and 7-fold in comparison to the base year levels for the HGR, MGR, and BGR scenarios, respectively. Notably, the integration of solar PV into the capacity mix commences merely after 2030, with its expansion constrained by the projected potential in all scenarios. Furthermore, existing oil-fired and a portion of gas-based power plants primarily assist as reserve capacity rather than being actively utilized for power generation.

Figure 7 presents the optimal generation mix within various CO_2 regulation scenarios for the year 2050. The outcomes indicate that nuclear energy emerges as the most dependable choice for Bangladesh in its pursuit of sustainable objectives, primarily to diminish the reliance on coal. This shift is attributed to the constraints on the

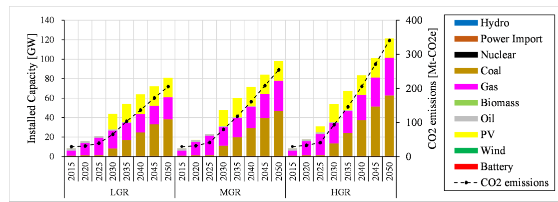

Figure 6: Transition of the CO_2 emissions and optimal capacity mix in each scenario

potential of cleaner sources such as solar photovoltaic PV and wind, coupled with the significant uncertainties and elevated costs associated with imported LNG. Notably, the proportion of nuclear energy increases in a proportional way with the intensification of emission regulations across considered three scenarios.

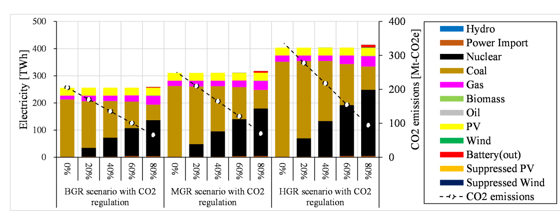

Figure 7: 2050's Optimal generation mix in CO_2 regulation scenarios

Figure 8 illustrates the capacity and total costs prerequisites essential to fulfill the projected demand in diverse CO_2 regulation scenarios by the year 2050. In the scenario with an 80% CO_2 regulation, the total cost escalates by nearly 7% in comparison to the scenario with no emission restrictions. The requisite nuclear capacity surges to 36 GW, 26 GW, and 20 GW across the three growth rate scenarios within the context of 80% CO_2 regulation. Consequently, the requirement for NaS battery capacity becomes apparent to facilitate load-following operations. This is due to the model's inherent constraint on the load-following operation of nuclear power plants.

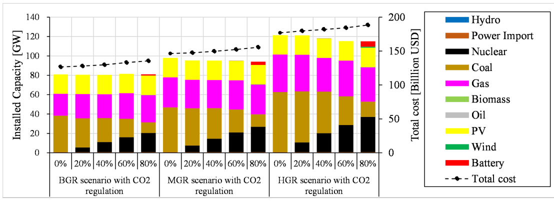

Figure 8: Optimal capacity mix and Total costs in CO_2 regulation scenarios in 2050

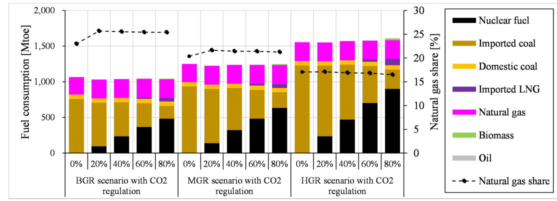

Figure 10: Fuel mix and share of natural gas in CO_2 regulation scenarios in 2050

4.2. Fuel mix

Figure 9 provides insights into the gradual depletion of indigenous natural gas over time and its role in fuel contribution within three distinct growth rate scenarios. Despite being cost-effective, the indigenous gas reserve diminishes notably faster after 2030 in all scenarios due to its finite availability. By the year 2050, the energy sector of Bangladesh necessitates approximately 88 Mtoe, 66 Mtoe, and 53 Mtoe of fuel in the HGR, MGR, and BGR scenarios, respectively. The bulk of this demand is met through imported coal, with a minimal portion from domestic coal sources. Meanwhile, electricity generation from biomass and furnace oil remains a costly alternative across all scenarios.

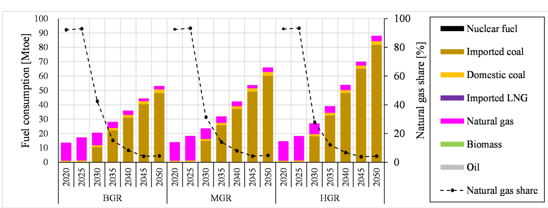

Figure 9: Fuel mix and contribution of natural gas for 2020-50 in each scenario

However, with the introduction of CO_2 regulations in the scenarios characterized by different growth rates, coal and gas proportions are predominantly displaced by nuclear fuel. This shift also results in a reduction in the rate at which indigenous gas reserves are depleted, as depicted in Figure 10. Furthermore, the demand for imported gas rises in direct correlation with increased emission reduction targets.

4.3. Influence of gas price and policies

Figure 11 portrays the outcomes of the optimization process pertaining to the generation mix and electricity pricing in the year 2050 across nine distinct scenarios, as explained in the scenario section. The findings suggest that importing electricity from nearby countries emerges as a financially advantageous approach for attaining sustainable objectives. This, in turn, results in reduced reliance on nuclear, coal, and gas sources within the generation mix. Likewise, an extensive deployment of solar PV technology and the integration of batteries for energy storage can diminish the dependence on nuclear power. However, this entails a reevaluation of the current government assessments regarding the potential of solar PV. Increased domestic coal production, on the other hand, has a limited impact on overall cost reduction. Additionally, reductions in gas prices contribute to a decrease in the share of coal and nuclear in the generation mix.

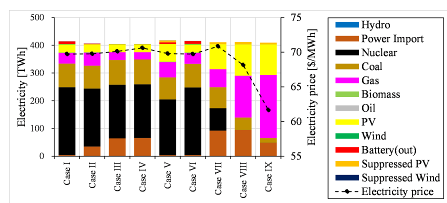

Figure 11: Electricity price and optimal generation mix in nine different cases in 2050.

Figure 12 provides an overview of the optimization outcomes pertaining to the total cost and capacity mix in the year 2050 across nine distinct scenarios. In instances characterized by reductions in gas prices, the solar PV capacity experiences a notable increase, reaching up to 85 GW. Moreover, scenarios marked by a substantial presence of nuclear power plants witness an expansion in battery capacity requirements, while cases with a significant share of gas-fired power plants exhibit reduced demand for batteries, due to their inherent load-following capabilities. The overall total cost demonstrates a decreasing trend with an increase in coal production, power imports, and a decline in the price of imported gas.

Figure 13 illustrates how various scenarios influence the cumulative fuel consumption and the influence of native gas within the overall share. While the total utilization of native natural gas remains relatively consistent across all scenarios, its proportion fluctuates from one case to another. Electricity imports from nearby countries, increased utilization of solar PV generation, and reduced costs associated with LNG directly influence the dependency on nuclear fuel.

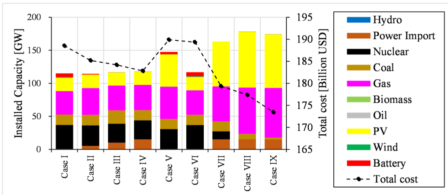

Figure 12: Optimal capacity mix and total costs in nine different cases in 2050.

4.4. Influences of variation in load curve shape

While the influence of alterations in the load curve shape is observed to have a relatively modest impact on overall costs compared to capacity mix, the simulation outcomes emphasize its significance across various scenarios. Figure 14 illustrates the fluctuations in total costs and the optimal capacity mix for the year 2050 when compared to unaltered scenarios, highlighting the implications of variations in the load curve shape. In most instances, the consideration of load curve changes leads to an increase in total costs, accompanied by notable variations in the capacities of nucleasr, solar PV, and gas-fired power plants. In instances where load curve shapes are altered, daytime power demand rises, necessitating an expanded role for gas-fired and solar PV power plants in load-following operations.

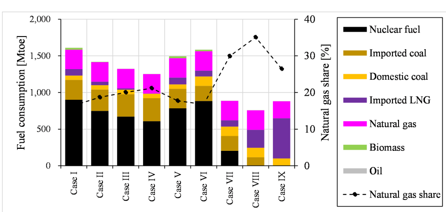

Figure 13: Cumulative Fuel Consumption from 2015 to 2050 and Proportion of Indigenous Natural Gas within the HGR Scenario in Nine Distinct Cases

This model is intentionally designed to allow easy adjustment of temporal resolution. Figure 15 illustrates the variations in total costs and the optimal capacity mix when transitioning from a 1-hour model to 2-hour, 3-hour, 4-hour, and 6-hour time steps. As the temporal resolution decreases, the proportion of solar PV capacity within the capacity mix expands, concurrently decreasing the contributions of nuclear and gas sources. This phenomenon arises because the intermittency of solar PV diminishes as the model's temporal resolution is lowered, consequently leading to a natural reduction in the overall power system costs. While the computational demands associated with hourly time steps are considerable, they provide a more precise understanding of the technical capabilities of the technologies under consideration, including intermittent renewables and storage technologies.

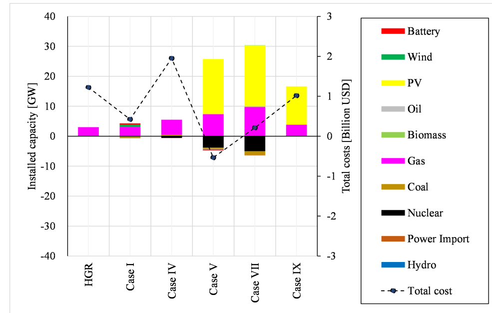

Figure 14: Variations in optimal capacity mix and total costs due to load curve shape adjustments in six distinct cases in 2050.

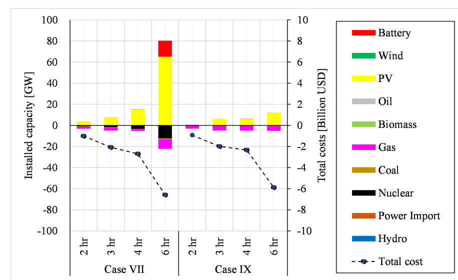

Figure 15: Variations in optimal capacity mix and total costs resulting from temporal resolution adjustments in two distinct cases in 2050

Figure 16 and Figure 17 illustrate alterations in the optimal power dispatch profile and the contributions of various power generators in 2050 when the load curve shape undergoes modifications in six specific scenarios. The consideration of load curve shape adjustments results in a shift in peak demand to daytime, as opposed to the evening peak observed in scenarios where the base year load curve shape is retained. This major difference significantly influences the selection of optimal solar PV capacities and is evident in the optimal power dispatch profiles. Nuclear power and coal plants function as baseload generators, while solar PV exclusively operates during daytime hours. Given the limited flexibility of nuclear power plants, batteries are vital for load balance when nuclear generation exceeds demand. Gas-based power plants primarily work as peaking plants across most scenarios. In scenarios where gas prices are reduced, the power generation from gas increases, and it operates with greater flexibility. The model demonstrates that flexible imported power supply serves as the optimal power dispatch strategy for

Bangladesh. However, it's important to note that cross-border power trading is facilitated by mutual agreements between countries involved.

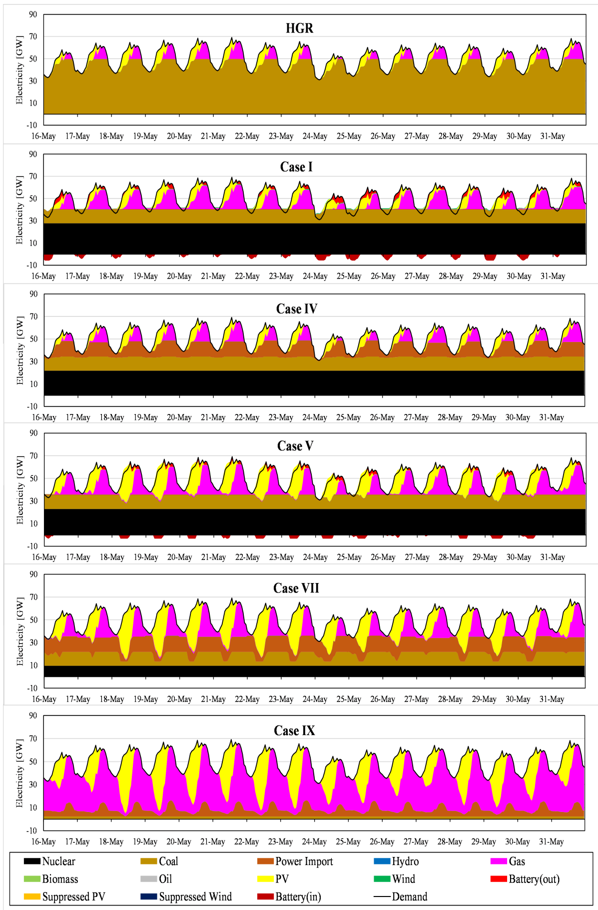

Figure 16: Simulation outcomes for the ideal power dispatch strategy spanning from 16th May to 31st May in 2050, encompassing six distinct scenarios featuring variations in load curve shapes.

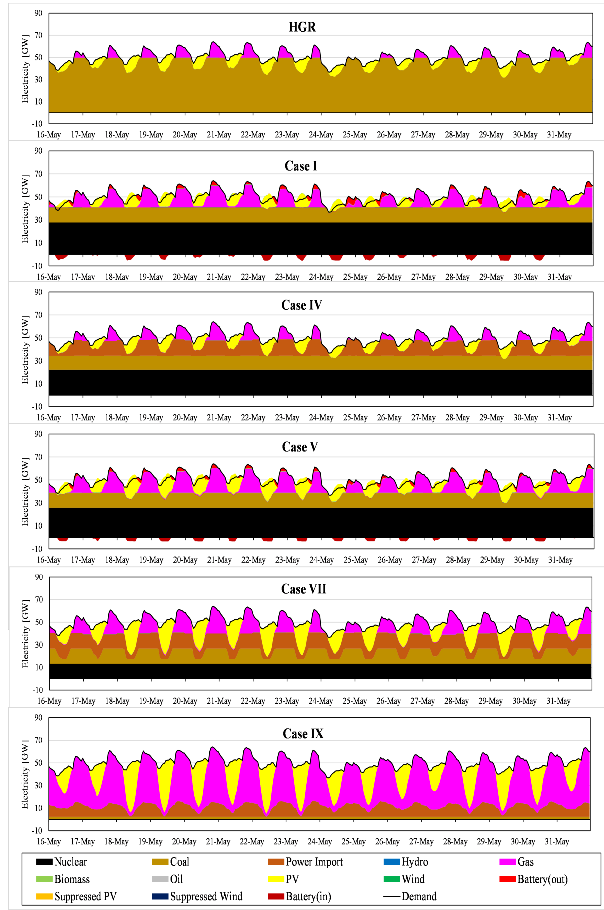

Figure 17: Simulation findings depicting the optimal power dispatch strategies during the period from May 16th to May 31st in 2050, encompassing six unique scenarios in which load curve shapes remain unaltered.

5. Conclusion

A capacity expansion model has been developed to comprehensively incorporate the operational attributes of diverse power generation and storage technologies, while also optimizing the utilization of native energy resources. This model has been applied to assess the most effective expansion strategy for Bangladesh's electricity sector, serving as a case study, across emission reduction scenarios and various demand growth rate, aligning with the objectives of the Paris Agreement. Furthermore, this study examines the repercussions of cross-border electricity exchange, extensive deployment of intermittent renewable energy sources, augmented indigenous coal production, and variations in the price of imported LNG through an array of policy scenarios. The simulation outcomes in a high-growth rate scenario, without emission constraints, project a capacity requirement of approximately 121 GW to satisfy the projected annual demand of 404 TWh in 2050. In this scenario, emissions surge twelvefold relative to 2015 levels. The net present value of total costs across the study period stands at roughly 126 billion USD in the base growth rate scenario, experiencing a 40% and 16% increase in high and medium growth rate scenarios, respectively. In the pursuit of decarbonizing the power sector to align with Paris Agreement targets, nuclear energy emerges as the most dependable option, considering the limited potential of cleaner alternatives such as solar PV and wind in the context of Bangladesh. By curbing 80% of CO_2 emissions, the total cost increment remains at 7%. The domestic natural gas resource, while cost-effective, faces depletion beyond 2030 due to finite reserves. Consequently, the demand for imported gas escalates with

heightened carbon regulation, though the proportion of gas-based power generation diminishes from current levels due to the relatively higher cost and uncertain nature of imported LNG pricing. An economically advantageous alternative appears to be importing electricity from nearby nations like India, Nepal and Bhutan. To further mitigate dependence on nuclear power, substantial deployment of solar PV alongside integrated battery storage presents a viable strategy.
Taking into account variations in load curve shape during the analysis augments total costs and elevates the shares of gas and solar PV in the capacity mix. This study endeavors to offer valuable insights for the formulation of energy policies in Bangladesh, emphasizing the significance of cross-border electricity trade with neighboring countries.

Acknowledgements

This work is supported by the University Grants Commission, Nepal (Award Number CRG-78-79-Engg-02).

Appendix A

The performance of thermal power plants is governed by constraints related to load-following, maintenance schedules, and minimum output levels as illustrated in equation (A.1-A.8). Refer to [44] for detailed descriptions.

$$X_{y,t,p} \leq A_{y,d,p} \quad (p = 1, \ldots, 5) \tag{A.1}$$

$$A_{y,d,p} + \sum_{m=1}^{4} (u_{r,d,m} \cdot MK_{y,m,p}) = C_{y,p} \quad (p = 1, \ldots, 5) \tag{A.2}$$

$$\frac{1}{D} \sum_{m=1}^{M} \sum_{d=1}^{D} (u_{r,d,m} \cdot MK_{y,m,p}) = (1 - aa_p) \cdot C_{y,p} \quad (p = 1, \ldots, 5) \tag{A.3}$$

$$\sum_{m=1}^{M} (u_{r,d,m} \cdot MK_{y,m,p}) \geq (1 - sa_p) \cdot C_{y,p} \quad (p = 1, \ldots, 5) \tag{A.4}$$

$$X_{y,t,p} \geq \mathrm{mol}_p \cdot (MP_{y,d,p} - dss_p \cdot A_{y,d,p}) \quad (p = 1, \ldots, 5) \tag{A.5}$$

$$MP_{y,d,p} \geq X_{y,t,p} \quad (p = 1, \ldots, 5) \tag{A.6}$$

$$MP_{y,d,p} \geq P_{y,d+1,p} \quad (p = 1, \ldots, 5) \tag{A.7}$$

$$X_{y,t-1,p} - \mathrm{decrease}_p \cdot A_{y,d,p} \leq X_{y,t,p} \leq X_{y,t-1,p} + \mathrm{increase}_p \cdot A_{y,d,p} \quad (p = 1, \ldots, 5) \tag{A.8}$$

where, $ur_{d,m}$ is shutdown occurrence rates under m^{th} maintenance schedule in day d, sa_p is seasonal peak availability and aa_i is yearly average availability of p^{th} thermal power plant plants, dss_p is daily share of start and stop, and mol_p is minimum operation level of p^{th} thermal power plant plants,$increase_p$ and $decrease_p$ is maximum increase and maximum decrease rate of the power output of p^{th} thermal power plant plants.
The electricity output from fluctuating renewables and hydropower is illustrated by equations (A.9) and (A.10) and explained in Ref.[10].

$$X_{y,t,p} + Xs_{y,t,p} = af_{t,p} \cdot C_{y,p} \quad (p = 6, 7) \tag{A.9}$$

$$X_{y,t,p} = af_{d,p} \cdot C_{y,p} \quad (p = 8) \tag{A.10}$$

where $af_{t,p}$ is the availability factor of intermittent renewables at each time step, $af_{d,p}$ is the daily availability factor of hydropower.
The operational characteristics of storage technologies are illustrated by equations (A.11-A.15) and are explained in ref.[45].

$$Xd_{y,t,s} + Xc_{y,t,s} \leq cfp_s \cdot C_{y,s} \tag{A.11}$$

$$S_{y,t,s} = S_{y,t-1,s} \cdot (1 - \mathrm{sdr}_s) + \left(\sqrt{\eta_s} \cdot Xc_{y,t-1,s} - \frac{1}{\sqrt{\eta_s}} \cdot Xd_{y,t-1,s} \right. \tag{A.12}$$

$$S_{y,t,s} \leq cfe_s \cdot EC_{y,s} \tag{A.13}$$

$$C_{y,s} \leq crate_s \cdot EC_{y,s} \quad (s = 1) \tag{A.14}$$

$$\sum_{t=1}^{T} Xc_{y,t,s} \leq \frac{cfe_s \cdot cycle_s}{lifetime_s} \cdot EC_{y,s} \quad (s=1) \quad \text{(A.15)}$$

where cfp_s is the capacity factor (power), sdr_s [1/hour] is self-discharge rate, η_s [%] is cycle efficiency, cfe_s is the capacity factor (energy), crates [1/hour] is C-rate, $cycle_s$ is the service life cycle, $lifetime_s$ [years] is the lifetime of s^{th} storage technology, respectively.
The optimal expansion of future capacities of each considered technology is determined through equations (A.16-A.21) and explained in ref.[10].

$$C_{y,p} = rc_{y,p} + \sum_{x=0}^{y} NC_{x,p} \cdot \mathrm{rem}_p(y,x) \qquad \text{(A.16)}$$

$$C_{y,s} = rc_{y,s} + \sum_{x=0}^{y} NC_{x,s} \cdot \mathrm{rem}_s(y,x) \qquad \text{(A.17)}$$

$$EC_{y,s} = rec_{y,s} + \sum_{x=0}^{y} NEC_{x,s} \cdot \mathrm{rem}_s(y,x) \quad \text{(A.18)}$$

$$c_{\min y,p} \leq C_{y,p} \leq c_{\max y,p} \qquad \text{(A.19)}$$

$$c_{\min y,s} \leq C_{y,s} \leq c_{\max y,s} \qquad \text{(A.20)}$$

$$\mathrm{ecmin}_{y,s} \leq EC_{y,s} \leq \mathrm{ecmax}_{y,s} \qquad \text{(A.21)}$$

where coefficient $rem_p(y,y')$ is defined as a lifetime matrix of p^{th} power plant, $cmin_{y,p}$ [GW] and $cmax_{y,p}$ [GW] are the minimum and maximum limit of p^{th} plant in year y, coefficient $rem_s(y,y')$ is defined as a lifetime matrix of s^{th} storage technology, $cmin_{y,s}$ [GW] and $cmax_{y,p}$ [GW] are minimum and maximum limit of power capacity and $ecmin_{y,s}$ [GWh] and $ecmax_{y,p}$ [GWh] are the minimum and maximum limit of energy capacity s^{th}storage technology in year y.

References

[1] Bangladesh Power Development Board (BPDB). Annual report 2017-18[Z]. Dhaka, Bangladesh, 2018.
[2] Bank T W. Lighting the way achievements, opportunities, and challenges in bangladesh's power sector[M]. Dhaka, Bangladesh, 2018.
[3] (JICA) J I C A. People's republic of bangladesh power & energy sector master plan (psmp2016)[M]. 2016.
[4] Authority S R E D. Scaling up renewable energy in low income countries (srep) investment plan for bangladesh[M]. Dhaka, Bangladesh, 2015.
[5] Karim R, et al. Nuclear energy development in bangladesh: A study of opportunities and challenges[J/OL]. Energies, 2018, 11(7): 1-15. DOI: 10.3390/en11071672.
[6] Hossain M F, Hossain S, Uddin M J. Renewable energy: Prospects and trends in bangladesh[J/OL]. Renewable and Sustainable Energy Reviews, 2017, 70(November 2016): 44-49. DOI: 10.1016/j.rser.2016.11.197.
[7] Bhattacharyya S C, Timilsina G R. A review of energy system models[J/OL]. International Journal of Energy Sector Management, 2010, 4(4): 494-518. DOI: 10.1108/17506221011092742.
[8] Ringkjøb H K, Haugan P M, Solbrekke I M. A review of modelling tools for energy and electricity systems with large shares of variable renewables[J/OL]. Renewable and Sustainable Energy Reviews, 2018, 96(April 2017): 440-459. DOI: 10.1016/j.rser.2018.08.002.
[9] Wise M, Patel P, Khan Z, et al. Representing power sector detail and flexibility in a multi-sector model[J/OL]. Energy Strategy Reviews, 2019, 26: 100411. DOI: 10.1016/j.esr.2019.100411.
[10] Komiyama R, Fujii Y. Long-term scenario analysis of nuclear energy and variable renewables in japan's power generation mix considering flexible power resources[J/OL]. Energy Policy, 2015, 83: 169-184. DOI: 10.1016/j.enpol.2015.04.005.
[11] Gyanwali K, Komiyama R, Fujii Y. Representing hydropower in the dynamic power sector model and assessing clean energy deployment in the power generation mix of nepal[J/OL]. Energy, 2020, 202: 117795. DOI: 10.1016/j.energy.2020.117795.
[12] Das A, Halder A, Mazumder R, et al. Bangladesh power supply scenarios on renewables and electricity import[J/OL]. Energy, 2018, 155: 651-667. DOI: 10.1016/j.energy.2018.04.169.
[13] Gyanwali K, Komiyama R, Fujii Y. Power sector analysis of the bbin sub-region with a spatially disaggregated dynamic power generation mix model[J/OL]. IEEJ Transactions on Electrical and Electronic Engineering, 2020: tee.23234. DOI: 10.1002/tee.23234.
[14] Baky M A H, Rahman M M, Islam A K M S. Development of renewable energy sector in bangladesh: Current status and future potentials[J/OL]. Renewable and Sustainable Energy Reviews, 2017, 73(April 2016): 1184-1197. DOI: 10.1016/j.rser.2017.02.047.
[15] Islam S, Khan M Z R. A review of energy sector of bangladesh[J/OL]. Energy Procedia, 2017, 110(December 2016): 611-618. DOI: 10.1016/j.egypro.2017.03.193.
[16] Halder P K, Paul N, Joardder M U H, et al. Energy scarcity and potential of renewable energy in bangladesh[J/OL]. Renewable and Sustainable Energy Reviews, 2015, 51: 1636-1649. DOI: 10.1016/j.rser.2015.07.069.
[17] Rahman M M, Kashem M A. Carbon emissions, energy consumption and industrial growth in bangladesh: Empirical evidence from ardl cointegration and granger causality analysis[J/OL]. Energy Policy, 2017, 110(March): 600-608. DOI: 10.1016/j.enpol.2017.09.006.
[18] Gyanwali K, Komiyama R, Fujii Y, et al. A review of energy sector in the bbin sub-region[J/OL]. International Journal of Sustainable Energy, 2020: 1-27. DOI: 10.1080/14786451.2020.1825436.
[19] Hainoun A, Aldin M S, Almoustafa S. Formulating an optimal long-term energy supply strategy for syria using message model[J/OL]. Energy Policy, 2010, 38(4): 1701-1714. DOI: 10.1016/j.enpol.2009.11.032.
[20] Hainoun A, Seif-Eldin M K, Almoustafa S. Analysis of the syrian long-term energy and electricity demand projection using the end-use methodology[J/OL]. Energy Policy, 2006, 34(14): 1958-1970. DOI: 10.1016/j.enpol.2004.12.024.
[21] Hainoun A. Construction of the hourly load curves and de-

tecting the annual peak load of future syrian electric power demand using bottom-up approach[J/OL]. International Journal of Electrical Power & Energy Systems, 2009, 31(1): 1-12. DOI: 10.1016/j.ijepes.2008.09.006.

[22] Kim C I, Yu I K, Song Y H. Prediction of system marginal price of electricity using wavelet transform analysis[J/OL]. Energy Conversion and Management, 2002, 43(14): 1839-1851. DOI: 10.1016/S0196-8904(01/00127-3.

[23] Weron R, Misiorek A. Forecasting spot electricity prices: A comparison of parametric and semiparametric time series models[J/OL]. International Journal of Forecasting, 2008, 24(4): 744-763. DOI: 10.1016/j.ijforecast.2008.08.004.

[24] Singhal D, Swarup K S. Electricity price forecasting using artificial neural networks[J/OL]. International Journal of Electrical Power & Energy Systems, 2011, 33(3): 550-555. DOI: 10.1016/j.ijepes.2010.12.009.

[25] Chang P C, Fan C Y, Lin J J. Monthly electricity demand forecasting based on a weighted evolving fuzzy neural network approach[J/OL]. International Journal of Electrical Power & Energy Systems, 2011, 33(1): 17-27. DOI: 10.1016/j.ijepes.2010.08.008.

[26] Suganthi L, Samuel A A. Energy models for demand forecasting - a review[J/OL]. Renewable and Sustainable Energy Reviews, 2012, 16(2): 1223-1240. DOI: 10.1016/j.rser.2011.08.014.

[27] Weron R. Electricity price forecasting: A review of the state-of-the-art with a look into the future[J/OL]. International Journal of Forecasting, 2014, 30(4): 1030-1081. DOI: 10.1016/j.ijforecast.2014.08.008.

[28] Pielow A, Sioshansi R, Roberts M C. Modeling short-run electricity demand with long-term growth rates and consumer price elasticity in commercial and industrial sectors[J/OL]. Energy, 2012, 46(1): 533-540. DOI: 10.1016/j.energy.2012.07.059.

[29] Kipping A, Trømborg E. Modeling hourly consumption of electricity and district heat in non-residential buildings[J/OL]. Energy, 2017, 123: 473-486. DOI: 10.1016/j.energy.2017.01.108.

[30] Yukseltan E, Yucekaya A, Bilge A H. Forecasting electricity demand for turkey: Modeling periodic variations and demand segregation[J/OL]. Applied Energy, 2017, 193: 287-296. DOI: 10.1016/j.apenergy.2017.02.054.

[31] Adeoye O, Spataru C. Modelling and forecasting hourly electricity demand in west african countries[J/OL]. Applied Energy, 2019, 242(November 2018): 311-333. DOI: 10.1016/j.apenergy.2019.03.057.

[32] Bangladesh Power Development Board. Bangladesh power development board[EB/OL]. 2021. https://www.bpdb.gov.bd/bpdb_new/index.php/site/daily_generation.

[33] Mines and Minerals Development Hydrocarbon Unit. Coal sector development strategy (final)[R]. Dhaka, Bangladesh, 2013.

[34] Bangladesh Oil Gas and Mineral Corporation. Annual report 2017[R]. Dhaka, Bangladesh, 2018.

[35] Rahman M. Sustainable exploitation of bangladesh's coal resources: An intractable (?) policy dilemma[M]. Dhaka, Bangladesh, 2012.

[36] Kotikalapudi C K. Corruption, crony capitalism and conflict: Rethinking the political economy of coal in bangladesh and beyond[J/OL]. Energy Research & Social Science, 2016, 17: 160-164. DOI: 10.1016/j.erss.2016.05.001.

[37] Masud M H, Ananno A A, Arefin A M E, et al. Perspective of biomass energy conversion in bangladesh[J/OL]. Clean Technologies and Environmental Policy, 2019, 21(4): 719-731. DOI: 10.1007/s10098-019-01668-2.

[38] Huda A S N, Mekhilef S, Ahsan A. Biomass energy in bangladesh: Current status and prospects[J/OL]. Renewable and Sustainable Energy Reviews, 2014, 30: 504-517. DOI: 10.1016/j.rser.2013.10.028.

[39] Staffell I, Pfenninger S. Using bias-corrected reanalysis to simulate current and future wind power output[J/OL]. Energy, 2016, 114: 1224-1239. DOI: 10.1016/j.energy.2016.08.068.

[40] Pfenninger S, Staffell I. Long-term patterns of european pv output using 30 years of validated hourly reanalysis and satellite data[J/OL]. Energy, 2016, 114: 1251-1265. DOI: 10.1016/j.energy.2016.08.060.

[41] Renewables.ninja. Renewables.ninja[EB/OL]. 2021. https://www.renewables.ninja/.

[42] Central Electricity Authority India. Perspective transmission plan[R]. New Delhi, India, 2016.

[43] Wijayatunga P, Chattopadhyay D, Fernando P N. Cross-border power trading in south asia: A techno economic rationale[R]. Manila, Philippines, 2015.

[44] Komiyama R, Fujii Y. Assessment of massive integration of photovoltaic system considering rechargeable battery in japan with high time-resolution optimal power generation mix model[J/OL]. Energy Policy, 2014, 66: 73-89. DOI: 10.1016/j.enpol.2013.11.022.

[45] Komiyama R, Fujii Y. Optimal integration assessment of solar pv in japan's electric power grid[J/OL]. Renewable Energy, 2019, 139: 1012-1028. DOI: 10.1016/j.renene.2019.02.130.