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Impact of COVID-19 on dispatch and capacity plan: A case study for Bangladesh

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ABSTRACT

COVID-19 highlights impact of sudden and sustained periods of low demand that may have major ramifications for financial viability of utilities. However, these effects may be mitigated to some extent through efficient management of dispatch, adjustment of capital outlay for committed capacity and provides an opportunity to reshape longer term capacity development. These issues are particularly critical for developing countries like Bangladesh where the demand shock was acute from avg. 10 % per-annum (pa) to (~)12 % over April-June 2020. This analysis shows how Bangladesh can significantly curtail expensive liquid fuel based generation dispatch, eliminate the use of expensive peaking capacity and even delay some of its capacity addition for the intervening period up to 2025. Prospects of using Battery storage to manage evening peak at the wholesale level have been explored in the analysis and it demonstrates such investments in the present demand scenario is not economic. On the other hand, a more balanced import-export regime with neighboring countries may be beneficial to manage the seasonal capacity surplus that is likely to grow over the next five years.

1. Introduction

COVID-19 had a major impact on electricity demand worldwide beginning with a significant low demand shock during the initial lockdown that brought a major share of industrial and commercial activities to a standstill. Such shocks can translate into financial hardship for utilities due to lower sales and non-payment issues. On the other hand, lower demand can also present opportunities to cut back on expensive peaking resources, delay addition of capacity in the short to medium term and reshape long-term capacity plan.

1.1. COVID-19 impacts on demand and supply in Bangladesh

The COVID-19 impact on Bangladesh has been recorded officially at the end of March 2020. Demand dropped sharply over April-June 2020 (Fig. 1). Lower demand has resulted in considerable cost reduction along with some other critical factors. At present Bangladesh has more than 30 % installed capacity based on liquid fuel that contributed 13 % of its last fiscal year’s 71.4 TW h generation (Bangladesh Energy Regulatory Commission (BERC), 2020). Lower demand coupled with a drop in Heavy Fuel Oil (HFO) price from BDT 44/Litre (USD 0.5/litre) in Fiscal Year (FY) 2020 to BDT 40/Litre (Corporation, 2020) brought significant relief in terms of liquid fuel bills. From Figs. 1 and 2, it is apparent that the demand growth has reduced sharply during the summer of 2020, consequently diminishing the burden of liquid fuel-based peak generation during April to June 2020 (Power Grid Company of Bangladesh, 2020). By the end of June, it has been envisaged that the Government managed to save more than BDT 4.5 Billion primarily due to the lower share of liquid fuel in its energy mix during the last quarter of the FY 2019–20 (Bangladesh Power Development Board (BPDB), 2020). This helps to reduce the gap between supply cost and Bulk Sale Tariff (BST) which stands currently at BDT 0.47/kWh (Chattopadhyay and Bank, 2018) requiring an annual subsidy of BDT 36 billion.

Although Bangladesh confronted a low demand shock during the last quarter of FY 2020, demand has rapidly caught up at the start of the current FY as can be seen from Fig. 2(c). Nevertheless, the demand shock was about (~)10 % in comparison to the projected quarter four of FY 2020 demand, although still higher than the demand in quarter four FY 2018 (see Fig. 1).

Underutilization of power plants makes the SINGLE BUYER entity to pay a lower capacity payment to individual power producers. The capacity payment in FY 2018 was more than BDT 63 Billion, which jumped
to more than BDT 89 Billion in FY 2019 (Star, 2020). Likewise, Fig. 3 shows during April–June which is usually a high demand period in Bangladesh, oil-based generation in the fuel-mix dipped considerably, albeit demand and hence oil-based generation picked up since then.

1.2. Key issues

The cumulative financial burden has become a key concern for the Power Sector planners. The import cost for petroleum has significantly increased in recent years, which was as high as USD 4.5 billion in FY 2018 and USD 4.1 billion in FY 2019 (Star, 2020). However, during the COVID pandemic, the decline in the prices of crude oil and petroleum products triggered a partial relief for the utility in depressing its import payments for primary energy. Global drop in liquid fuel prices and subsequent policy level implications in Bangladesh along with the pandemic impact perceptibly made the power system planners rethink capacity expansion planning to reshape the optimal generation fuel-mix in the foreseeable future. Bangladesh planners may have an opportunity to adopt a policy of gradually phasing out less-efficient old power plants and expensive liquid fuel-based power plants. Such a policy would also need to consider other challenges inter alia, the depleting gas resource and financial as well as environmental toll for the upcoming coal-based power hubs. In this paper, a short-term dispatch analysis framework is used to analyze the impact of COVID-19 demand during FY 2019–20 and its ramifications for FY 2021–25 including reduction in liquid fuel dispatch and new Coal/LNG capacity that may be considered for deferral.

2. Methodology

A MIP based modeling study based on the World bank Electricity Planning Model (EPM) (Chattopadhyay and Bank, 2018) has been used for this analysis to extract the optimal generation options for the Bangladesh power system within the scope of economic analysis. The analysis extends previous studies (Bangladesh Oil, 2020; Islam et al., 2020), with updated and expanded power system of Bangladesh and with the unprecedented COVID-19 impact analysis. This analysis covers the following analytical components:

- **Hourly Dispatch Model** is used to meet the demand for each hour of FY 2019 – FY 2020 in Bangladesh (divided into two zones – East and West – with a transfer limit of 1,200 MW).
- **Two Dispatch Scenarios** have been analyzed in this paper:
  - **ECON**: economic dispatch that largely reflects physical limits on domestic gas availability, minm and maxm limits on utilization. This may mean some of the surplus generation capacity never gets used.
  - **COLN**: a scenario where we impose minimum generation requirement on Coal and LNG.
- **Demand Scenarios**: We have used the following annual growth rates for Base (PSMP2016), High (an elevated growth rate in light of PSMP2016) and Low [authors’ estimation where demand keeps low due to COVID-19, slowly recovering back to Power System Master Plan (PSMP) Base Case growth rate by 2025]. A summary of the scenarios has been shown in Table 1.
  - A domestic gas supply limit has been imposed on an annual basis. The limit, at the low end of 1,000 mmcmd (Million standard cubic feet per day) and as high as 1,100 mmcmd, can severely restrict the ability to use the cheaper domestic gas-based generation facilities. Although gas allocation to the power sector was about 1,130 mmcmd for FY 2019 (Bangladesh Oil, 2020); it has been estimated that the gas allocation may increase to 1,250 mmcmd from generation end and further potential to go up to 1,400 mmcmd that would significantly increase gas generation potential, thus virtually eliminating the need for liquid fuel.

The following provides a brief summary of the Case analysis included the following scenarios:

1. **FY 2019–20**: three cases based on gas resource limits has been shown in Table 2 (Actual with 1,000 mmcmd and minm generation and two optimized cases with 1,100 mmcmd and 1,200 mmcmd with system cost dropping).
2. **FY 2021–25**: four cases based on demand forecast scenarios with short-term capacity expansion planning for the immediate next five fiscal years 2021–25 (Y1–5) has been shown in Table 3. Three demand scenarios based on ECON dispatch scenario (CASE-4,6,7) and another variation of Base where new Coal and LNG have min generation as typically a PPA would impose (CASE-6).

The modeled scenarios are expected to provide insights into:

- **Economic powersystembenefits**: Avoiding the cost of expensive liquid fuel e.g. High Speed Diesel (HSD)/HFO and recovering the Operation & Maintenance (O&M) costs out of the benefits from the seasonal power exchange via Cross Border Electricity Trade (CBET) arrangements; and
- **Short-termcapacityexpansionplanning**: Delaying the candidate coal power hubs by feeding the demand growth from the fullest extent utilization of the efficient power plants among the existing and upcoming ones.
- **Short-termassessment of Battery Energy Storage System (BESS) integration in the system**: The model also runs a short-term dispatch scenario with extendable BESS options to assess the probabilistic scopes of storage system integration for supplementary benefits.

3. Case study for Bangladesh

The EPM short-term model and the dispatch model consider more than 138 nos. existing generating units totaling about 21 GW generation...
capacity. The peak demand is close to 13 GW. A probable list of 40 nos. potential power plants excluding the re-powering facilities (Bangladesh Power Development Board (BPDB), 2020; Power Division, Ministry of Power, Energy and Mineral Resources, 2019) have been considered for short-term capacity expansion planning through FY 2025. Generation cost, a sum of fuel and Variable Operation & Maintenance (VOM) Cost, has been considered to drive the model as per the Merit Order of the generation facilities.

3.1. Modelling results for FY 2019 & FY 2020

The historical generation for FY 2019 & 2020 has been simulated and compared the actual and optimal case scenario in terms of economic benefits. A comparative result of the total generation cost between CASE-1, 2 & 3 has been shown in Fig. 5. Economically Beneficial Optimal-Fuel mix Results for Gas & Oil in FY 2020 has been shown in Fig. 4.

It also shows that, overall utilization of the existing generation fleet of 21 GW installed capacity is considerably low and yet liquid fuel (HFO & HSD) remains to be used for a considerable part of the generation mix. Thus, the model predicts an optimized dispatch could save as much as BDT 20 billion (USD 235 million) in a year, where the CASE-2 could be taken as an ideal optimal fuel-mix scenario with 1,100 mmcfld gas constrains by improving the dispatch of the current generation fleet.

Thus, the modelling outputs suggests that there is quite significant generation cost saving potential from optimal fuel mix out of the existing generation facilities with the primary fuel (gas) constraints. The analysis

![Figure 2](image1.png)

![Figure 3](image2.png)

Fig. 2. Demand Growth Pattern of BD During FY 2019 & FY 2020 [(a) Growth Trend throughout the FY; (b) Growth Trend during APR-JUN timeslot; (c) Monthly Load Factory throughout the FY].

Fig. 3. Generation Fuel-Mix Share of Gas & Oil.
reinforces the results of our previous work (Bangladesh Oil, 2020; Bangladesh Power Development Board (BPDB), 2020) which this analysis updates with more recent data and a system that now has substantially more capacity.

### 3.2. Modelling results for capacity expansion planning 2025

#### 3.2.1. CASE-4 (BASE_ECON)

CASE-4 has been designed to simulate without any Minm or Maxm generation limit for any plant. The aspects of this scenario in the context of capacity expansion and potential utilization of the upcoming generators has been shown in Fig. 6, which shows the potential utilization of the major portion of fuel mix in the installed capacity.

The simulation result shows that about 12.5 GW gas fleet utilization on average remains considerably low (below 60 % in 2025). Coal and LNG also get utilized very little (below 5 % even in 2025). These results clearly demonstrate a high risk of asset stranding looming large in Bangladesh that will significantly increase the financial burden on this sector. With the addition of coal, LNG and gas-based generation facilities in the system, the utilization of 2.6 GW of CBET share remains slightly above 25 % through 2022–25. The low utilization of the LNG fleet amidst the rapid pace of demand growth may trigger a larger cost burden in foreseeable years; which has been illustrated in Fig. 7(a and b). Fig. 7 also illustrates that, during the FY 2024–25 the capacity growth may be slowed down after the committed coal plants become operational during 2022–23. It may be depressed as low as 5 % from this triggering point the overall cost of generation may gradually rise up to 15 % in 2025. The considerably low utilization of LNG is one of the driving factors of this spike in generation cost. The reliance on liquid fuel base generation may reduce to nearly zero as shown in 5–10 Tk /kWh tariff share in Fig. 7 (b).

#### 3.2.2. CASE-6 & 7 (HIGH_ECON vs LOW_ECON)

A comparative demonstration of CASE-6 & 7 has been shown in Fig. 8.

The model shows the low utilization risk for brand new coal and LNG assets even for HIGH and LOW demand scenarios, which is particularly worrying. The LOW_ECON (CASE-7) could be considered as the more realistic scene after the COVID-19 demand shock, in the near term.

#### 3.2.3. CASE-4 & 5 (BASE_ECON vs BASE_COLN)

These cases impose a minimum utilization limit, namely Min\(^m\) 40 % (for LNG) and 50 % (for Coal) utilization assurance; to mimic the power purchase agreements that will typically require the plants to run – possibly at even higher level than considered in this analysis. While this avoids the stranding risk, running these expensive plants can impose major cost burdens on the system as Fig. 9 demonstrates through a comparison of CASE-4 (BASE_ECON) and CASE-5 (BASE_COLN).

The results show that the cost burden would rise over the years as new capacity and hence minimum generation requirement rises especially for FY 2024–25. CASE-5 results also show that the forced run of Coal based generators may cost the system about BDT 330 billion (USD 3.9 billion) during FY 2025.

#### 3.3. Economics of battery storage at wholesale level

We have also set the model to test the economics of BESS at the wholesale level. BESS for a developing country requires careful

![Fig. 4. Economically Beneficial Optimal-Fuel mix Results for Gas & Oil in FY 2020.](image-url)
consideration as these are still relatively expensive investments for which there is no market-based mechanism in most countries, including Bangladesh (Islam et al., 2020). At a wholesale level, the ability for the BESS to earn anything beyond energy arbitrage is limited. For instance, there is no compensation for frequency control ancillary services and as such we have focused on the ability for BESS to reduce reliance on expensive HFO based generation during evening peak. The analysis used hourly dispatch for FY 2021–2025 using the Power System Master Plan (PSMP) 2016 baseline growth rate (~9 % pa). We have considered 100 MWh in East and West regions of Bangladesh at a total cost of USD 60 million (i.e., USD 300/kWh). The dispatch analysis is augmented with a storage model that determines how the BESS would be used to charge during off-peak hours when the marginal cost is low, and discharge when high-cost gas/HFO plants are used. The EPM modeling
methodology for storage is discussed in (Islam et al., 2019). If 100 MWh is used every day for one full cycle, it will annually consume \(365 \times 100\) MWh or 36.5 GWh. Table 4 reports the annual BESS usage in GWh and also as a % of this maximum 36.5 GWh level. While West Bangladesh seems to find reasonable use of the BESS, East Bangladesh barely uses it following the first two years although it has 70 % of the national load. This is not surprising considering the surplus capacity in the system and also the fact that gas availability in this system is constrained which does not allow any cheap energy in the system to be used for charging the BESS. Benefits of BESS in terms of reduced system cost amounts to only USD 1.3 m over a five-year period, i.e., only USD 0.26 m benefit compared to USD 8.15 m in annualized cost. Economic Internal Rate of Return (EIRR) even assuming the final year highest benefit continues for another 15 years is strong negative (-) at 12 %.

Although BESS is shown to have negative economics at a wholesale level, it is contingent on the current state of surplus in part caused by depressed demand condition due to COVID-19. The situation can be quite different for the distribution/customer end BESS where storage can reduce load shed for commercial and industrial users due to constraints in the transmission and distribution system.

4. Concluding remarks

Power system planning usually tries to address the challenge of meeting high demand growth rate in the face of investment constraints in a country like Bangladesh. However, demand shocks like the ones that happened during the Asian crisis in the late nineties, the global financial crisis in 2009, and COVID-19 in 2020 are reminders of the undeniable fact that there is also a risk of overbuilding and temporary asset stranding. The analysis presented here shows that Bangladesh is a particularly strong case with significant capacity overhang for the next five years. Unfortunately, a significant part of it also happens to be expensive Coal and LNG plants that would run on imported fuel. In our Base Case, that in fact assumes a very quick recovery from COVID-19 from 2021 to resume demand growth at 9 % pa in-line with the planned growth, still sees brand new Coal fleet of 9 GW expected to be utilized below 50 % over the next five years, dipping as low as 34 % in 2023. Brand new LNG based plants have a far worse utilization rate as low as 5 % in some years, effectively rendering these plants to be stranded for most part except for a few summer days in an economic dispatch scenario. This is in fact true even if we take the most aggressive high demand growth scenario in which Coal utilization lifts slightly to 55 % on average and that for LNG to 6 %. In reality though, both Coal and LNG plants will have minimum take-or-pay contracts. This is worse because expensive Coal/Gas plants running on imported fuel will run ahead of cheaper gas plants and power import that will cost the country in excess of USD 1 billion (0.4 % of GDP in 2019) in operational cost during FY 2024–25.

This analysis highlights the need for capturing sharp downturn in demand in long term planning as these events do happen almost once in every decade. There are ways for Bangladesh to manage the situation as some of the constructions and contract negotiations for plants can be delayed or canceled. The savings in investment and dispatch costs can be usefully reallocated to transmission and distribution system upgrades.
that are needed to improve reliability of supply to customers. A comparative analysis between the investment cost for new power plants vs upgradation cost of the transmission and distribution infrastructure however, may need to be analyzed as an extension of this study. We also recognize the importance of flexibility in the system that could be enhanced for Bangladesh to be more strongly connected to its neighbors including India, Myanmar and have access to Nepal and Bhutan through its participation in a South Asia wide regional electricity market. This may enable Bangladesh to manage its surplus generation and also have access to much cheaper electricity for meeting its summer peak. Last but not the least, a reliance on baseload Coal is not only expensive but also has serious carbon and local pollutant emissions that could be avoided through cross-border power trade, including solar/wind/hydro generation from its neighboring systems.

Disclaimer

The opinions and views presented in this academic research paper are the own views of the Authors and do not necessarily represent the views of the International Bank for Reconstruction and Development/World Bank or its affiliated organizations or the Bangladesh Power Development Board.

Author contribution

Md. Eliasinul Islam: Conceptualization, Resources, Data curation, Formal analysis, Visualization, Writing - original draft preparation.
Md. Monower Zahid Khan: Data curation, Investigation, Resources, Writing - review & editing.
Deb Chattopadhyay: Methodology, Software, Data curation, Validation, Supervision, Funding acquisition, Writing - review & editing.
Jari Väyrynen: Validation, Supervision, Funding acquisition, Writing - review & editing.

Declaration of Competing Interest

The authors report no declaration of interest.

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