

A bottom-up financial model of power generation in Bangladesh¹

1. This note describes a financial model of the power sector in Bangladesh developed by the World Bank to assess the impact of different policy interventions on sector finances. The model was built from the bottom up, on the base provided by the planning model used by the Bangladesh Power Development Board (BPDB). It is hoped that making this model available will allow the Government and development partners to have a common framework for analysis and develop a common understanding of what needs to be done to assure the sustainability of the sector.

Summary

2. In this note, the model has been used to forecast power sector subsidy requirements taking as a starting point the power generation expansion plan of the Government of Bangladesh (GOB). This is expected to assist the off-taker, BPDB, in estimating the financial impact of different power generation options, among other scenarios. The model forecasts the sector financial situation under different tariff and cost assumptions – it uses cost data obtained from BPDB for each plant, forecasts for global fuel prices, and makes a number of macroeconomic assumptions. The GOB's power generation expansion plan is quite ambitious and the note presents the subsidy requirements under different generation expansion scenarios.

3. Taking 2016 as the base year, the model makes projections for 2017-2025². In the baseline scenario, based on the power generation expansion plan of GOB, cost of power supply to end-users is projected to rise from Tk7.51/kWh in 2016 to Tk 9.25/kWh by 2020 and over Tk12.51/kWh by 2025. The increased costs are the result of fuel substitution from low-cost domestic natural gas to more costly options (coal, LNG, liquid fuel) and an assumed higher cost of domestic natural gas (to bring parity to the market). Currently, electricity prices to end-users average around Tk6.39/kWh, resulting in an annual deficit of Tk42 billion (US\$538 million) in fiscal year 2016. End-user prices of electricity have seen gradual adjustments with the average price increased by about 60% since 2009 in nominal Taka terms (40% increase in nominal dollar terms).

4. Going forward from 2016, electricity price adjustments will need to continue in the near-term to match the increased costs of generation. A tariff increase of 8% per year will be required to achieve break-even by 2020 (i.e. tariff sufficient to cover costs and therefore no budget transfer required). A 12% increase in tariff per year will result in break-even by 2018. Bangladesh is expected to import LNG to supplement declining domestic gas production and the import of LNG will increase the average price of gas supplied to the sector, causing a rise in cost of power procured. The expectation is that domestic gas prices will converge in the long-run to LNG import prices. This means that in the future the price of gas will exceed that of coal. This change has severe implications for power planning as the shift in fuel prices alters the economics of generation. The baseline scenario in the model reflects the current situation of

¹ Prepared by Zubair Sadeque (Senior Energy Specialist) and Miklos Bankuti (consultant) in the EEX Global Practice at the World Bank. The authors gratefully acknowledge comments from Sudeshna Ghosh Banerjee (Practice Manager) and Raihan Elahi (Lead Energy Specialist) at the World Bank. This paper is part of a larger analytical effort examining the performance of the energy sector in Bangladesh led by Sheoli Pargal (Lead Economist).

² All years are July-June fiscal years.

domestic gas (priced significantly below international levels) being used as the primary fuel for power generation, and an ambitious plan of GOB for adding low-cost coal-based large power plants. The share of coal is assumed to go up from less than 2% today to 40% by 2025 with the share of natural gas (including LNG) dropping from the current 65% to 45% by 2025.

5. The model's projections also show that coal generation will be more expensive than imported electricity, and as such, increasing power imports should be a policy priority. Currently, Bangladesh imports 500MW of power from West Bengal at a cost of 5.61Tk/kWh. In contrast, the operating coal plant supplies power to the grid at an average cost of 5.93Tk/kWh. Projections show that the cost of imported power will remain lower than the cost of coal-fired generation. It should be noted that Bangladesh has been able to develop 500MW of import capacity in a relatively short time with an additional 600MW entering service by the end of 2017 while the construction of coal plants remains in planning stages.

Background

6. **Bangladesh has relied mainly on domestic natural gas for power generation, the shortage of which has prompted a need to look for costly alternative fuels.** Domestic natural gas was the dominant fuel for power generation accounting for almost 90% of power generation for most of the history of Bangladesh until recently³. Since the beginning of last decade, the country started to face gas shortages due to decades of under-investment in gas exploration⁴. This has prompted policy makers to look for alternative fuel; coal and Liquefied Natural Gas (LNG) in the medium to long term, and liquid fuel-run rental plants as an interim stop-gap fuel. In 2010, GOB embarked on an ambitious generation expansion plan that called for a three-fold increase in power generation capacity in 5 years (from about ~4,300MW in June 2010 to 11,500MW by 2015), and to 20,000MW by 2021⁵. The 2010 plan envisaged an ambitious plan to introduce coal in the fuel mix (25% share by 2015) followed by liquid fuel (20%). The plan was largely met by 2015 (installed capacity reaching 10,939 MW in 2015- figure 1), although the capacity addition came mostly from liquid fuel (30% of the capacity mix)⁶. During the later updates of the road map, LNG was planned to be introduced by 2018 to improve energy security. The implication of all these

³ Coal represented for 4% of power generation, hydro 1.6%, and liquid fuel about 5%.

⁴ The on-shore areas already relatively well-explored, the country is to start looking for gas resources in the deep sea blocks, which are more expensive and require technological know-how that the national exploration company does not have. After the maritime boundary issue was settled with neighboring Myanmar and India, GOB has recently started to focus on inviting International Oil Companies (IOCs) to explore in deep sea blocks. To align the terms of the Production Sharing Contracts (PSCs) with the current market, GOB is reviewing the PSC terms and conditions. Production of any gas from the deep sea blocks will take time and is unlikely to materialize within the planning horizon of 2021.

⁵ Towards Revamping Power and Energy Sector: A Road Map; June 2010 by Finance Division, Ministry of Finance, Government of Bangladesh. The generation expansion plan has since been updated regularly with the latest plan calling for generation to be increased to 24,000MW by 2021 (June 2016).

⁶ The estimated coal reserve in Bangladesh is 3.3 billion tonnes (www.bcmcl.bd), most of which remain un-utilized. One coal mine (Barapukuria) started production in 2006 with a current production of 1 million tonnes per year, 65% of which is used as fuel in a 250MW power plant. There is a sensitive public debate over the method for coal extraction; open pit technology will have large-scale resettlement issue in this highly densely populated country while coal mining has its associated health and safety risks along with low productivity issue due to geological structure. GOB policy has been to add coal capacity based on imported coal until the domestic coal development issue is settled.

has been that the projected cost of power generation is to rise from Tk7.51/kWh in 2016 to Tk 9.25/kWh by 2020 and over Tk12.51/kWh by 2025.

7. **Despite the increasing generation capacity, supply is not adequate to catch up with the rapid increase in demand from accelerating access.** This has limited energy consumption and economic growth. GOB has been rapidly increasing grid access in recent years with 3.8 million new connections in rural areas in last FY alone. Access to electricity is currently about 80 percent⁷. Those with grid connection experience supply disruptions due to shortage in generation of electricity and bottlenecks in the grid network. Annual per capita energy consumption of Bangladesh is relatively low at 370 kWh, compared to 1,010kWh for India and 2,600kWh for China. Bangladesh is ranked 106th on Global Competitiveness Index, out of 128 countries, and 110th on quality of electricity supply⁸. In the latest Doing Business Indicator, Bangladesh is ranked 176 out of 190 economies of the world and in the indicator of “Getting Electricity”, it is ranked the fourth lowest out of 190 economies⁹.

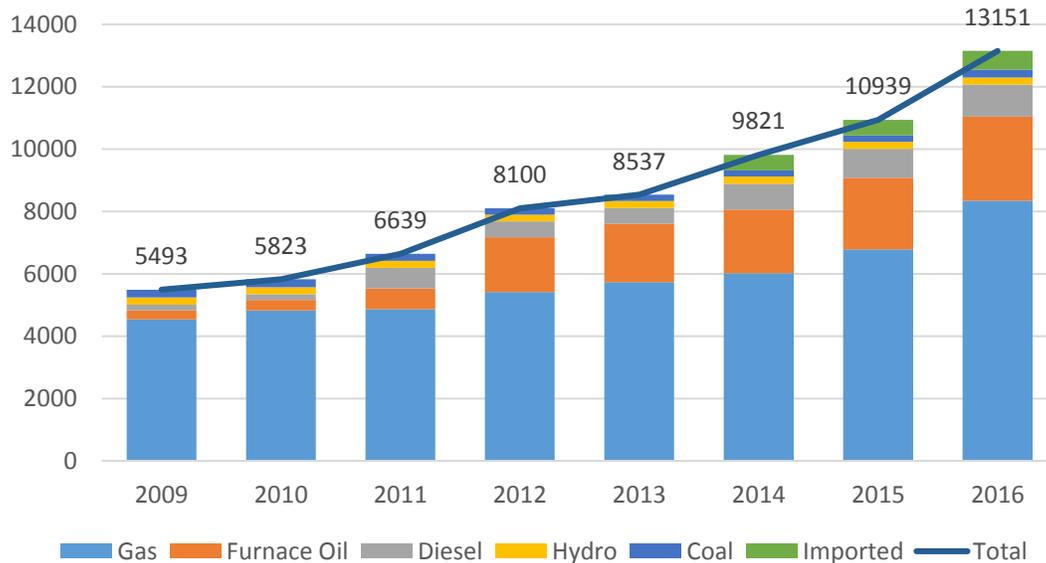
8. **As a short-term solution to persistent power generation shortages, expensive liquid fuel-run plants were introduced in 2010.** Delays in commissioning large base load plants are resulting in continued dependence on liquid fuel-run plants (Figure 1). The liquid-fuel run plants were added to the fleet starting in 2009 as short term measures to meet the gap until the planned large gas-based and coal-based plants come online. Persistent delays in commissioning the large base load plants however have resulted in continued dependence on the liquid fuel plants for power generation. Gas capacity has been added between 2009-16 despite the shortage of gas; however, as a measure to address gas shortages, liquid-fuel plants were also added. Today, a quarter of total generation is coming from liquid fuel-run power plants while natural gas accounts for about 65% of power generation and the rest from hydro (2%), coal (2%), and more recently imported power from India (5%). The liquid fuel-run plants are the most expensive. Compared to about Tk 3/kWh of fuel cost for gas based plants (depending on plant efficiency and based on the current price of gas for power generation at US\$1/mcf), the fuel cost from furnace oil and diesel are Tk 20/kWh and Tk 28/kWh respectively.

⁷ This includes both grid and off-grid (solar home systems) connections. About 4.5 million solar home systems are installed in the country with some of them recently being connected to the grid network.

⁸ World Economic Forum: The Global Competitiveness Report 2016-2017

⁹ The World Bank Doing Business 2017: Equal Opportunity for All; October 2016

Figure 1: Installed Capacity by Fuel Type (MW)

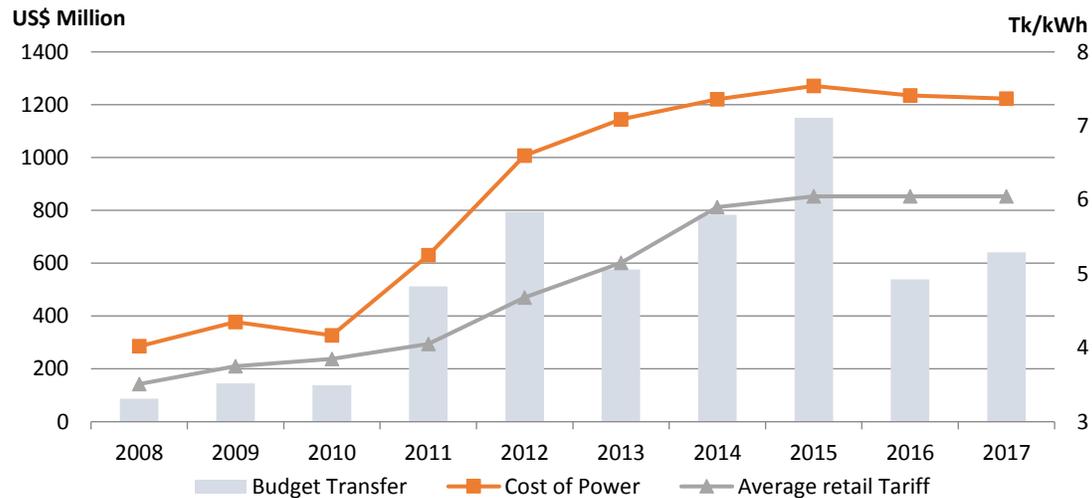


Source: Bangladesh Power Development Board (BPDB) Annual Reports.

9. **Tariff increases have not kept pace with increased electricity generation costs resulting in large deficit in the sector (Figure 2).** When GOB embarked on the short-term measures of introducing liquid fuel-run plants in 2009 for mitigating the persistent power generation shortages, it decided that the higher costs of the liquid fuel-run plants would not be fully transferred to the consumers. An annual budgetary transfer cap of BDT 50 billion (US\$640 million in current dollar terms) was decided to be allocated to the off-taker Bangladesh Power Development Board (BPDB) to meet these short-term costs. A tariff trajectory was planned that will raise the average tariff gradually to be at par with the long-run costs of large base-load plants while the annual budgetary transfer covered the short-term liquid-fuel run plants¹⁰. The annual budgetary transfer increased from Tk 6 billion (US\$87 million) in 2009 to a peak of almost Tk 90 billion (US\$1.15 billion) in 2015 before coming down to Tk 42 billion (US\$538 million) in 2016. Retail tariff was increased by about 60% during the period. The recent decline in fuel oil prices has helped to reduce the recent budgetary transfer requirements.

¹⁰ To raise tariff, utilities are required to submit tariff applications to the independent regulator Bangladesh Energy Regulatory Commission (BERC). BERC decides on the tariff order following a cost-plus regulation through proper scrutiny of the tariff applications and a public hearing process. Such scrutiny involves reviewing the costs and efficiency of the utilities and only reasonable costs (within the efficiency targets) are included in tariff calculations. In order for not transferring the full cost of liquid fuel-run plants to consumers, the bulk supply tariff (the tariff at which distribution utilities buy power from the off-taker BPDB) is kept at below cost and the annual budgetary transfer makes up for the shortfall.

Figure 2: Direct Deficit to the sector (US\$ Million)



*2017 deficit figure is the budgeted amount of BDT50 billion.

10. **The deficit is based on the subsidized costs of fuel used for power generation, and the actual deficit will be much higher if the market prices of fuel are taken into account.** The input fuel costs are administered by GOB and are set at sometimes much below the real market prices. The domestic prices of liquid fuel are not automatically adjusted to the international market although most of the liquid fuel are imported. The budgetary transfer to BPDB therefore does not reflect the full financial deficit from liquid fuel run plants. The natural gas price for power generation at US\$1.05 per thousand cubic feet (mcf) is subsidized¹¹. GOB is purchasing gas from the international oil companies under Production Sharing Contracts at around US\$1.3/mcf.¹² The price for natural gas used for power generation in the neighboring India and Pakistan were about US\$5/mcf (as of 2011)¹³. The liquefied natural gas (LNG) sells for around US\$8/mcf¹⁴ in the international market. As explained later, the projections used in this analysis are based on the current subsidized fuel prices; if the cost of electricity were to reflect the true cost of all inputs, the projected cost of electricity and the resulting sector deficit, would be significantly higher.

11. **The sector has evolved from a vertically integrated single utility to a partially unbundled sector with an aim to improve sector performance.** BPDB was the vertically integrated utility, which has since been unbundled into several generation companies, one transmission company, and several distribution companies. BPDB currently operates about half of the power generation units while it purchases power from three generation companies and from the private sector as the single off-taker. Power Grid Company of Bangladesh (PGCB) is the single transmission company carrying power and receiving a wheeling charge for the power transmitted. On the distribution side, the rural cooperatives (PBSs) under the Bangladesh Rural Electrification Board (BREB) distributes about 40% of the power, Dhaka Power

¹¹ BEREC has issued a tariff order to raise the gas price for power generation to increase by 6% effective from March 1, 2017 and another 6% effective from June 1, 2017.

¹² MIS. Petrobangla, 2015.

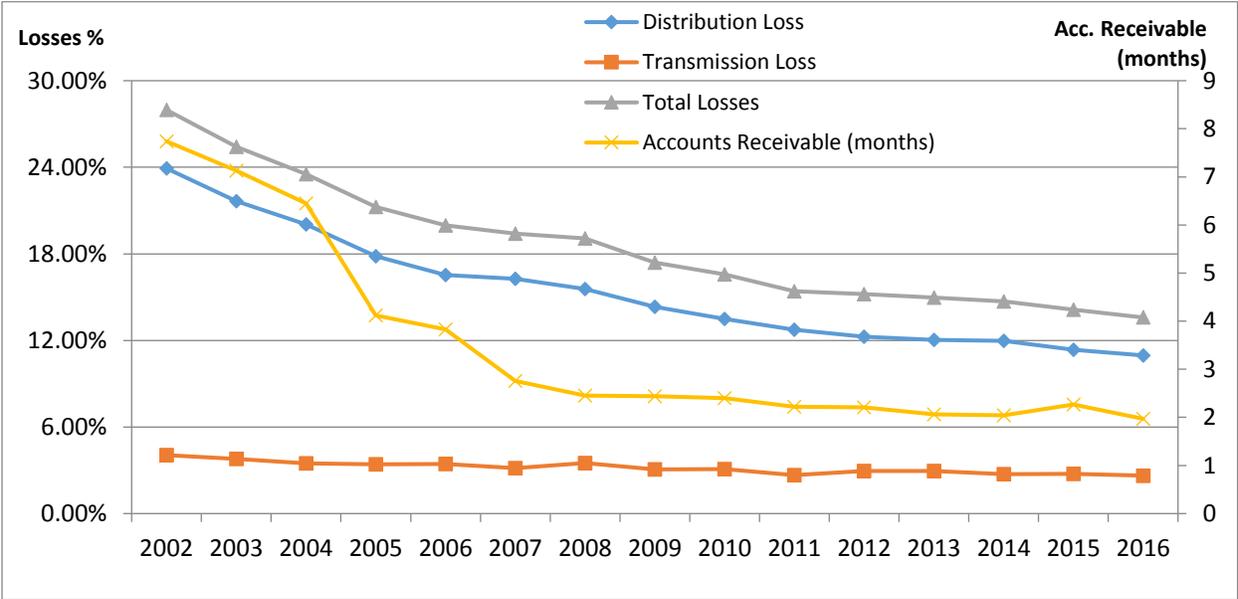
¹³ Bangladesh: Tariff Reform and Inter-sectoral Allocation of Natural Gas: Asian Development Bank, 2013

¹⁴ The landed price of LNG in India dropped to US\$8.64/mcf in DATE?

Distribution Company (DPDC) (19%), Dhaka Electric Supply Company (DESCO) (11%), West Zone Power Distribution Company (WZPDCL) (6%) while the rest (25%) is distributed by the BPDB distribution zones.

12. **With the sector unbundling efforts and increased focus on addressing technical and commercial losses, the overall sector performance has shown remarkable improvements with aggregate systems losses coming down to half from that of the 2002 level (Figure 3).** Distribution losses came down from 24% in 2002 to less than 11% currently while the transmission losses came down from 4% in 2002 to 2.63% currently. The collection efficiency also improved significantly as is evident from the accounts receivable coming down from about 8 months of sales equivalent to a little over 2 months currently. Amongst the utilities, BREB has the highest system losses (11.2%) while DESCO the lowest (8.03%).

Figure 3: Sector Performance



Source: Power Cell

The Model

13. **This section presents key features of the detailed financial model developed for Bangladesh’s power sector.** The model projects electricity demand, generation, and cost over the near- and medium-term based on the generation expansion plan and other inputs. It projects electricity production based on technical potential production from existing and planned power plants, and then imposes fuel availability, demand pattern, and other constraints. It projects demand based on current estimated demand and demand growth relative to GDP and balances this with available supply to project electricity sales. It calculates a cost-recovery tariff for the sector on a “cost-plus” basis following the principle that all reasonable costs (based on specified efficiency levels) are passed on to consumers¹⁵.

¹⁵ As discussed previously, the high costs of liquid fuel run plants were deemed as temporary and government decided to cover such costs with budgetary transfer, and therefore such costs are not passed on to consumers.

14. **The model's primary generation input is the generation plan developed by BPDB.** The generation plan specifies all existing and planned plants, including their commercial operation dates and planned retirement dates, and their key characteristics, including fuel type, installed and derated capacity, potential plant load factor, thermal efficiency, and fixed and variable contract costs. The model uses this to project potential electrical output and associated fuel usage each year. It combines the contract cost data with fuel price projections to calculate the cost for different levels of plant production. It should be noted that the model does not optimize system-wide electricity generation based on marginal cost of the plants¹⁶.

15. **Other key inputs are projections of electricity demand, transmission and distribution losses, and transmission and distribution costs.** The model projects demand by using an assumption about current electricity demand (which, given the current supply constraints, exceeds actual sales) and how that will evolve relative to projected GDP growth. It allocates demand among electricity utilities by assuming the recent sales mix. The model also has an option of projecting demand based on current sales and past sales growth; this option is not exercised in this note, however, as it is most relevant in contexts where available supply is sufficient to fulfill demand (which is currently not the case in Bangladesh). The model projects transmission and distribution losses based on current loss levels and GOB targets for future losses. It combines this with the demand projections to calculate the amount of generation required to satisfy demand. Finally, it projects transmission and distribution costs based on projected sales, assuming that past financial trends continue.¹⁷

16. **The model combines the supply, demand, and cost inputs to project sales, generation, and cost.** The model compares its potential supply projections with its calculation of the amount of generation needed to satisfy demand and curtails whichever is higher until they are equal. If supply is greater than demand, the model curtails supply equally for plants by as much as necessary to meet demand. If demand is greater than supply, the model curtails sales from all distribution companies equally until the amount of generation required for projected sales equals potential supply. Once it reaches a final, balanced projection for plant output, the model calculates the final cost of generation, transmission, and distribution per unit of electricity produced. As discussed previously, a merit-order dispatch projection is beyond the scope of the model and it relies on the existing dispatch data for projections.

17. **BPDB's generation plan envisages adding about 12.5 GW of capacity between 2017 and 2025 – almost doubling the current installed capacity of 13.1 GW.** Nearly half of that capacity is expected from natural gas (including from LNG) and 40% of the capacity addition is expected from coal. The coal power plants are expected to initially run on imported coal, while a single 200MW existing coal plant uses the small amount of domestic coal available. Nearly 5% of the capacity addition is expected from electricity imports. Through 2025, the generation plan also calls for retiring about 5,000 MW of old gas plants and allowing the rental contracts to expire for about 1,500 MW of diesel and furnace oil plants (Figure 4). The

¹⁶ Such optimization, or “merit order dispatch” is not practiced by the off-taker BPDB currently because of bottlenecks in the network (that restricts lower cost power to be sent to certain part of the network and forces use of localized higher cost power) as well as lack of automation in system dispatch (that would have allowed system dispatch to prioritize low cost plants over higher cost plants). The model uses the generation plan of BPDB that takes into account these constraints. A Bank loan has been provided to support the Government in addressing these systemic issues.

¹⁷ Specific financial trends considered are the return on gross fixed assets (GFA), repair and maintenance as a percent of GFA, depreciation rate, works-in-progress completion rate, growth of staff expenses as a percent of sales growth, other expenses as a percent of staff expenses, and other operating revenue and non-operating income as a percent of total revenue requirement.

timeline for the large coal fired plants to come online or for LNG import is highly ambitious given the current status of these projects. Later in this note, several scenarios have been presented with a more realistic assumption for likely availability of these plants.

Figure 4: Capacity Added by Year (MW)

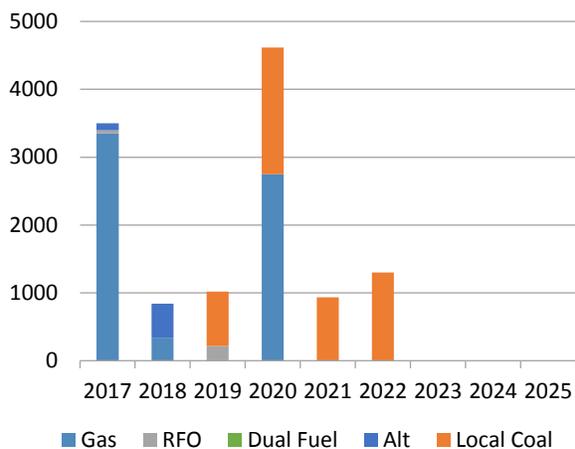
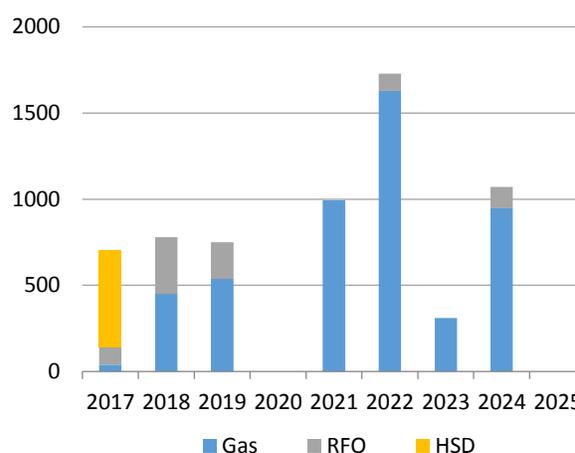


Figure 5: Capacity Retired by Year (MW)



18. **The model takes the current generation costs for each plant as the basis for forecasting the cost of electricity while assumptions for planned projects are based on industry standards.** Generation costs are based on variable and fixed costs for each state-owned and operated plant as reported by BPDB. For private plants, the model uses the fixed and variable costs charged by the operators, which are defined in the power purchase agreements. For newly built plants that should come online during the forecasts period, standard industry assumptions are made on the capital and operating costs and the operational parameters of the plant. The total fuel cost is calculated based on fuel price projections and the heat-rate of each plant.

Table 1: Cost Assumptions for New Build Plants

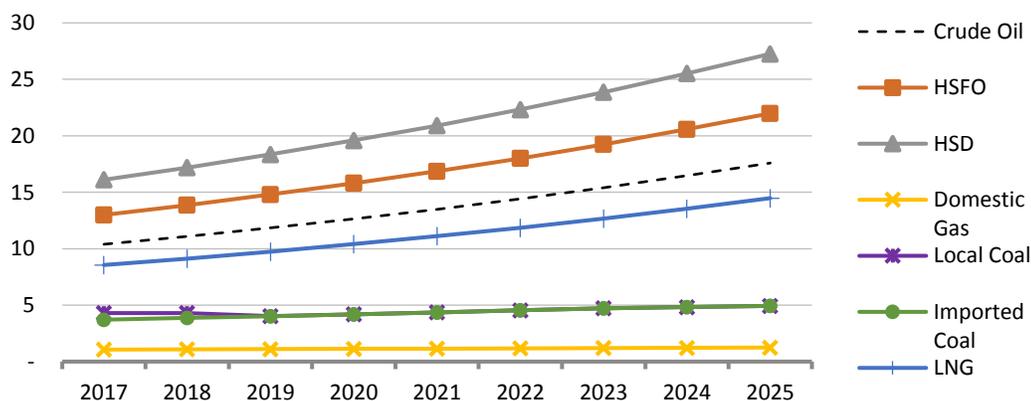
		CCGT	GT	Diesel	Fuel Oil	Coal - Dom	Coal - Imp
Capital Cost including IDC	\$/kW	1167	880	935	935	1767	2280
Price Escalation Rate	%	2%	2%	2%	2%	2%	2%
IDC as % of total inv.	%	0.15	0.15	0.15	0.15	0.15	0.15
Fixed O&M	\$/kW/month	2.5	1.5	2.5	2.5	3.25	3.25
Net Thermal Efficiency	%	51%	35%	35%	35%	41%	41%
Variable O&M	\$/MWh	1.5	1.5	1.5	1.5	2	2
WACC	%	10%	10%	10%	10%	10%	10%

19. **The model adjusts prices for inflation and changes in exchange rates over the forecast period.** Inflation is expected to be 6% per annum on average over the forecast period while US dollar costs are expected to rise by 2% per annum. Forecasts for GDP growth and inflation were based on the World Bank's Development Indicators. A basic assumption in the model is that purchasing power parity will drive the

growth of the Taka/US\$ exchange. This means that exchange rates will grow according to the relative changes in aggregate price levels. Because of higher inflation in Bangladesh, the value of the Taka is seen to depreciate from Tk80/US\$ in 2015 to Tk117/US\$ by 2025.

20. **With the exception of local gas and a small amount of imported coal, fuel prices are assumed to be driven by international trends (Figure 6).** The prices of furnace oil, diesel, and LNG are assumed to be linked to crude oil prices (125%, 155%, and 90%, respectively, on an energy equivalent basis). Global crude oil price has dropped from US\$120/bbl in 2014 to about US\$55/bbl currently. The impact of the drop in oil prices has yet to be felt by consumers in Bangladesh as GOB has not adjusted domestic prices to reflect the decline in oil import prices. The model assumed that prices remain the same until the end of FY2016 and thereafter become adjusted downward to reflect international prices. International oil prices in the model gradually increase over time based on forecasts by the World Bank. Domestic gas remains critically underpriced compared to alternative fuels. This has led to an overreliance on gas for power generation. For the base case scenario, the model assumes that domestic gas prices are adjusted only with inflation, which will still result in its under-pricing. The model has the flexibility of analyzing different gas price scenarios including the scenario where domestic gas prices are gradually adjusted to be at par with international prices. Domestic coal is currently subsidized and is assumed to initially remain at its current price (about US\$108 per ton) until the first imported coal plant comes online in 2018; after which it is assumed the regulated price of domestic coal would be set equal to the delivered price of imported coal. However, the current plan for coal projects to come online by 2018 is unlikely. BPDB will have to make adjustments in its generation expansion plan to reflect the likelihood of delays in coal based projects.

Figure 6: Fuel Prices Projections (US\$/MMBtu)

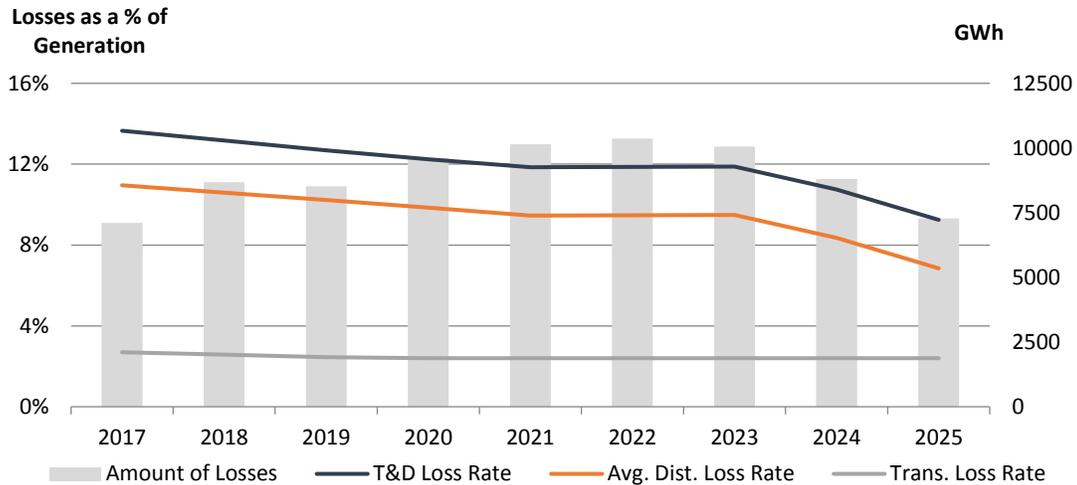


21. **Demand assumptions largely follow the Power Sector Master Plan developed for Bangladesh in 2016.** Demand for electricity is assumed to grow at about 1.03 times the rate of GDP growth (consistent with the draft update of the Power Sector Maser Plan). GDP is assumed to grow by about 7 percent per year. For simplicity, the model does not take into account the price elasticity of power consumption, i.e. the impact of higher prices on demand is not taken into account in the model.

22. **Transmission and distribution loss rates are assumed to continue to fall over the next four years and level out in 2018 (Figure 7).** Transmission losses, currently at 2.7 percent, are assumed to fall to 2.4 percent by 2017. Distribution losses, which currently average 12 percent, are assumed to fall to 9.6% by

2025 as per GOB targets. Recent capital investment has contributed to the improving trend in transmission and distribution losses

Figure 7: Projected Transmission and Distribution Losses



Baseline Scenario

23. **The baseline scenario envisages surplus capacity by 2018 with the introduction of LNG eliminating gas shortages for running the gas-based plants (Figure 8).** Plant load factor is projected to drop until 2017 due to lack of available gas supply to run at full capacity the additional gas plants (Figure 9). As per BPDB plan, once LNG becomes available, plant load factor starts to rise again. As per the demand projections, plant load factor never reaches 59% because by the time LNG becomes available, there is more supply than is needed to meet demand, so there is no need to run plants at more than an average 59% capacity until 2024. This assumption is based on substantial addition in coal generation capacity. By 2022, coal plants should provide 5.35GW of capacity which implies the construction of several new coal plants and the addition of coal import capacity that the country currently lacks.

Figure 8: Electricity Supply and Demand (MW)

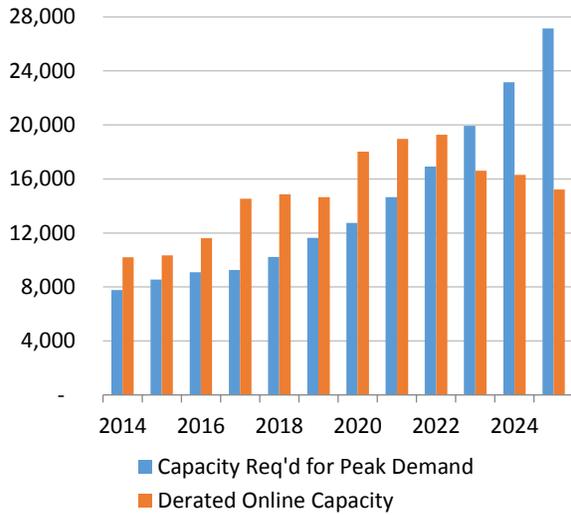
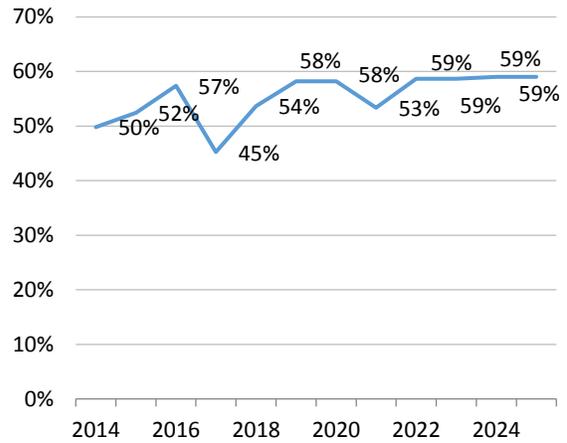


Figure 9: Plant Load factor (%)



24. **The average cost of power supply is expected to increase due to the higher cost LNG and coal in the fuel mix.** With the introduction of imported coal based power generation coming online in 2019, cost of supply rises slightly to about the same level as of 2014. Given the current deficit between tariff and cost, going forward, even if tariff increased with only inflation, there would still be deficit in the range of Tk 50-60 billion annually by the year 2019 (Figure 5). The model assumes that the planned coal generation projects will come online as intended. It should be noted, however, that plans for importing coal and building coal based power plants have been in the development stages for years and delays in these projects is very likely to happen.

Figure 10: Projected Supply Growth as per BPDB Plan

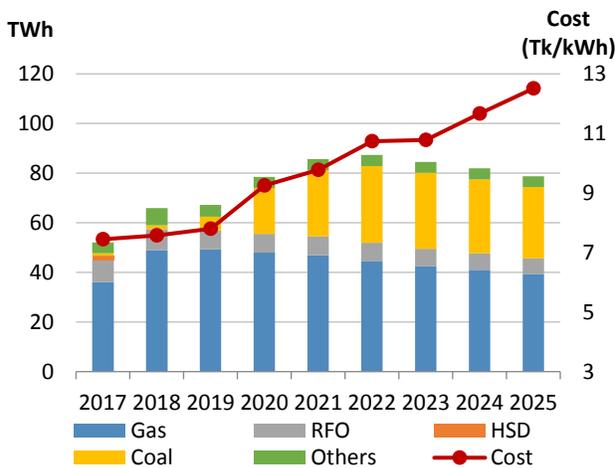
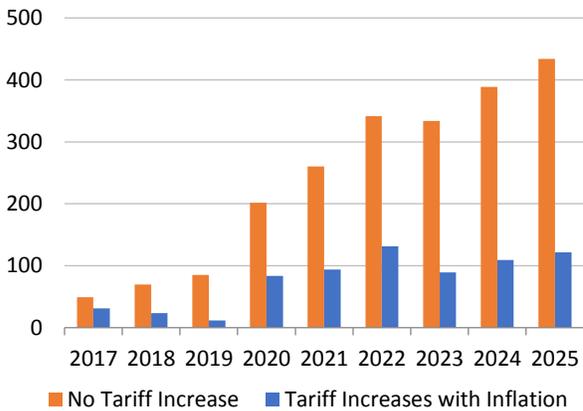


Figure 11: Projected Deficit (Tk Billion)



25. **To cover the deficit, tariff increases will have to exceed inflation going forward (Figure 13).** A tariff increase of 15% per year will be required to reach cost recovery tariff (i.e. tariff sufficient to cover costs and therefore no budget transfer requirement) by 2020. If tariff increases annually by 9%, cost

recovery will be achieved in 4 years (2018) (tariff will continue to be increased with inflation beyond 2018 to remain at cost recovery). On the other hand, if tariff increased by 8% on average per annum, a breakeven could be achieved in 6 years. The increase in tariff will have to exceed the rate of inflation which is expected to grow by 6% per annum to cover the cost of generation and distribution. If tariffs were to increase only with inflation, the subsidy provided for power supply would increase to Tk121 billion by 2025.

Figure 12 Average Cost and Selected Tariff Options (Tk/kWh)

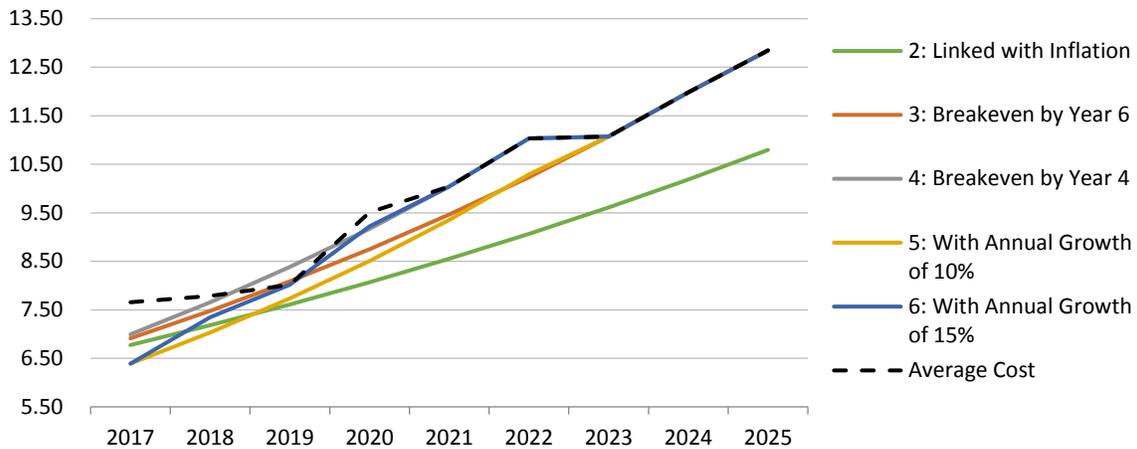
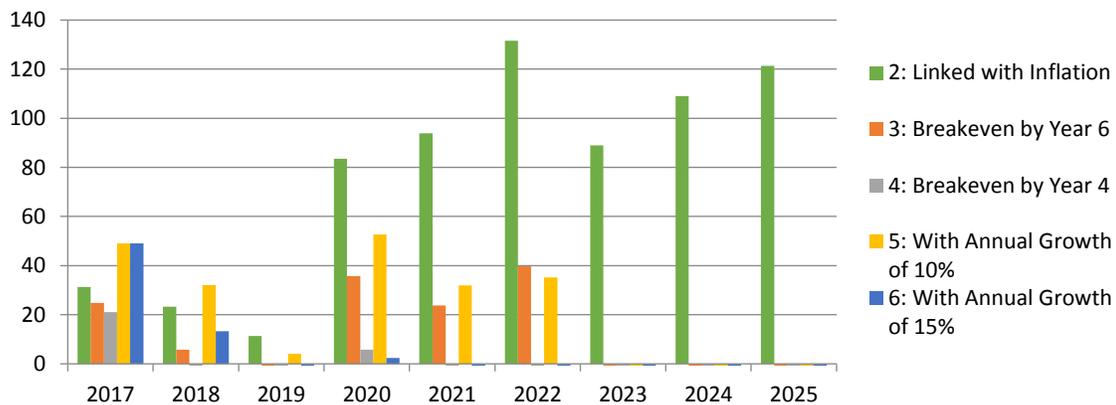


Figure 13: Deficit under Tariff Scenarios (Tk Billion)



Gas Price Assumptions

26. **As gas prices for the power sector remain unsustainably low, the model's baseline assumption of the current gas price increasing only with inflation over time is in contrast to sound economic principles for pricing.** Gas pricing should take into account the opportunity cost of gas use. Despite the low cost of onshore gas, the gas pricing policy fosters an environment of waste and inefficient consumption, which is unsustainable in the long run. It should also be noted that domestic gas production will peak in 2018 and decline thereafter as the Bibiyana field, which accounts for nearly 40% of gas supply, is nearing depletion. The shortage in gas supply requires that GOB allocate the scarce gas resource through

a policy intervention. Today, gas use by the fertilizer sector is rationed during the summer months when electricity demand is higher. This policy intervention will be further tested when domestic supply begins to decline.

27. **LNG imports will substantially increase the average cost of gas supplied to the power sector since LNG will replace cheap domestic gas in existing gas fired plants.** Currently, the power sector pays US\$1.05/mcf for natural gas supplied. This figure will have to increase in the future when LNG becomes part of the supply mix. LNG landed prices average US\$6-7/mcf into India, which reflects the costs Bangladesh should expect. The model assumes that domestic gas supplied to the power sector will peak at 910mmcf/d in 2018 and then decline at a rate of 5% per annum. LNG imports are expected to begin in 2018 with 500mmcf daily imports on average. The reliance on LNG imports for power generation is expected to decline when the proposed coal fired plants come online in 2020. Thereafter, LNG imports will have to gradually replace domestic supply. This analysis has relied on LNG price forecasts by the World Bank, which projects that LNG prices will rise to US\$14/mcf by 2025. As result of rising LNG prices and increasing share of gas imports in domestic supply, the weighted average cost of gas will rise to US\$8.8/mcf in 2025 from the current US\$1.05/mcf.

Figure 14: Gas Production Forecast in Bangladesh (mmcf/d)

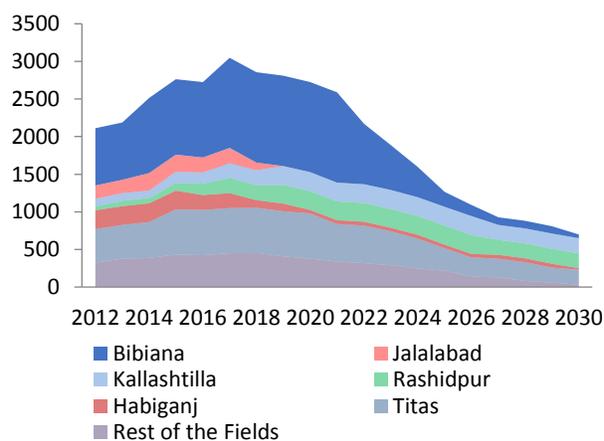
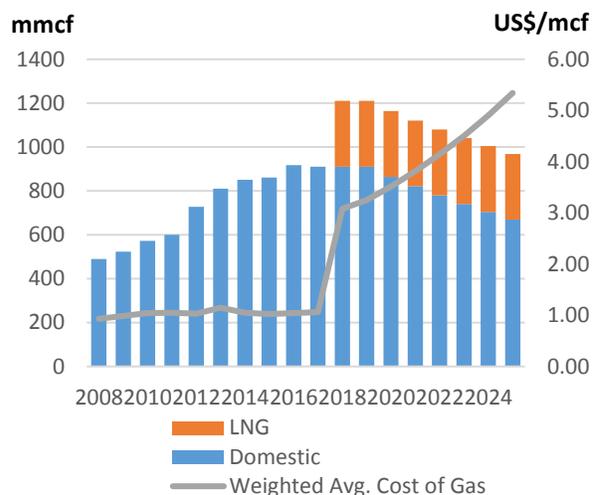


Figure 15: Gas Supply and Cost of Supply Projections



Source:

Scenario Analysis

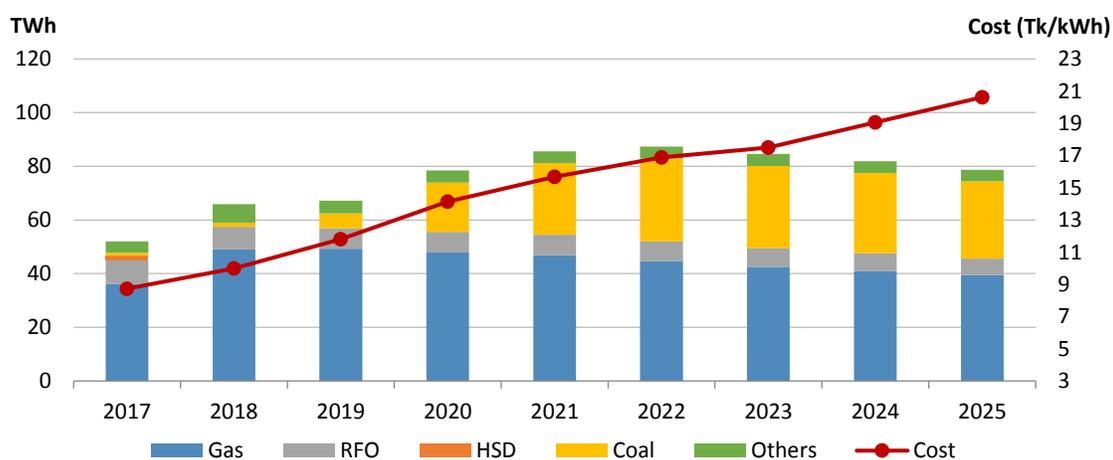
28. **The financial model is now used to project the evolution of power generation costs under various generation expansion, tariff and other scenarios to come up with the sector financial deficit and need for state support or changes to tariffs, etc.** This permits identification of appropriate actions for BPDB, including limiting the addition of high cost generation and/or applying to the regulator for tariff changes, etc.

29. **The model was used to analyze the following scenarios:** (i) Import of LNG – resulting in a weighted average price of gas that gradually approaches the international price; (ii) Pricing domestic gas at its economic cost (i.e., equal to the price of imported LNG); (iii) Delay of 3 years (to 2021) in LNG imports

materializing; (iv) Delay in coal coming online by 5 years (i.e., instead of 2020, coal becomes 20% of the generation mix in 2025); (v) Implementing a carbon tax on power generation.

30. **Sector deficit will be much higher in the event domestic natural gas prices were to increase to match alternative fuel prices.** An increase in gas prices remains inevitable as Bangladesh is looking to import LNG at higher costs. Gas is also severely underpriced compared to alternative fuels. Users of gas for transport (through compressed natural gas, CNG) already pay US\$13/mmbtu for gas use (which is still below the price of diesel). If the natural gas price domestically was to rise gradually to match the price of fuel oil (on energy equivalent basis) by 2022, the cost of power supply will rise above Tk16.88/kWh (figure 16) resulting in an annual deficit of Tk 823.9 billion by 2022 in case of no tariff adjustments. Correspondingly, power tariffs would have to rise by 16% per annum at a minimum to keep pace with the cost of gas supplied.

Figure 16: Generation and costs assuming that gas prices rise to equal fuel oil prices by 2022



31. **Further delays in planned coal generation will severely limit grid supply of electricity and force an increase in oil based generation.** The Power System Master Plan called for a significant rise in coal-based generation to address the strong growth in power demand and the expected drop in domestic gas supply. Coal generation capacity will need to grow from 200MW in 2015 to 9GW in 2025 and 15GW by 2030 according to the Master Plan. The ambitious plan has been adopted by GOB, yet implementing the plan to increase coal generation significantly continues to face several hurdles. Coal plants require substantial capital investment. Bangladesh is also considering importing coal though it lacks the port infrastructure to do so. Domestic coal production remains limited to supplying coal to the Barakapuria plant and an increase in coal production has thus far remained difficult to achieve. As a result, none of the mega coal projects, foreseen by the Master Plan, has made significant progress towards implementation. Yet, power generation capacity based on imported coal is projected to reach 2.9GW by FY2020 and 5.2GW by FY2025 based on plans for several new large-scale coal fired plants. If the planned projects get delayed by another two years, a generation surplus of 25% would turn into a deficit of 11%. If the delay in coal generation would be addressed through LNG imported for rental plants the average cost of unit sold would rise from 12.51Tk/kWh to 13.06Tk/kWh in FY2025.

32. **Delays in LNG will also increase the cost of generation as a result of the continued use of liquid fuel.** According to GOB plans, the LNG import facility will open in the latter part of 2017 or in FY2018. The first LNG terminal (floating) is planned to start in 2018 supplying about 300mmcf/d of gas for power generation. Given that the implementation of the terminal has been delayed by several years and the planned 90km gas pipeline to the main network has yet to be constructed, there is a likelihood that LNG imports will be further postponed. A one-year delay in LNG imports to 2019 would create a projected power shortage of 9% of total available generation. With 300mmcf/d of gas an additional 12,000GWh of electricity will be generated to the projected 37,000GWh in 2018. If LNG imports get delayed, then a portion of the 12,000GWh will have to be replaced with fuel oil based power. The average cost of power sold would increase from 7.67Tk/kWh to 8.34Tk/kWh.

33. **Implementing a carbon tax on power generation will undoubtedly increase breakeven tariff rates.** Incorporating the current social cost of carbon of US\$30/tCO₂ (increased to US\$42.5/tCO₂ by 2025 as per World Bank estimates), the break-even tariff needs to be increased by Tk1.47/kWh in 2017 to Tk3.23/kWh by 2025.

Figure 18: World Bank on the Social Cost of Carbon (US\$/tCO₂)

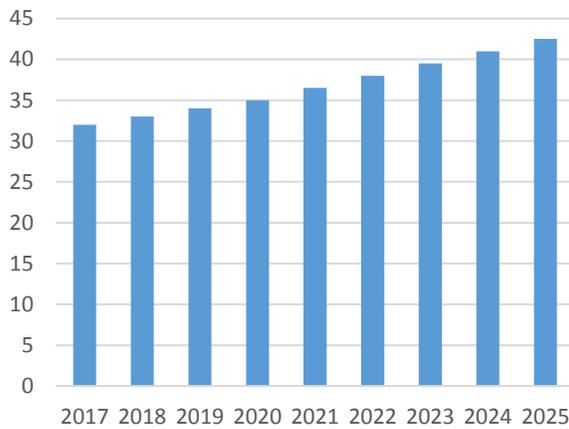
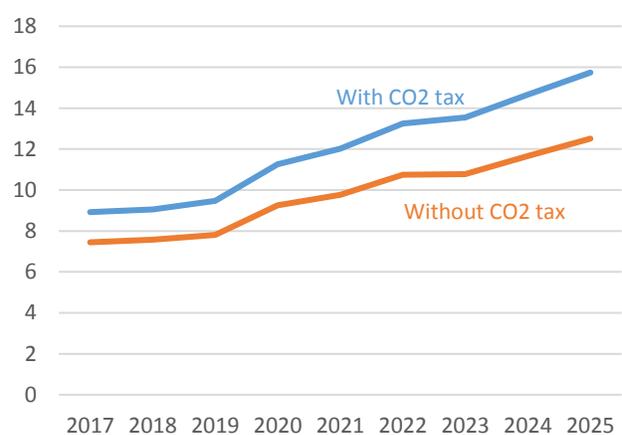


Figure 19: Average Cost of Power with CO₂ Tax (Tk/kWh)



34. The Table below summarizes the results of the scenarios analyzed in this paper. As can be seen ...

Table XX.

Scenario	Cost of Power Generation	Break-even Tariff	Time to break-even
LNG imports delayed			

Conclusion

35. **It appears from this analysis that the power generation expansion plan of BPDB may be overly ambitious in terms of the timing of availability of low-cost power from large base-load plants.** Thus, the base-case scenario may be underestimating the role of liquid fuel-run plants and the resulting cost of power generation. The generation expansion plan of the BPDB assumes that share of coal in generation will rise from the current 2% to 20% by 2020 and 40% by 2025. Coal-based power projects are currently significantly delayed. Similarly, a number of large gas-based power plants are also delayed. As a result, the model likely underestimates the future importance of liquid fuels for power supply. Power from rental plants can be provided with minimum planning and the supply of fuels can be managed through the existing distribution network. On the other hand, the supply of additional coal and gas will require further investment in import capacity and/or additional infrastructure in extraction. The power sector will have to import more LNG than planned or rely more heavily on fuel oil in the future if investments in additional domestic gas and coal supply and capacity do not materialize as planned.

36. The sensitivity analyses presented in this note show the impact on generation costs from increased use of liquid fuel for meeting the demand-supply gap occasioned by likely delays in commissioning large base load power plants. With the decrease in availability of low-cost domestic gas for power, costs of power generation is expected to increase in every possible fuel mix scenario. Tariff adjustments will need to be continued so as to avoid the sector financial deficit growing beyond the ability of GOB to absorb. Increasing import of electricity initially from India and later tapping into the hydropower resources of Nepal and Bhutan could help Bangladesh reduce its dependence on high cost liquid fuel plants.