Financial Implications of Emission Standards for Coal Power Plants

Introduction

In December 2015, the Ministry of Environment, Forest and Climate Change (MoEFCC) notified new emission standards for coal thermal power plants (TPPs). The new standards mandate reduction of sulphur oxide (SO_x), nitrogen oxide (NO_x), and mercury (Hg) emissions, along with tightening of the existing norms for particulate matter (PM_{10}) emissions. Around 50% of the total SO_x, 30% of total NO_x, and 8% of total $PM_{2.5}$ emissions are attributed to the energy sector, within which coal TPPs are the biggest contributors (IEA and IIASA, 2015). Once MoEFCC's standards are implemented, the air quality in India could significantly improve. Standards have been specified differently for unit, vintage and installed capacity. The original deadline for compliance was December 2017. Due to limited progress in implementing the standards, MoEFCC recently decided to support the Ministry of Power's (MoP's) phasing plan, which extends the deadline for implementation to 2022.

Highlights

- **To comply with the new emission standards, most coal TPPs will have to incur INR 0.5–1 crore/MW.**
- **For control measures applicable in different vintage and capacities of power plant units, total investment till 2030 will be around INR 3,96,200 crore. Over 60% of this accounts for upfront costs.**
- **The generation tariff will increase by INR 0.25–0.75/kWh (21–25%).**
- **To facilitate implementation of the emission standards, the government should also consider:**
  - **(a) Providing grants to existing plants whose upfront costs will be more than INR 1 cr/MW; most plants in this category are privately owned.**
  - **(b) Developing detailed regulatory guidelines to enable tariff transfer to consumers.**
  - **(c) Developing synthetic gypsum market to monetise the by-product from FGD technologies, as additional revenue for new plants.**

The Center for Study of Science, Technology and Policy (CSTEP) modelled the current emission concentrations in the flue stacks of different plants based on unit capacities, vintage and their coal linkages. Coal from Indian mines have high ash content (which contributes to PM emissions), while imported coal from South Africa and Indonesia have high sulphur content. Assuming average plant operating conditions and combustion conversion factors from literature, CSTEP's analysis indicates that in order to meet the standards, concentrations of SO_x need to be reduced by 67–95%, NO_x by 41–95% and PM_{10} by 50–85%[1]. CSTEP evaluated the health implications of complying with the new standards. Over 3.2 lakh premature loss of lives, 5.2 crore (52 million) Respiratory Hospital Admissions (RHA), and 126 million Work Loss Days (WLD) can be avoided till 2030, if the standards are met by 2025 (Srinivasan, et al., 2018).

Figure 1, Figure 2 and Figure 3 illustrate the range of likely emission concentrations for a typical Indian TPP, and the targeted emission standard specified for TPPs of various vintage and unit

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[1] In the previous emission standards, there were no emission limits for SO_x and NO_x.
PM: Unit capacity lesser than 210 MW = 350 mg/Nm^3; greater than or equal to 210 MW = 150 mg/Nm^3
Electro-Static Precipitators (ESPs) were installed in plants to meet emission standards.
To limit impacts of flue gas emissions on ambient concentrations, stack height was also specified by MoEFCC for various unit capacities, i.e., greater stack heights for higher flue volume from larger units. Further, stack height should be at least 275 metres if the power generating unit is within city limits.

capacity. The range of emissions will depend on the coal composition and existing pollution controls, if any.

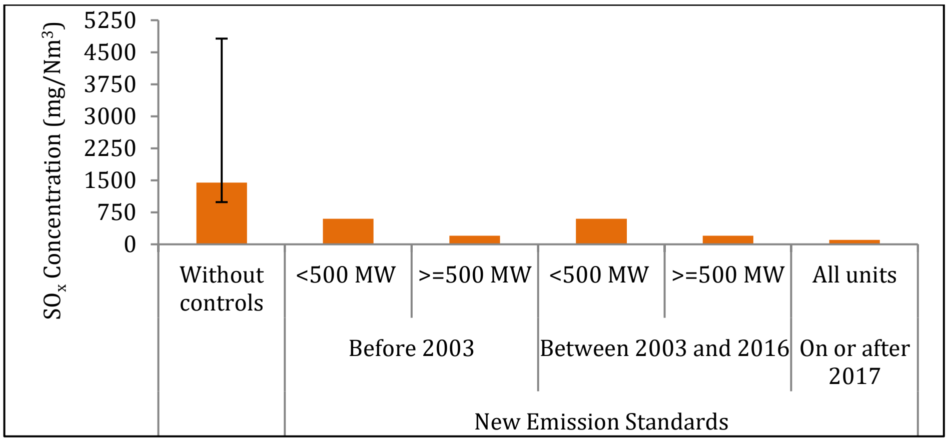

Figure 1: Current concentrations and targeted concentration of SO_x in flue gas[2]

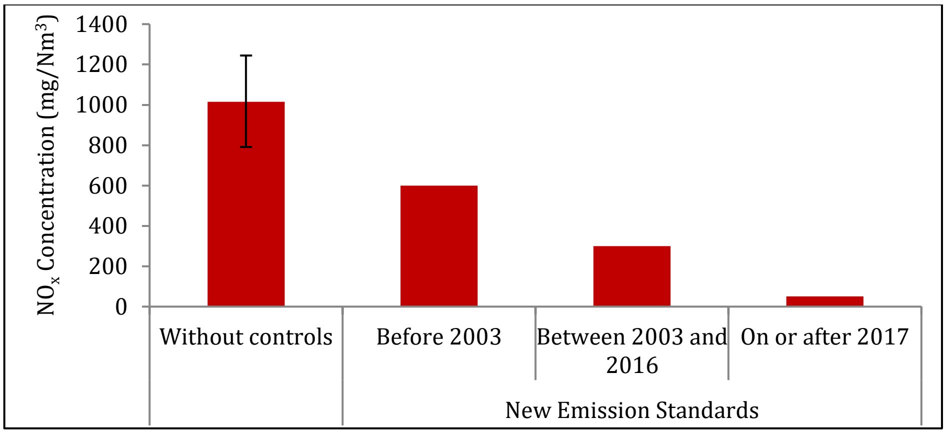

Figure 2: Current concentrations and targeted concentration of NO_x in flue gas

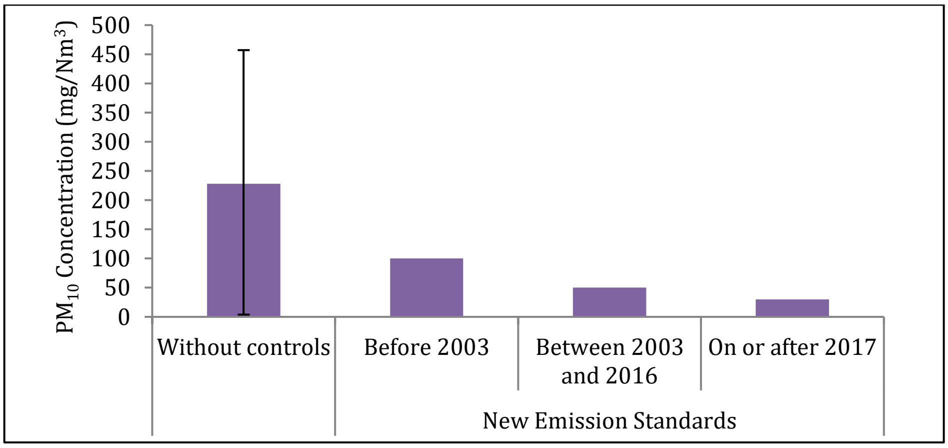

Figure 3: Current concentrations and targeted concentration of PM_{10} in flue gas

[2] The concentration of SO_x in flue gas for a lignite plant (7362 mg/Nm^3) is not shown in the figure, even though it has the highest sulphur content, because the share of plants linked to lignite is very less (only 6.3 GW out of 263 GW in 2030).

The bar graphs of current concentrations shown in Figures 1–3 were estimated considering South Eastern Coal Field Limited (SECL)[3] type as the coal fed into the boiler. The higher values of current SO_x and NO_x concentration (error bars) represent emissions from plants that consume coal with the highest sulphur and nitrogen content [Indonesian coal and Eastern Coal Field Limited (ECL), respectively]. There is a higher emission removal requirement for SO_x and NO_x across plant vintage and capacity categories. This implies that controls with higher removal efficiency will need to be installed.

For modelling current PM_{10} emissions, we factored in a removal efficiency of 95% in older units and 98.5% for more recently commissioned units, which adhered to earlier PM emission standards. The higher band of PM_{10} concentration represents the values in older plants with coal linkage to Mahanadi Coal Field Limited (MCL) (highest ash content). These plants will either need to upgrade or retrofit controls for higher performance Electro-Static Precipitators (ESPs) in order to meet the new standards. Conversely, the lower band of concentration represents imported coal with lower ash content. These units will also need to install High Performance ESPs to meet the revised standards, as current ESPs will prove to be inadequate.

Current emissions of Hg (average of 0.012 mg/Nm^3) are lower than the new emission standards (0.03 mg/Nm^3). Further, since a considerable amount of Hg is retained in fly ash, and captured by ESPs, no further controls will be needed (Das, Choudhury, & Senapati, 2015).

Table 1 provides the details of the technologies available in India and their costs, with pollution removal efficiencies (USEPA, 2002; CSE, 2016; GE Power, 2016).

Table 1: Pollution control technologies available for coal TPPs

Pollutants	Pollution Control Technologies	Capital cost (INR lakh /MW)	Removal efficiency (%)	Remarks
SO_x	Wet Flue Gas Desulphuriser (WFGD)	50	95	Limestone is used as a reagent and gypsum is the by-product.
	Sea Water FGD	30	92	Seawater is used. Reagent is no required.
	Dry FGD	35	92–98	For a unit of capacity <=400 MW
	Limestone Injection	15	57	Limestone is used as a reagent.
	LI and washed coal[4]	15	69	Washed coal is used in the boiler.
NO_x	Selective Catalytic Reduction	30	90	Urea or ammonia are used as reagents with catalyst.
	Selective Non-Catalytic Reduction	20	57.5	Urea or ammonia are used as reagents.
	Low NO_x Burner (LNB)	5	50	Installed in boiler
	LNB and Over Fire Air	8	53	Installed in boiler
PM	Upgradation of Electrostatic Precipitator (ESP)	5	99.6	Upgradation of collection and discharging electrodes and addition of filter arrays to improve removal efficiency.
	High Performance ESP and washed coal	10	99.8	

[3] Based on the review of literature, nine domestic coal types and three imported coal types are mainly used in Indian TPPs. The South Eastern Coal field limited (SECL) supplies around 20% of the total coal consumed by coal TPPs (Ministry of Coal, 2016).
[4] Usage of washed coal instead of raw coal can also reduce mercury emissions further by 13–39% (UNEP, 2014).

All proposed units and some of the existing units (above 500 MW), commissioned during 2003 and 2016, will need to invest in high performing Pollution Control Technologies (PCTs). This implies a capital investment of up to INR 90 lakh/MW[5]. The available high performing PCTs are FGD for SO_x, SCR and SNCR for NO_x and High Performance ESPs for PM. Plants situated in coastal areas can opt for the cheaper SWFGD, instead of fresh water FGD. The smaller sized units, commissioned during 2003 and 2016, can also opt for lesser capital intensive PCTs that offer lower removal efficiency, such as LI for SO_x reduction due to relatively lower standards (refer Figure 1 and Table 1). The required investment for these units is around INR 50 lakh /MW. The investments for old plants (before 2003) will be lower as they will be able to meet the standards with LI, LNB, OFA and upgraded ESPs (INR 13 lakh/MW).

These investments suggest that PCT installation costs can range from 7–20% of the current capital investment required for a TPP[6]. This will have commensurate implications on the cost of electricity. As of now, there is limited clarity on the modalities of implementation of the standards, and how power producers will be able to recover investment costs. However, since the planned deadline for compliance is within 5 years, CSTEP conducted a detailed analysis of the financial implications for a diverse set of plants, based on capacity and vintage considerations mentioned in the emission standards.

Cases for Estimating Impact on Tariff

We analysed the impact on tariff by developing representative TPP units denoting different emission standards. Based on the new emission standard classification, the existing and proposed TPP units were classified into the three categories, namely plants commissioned: (1) before 2003; (2) in 2003–2016; and (3) in 2017–2030. Further, this was sub-classified based on the unit's capacity, i.e., less than 500 MW and more than or equal to 500 MW.

Table 2: Profile of existing and proposed coal TPP units (vintage and capacity)

Commissioning year	Unit capacity	Installed capacity (GW)	Percentage share of installed capacity as on 2030
Before 2003	<500 MW	46	16.4%
	>=500 MW	12	4.6%
Between 2003 and 2016	<500 MW	37	13.6%
	>=500 MW	93	30.8%
After 2016	<500 MW	7	3.6%
	>=500 MW	68	31.1%

Table 3: Number of units commissioned in different vintage capacity

Number of units	<1992	1992-2002	2003-2016	>2016
60 MW	19	1	7	2
110 MW	26	1	3	0
210/250 MW	78	62	60	2
550 MW	12	8	59	8
600 MW	0	0	42	14
660 MW	0	0	42	84

As seen in Table 2, a majority of the TPP units commissioned before 2003 were less than 500 MW; larger capacity units have been installed since 2003. Around 72% of the existing installed

[5] The upfront cost for PCT installation is higher by around 5% if one considers interest during construction and associated labour costs.
[6] Capital investment for a new coal TPP is around INR 5–7 crore/MW.

capacities are of the 2003–16 vintage. For the proposed plants (to be commissioned after 2016), nearly 80% of all units in the pipeline have unit capacity of 600 or 660 MW (Table 3) (CEA, 2013) (CEA, 2016) (Center for Media and Democracy, 2017). While TPPs installed before 1992 account for around 37 GW (or 135 units), they were omitted from the current financial analysis as they are nearing the end of their life.

Based on the above-mentioned analysis on plant data, representative cases were considered to indicate emission standard categories (Table 4)[7]. The cases represent 84% of the total capacity likely to be installed in 2030 (263 GW).

Table 4: Cases for financial assessment of PCT costs

Cases	**Description**	**Representative of installed capacity**	**Pollution control technologies implemented (Removal efficiency)**	**Remaining plant life as on 2018 (years)**
Case 1	210 MW subcritical unit commissioned in 2002	~ 20 GW	LNB and OFA (52.5% for NO_x), washed coal (30% for PM and 25% for SO_2), LI (55% for SO_2)	9
Case 2a	210 MW subcritical unit commissioned in 2011	~ 135 GW	Up gradation of ESP (99.4% for PM), LI (55% for SO_2), SCR (90% for NO_x)	18
Case 2b	500MW supercritical unit commissioned in 2011		Up gradation of ESP(99.4% for PM), WFGD (95% for SO_2), SCR (90% for NO_x)	18
Case 3	660 MW supercritical unit commissioned in 2017	~ 68 GW	ESP (99.6% for PM), WFGD (95% for SO_2), SCR (90% for NO_x)	24

The total capital investment to be made for PCTs in TPPs operational between 2015 and 2030 was estimated to be around INR 2,50,000 crore by CSTEP.

In this analysis, CSTEP used the Central Electricity Regulatory Commission's (CERC's) guidelines (CERC, 2014) to estimate the levelised tariff of TPPs. This was a proxy for estimating the baseline levelised cost of electricity generation, as production cost details can vary by TPP. Also, the data on tariff for all TPPs are not available in the public domain. The financial parameters specified in the CERC's guidelines, and actual plant operating parameters reported by the Central Electricity Authority (CEA), were used for the analysis. A Plant Load Factor (PLF) of 85% is considered for the tariff calculation.

Financial Parameters

Table 5 provides the other input costs required for variable cost estimation with PCTs. The operational and maintenance (O&M) cost for PCTs ranges between INR 0.04 (for NO_x control) and INR 0.15/kWh (for SO_x control) (MIT, 2007) (Sargent & Lundy, 2013). In this analysis, we have not considered the escalation rate for cost of coal, reagents, and O&M expenses for PCTs.

[7] Details of the development of cases for the financial analysis are provided in the technical report published by CSTEP, titled 'Benefit Cost Analysis of Emission Standards for Coal-based Thermal Power Plants in India'.

Table 5: Input costs used for variable cost estimation of PCTs

Reagent	Cost (INR/tonne)
Coal	2230
Low quality limestone	2900
Urea	12,000
High quality limestone[8]	3500
Gypsum (by-product from FGD)	1200
Cost for washing coal	490

	INR/kWh
Cost of waste disposal from FGD	0.092
Cost of catalysts for SCR	0.024

Results and Discussion

We estimated the generation tariffs for four representative cases, with and without the implementation of new standards (Table 6). Among the different cases considered in the analysis, the increase in tariff is the highest for Case 2 plants.

Table 6: Cost implications of PCT implementation in coal power plants

Cases	Current generation cost (INR/kWh)	Generation cost with PCT (INR/kWh)	Increase (INR/kWh)	Percentage increase (%)
Case 1	2.81	3.08	*0.28*	*9%*
Case 2a	3.23	3.90	*0.67*	*21%*
Case 2b	2.92	3.65	*0.73*	*25%*
Case 3	3.27	3.91	*0.63*	*19%*

The higher capital investments for SO_x and NO_x controls, as well as additional reagent costs, increase the overall costs for implementing the standards. Further, since lesser time is available for this vintage of plants to recover investments, tariff is higher (increase of 20% to 25%) in this category, as compared to Case 3 plants. In Case 1 plants, we anticipate an increase of around 9% (0.28 INR/kWh). The tariff increase in this case is significant despite less costly PCTs due to a lower recovery time. Also, it is important to note that in plants that need to install WFGDs (Case 2b and Case 3), a considerable reduction in the additional cost incurred is possible with the development of synthetic gypsum—a by-product from WFGD. The FGD gypsum can be used in cement production, road construction and in agriculture sectors to improve soil properties. The tariff in this case can be limited to INR 3.82/kWh (~17%).

[8] Limestone of high quality ($CaCO_3 \geq 80\%$) is required to generate saleable by-product.

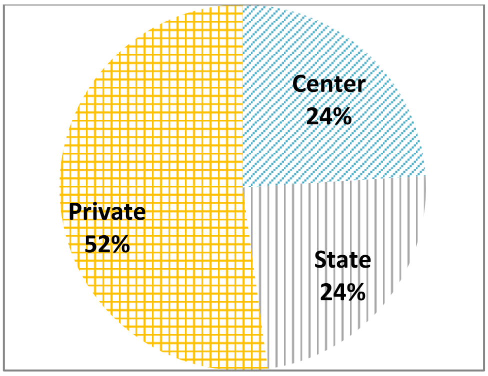

Figure 4: Percentage share of ownership of plants in 2003–16 vintage

Around 129 GW (50% of the total installed capacity operating in 2015–30) comes under Case 2 category. Of which 52% is privately owned (Figure 4). The state and centrally owned plants may find it easier to meet upfront costs of PCTs via budgetary allocations. However, individual power producers in the private sector will find it challenging to finance the large amount of PCT investment required.

Impact of Plant Load Factor (PLF) on Tariff

The impact of PCT installation on generation tariffs for plants operating at lower PLFs is significant. CSTEP estimated that the base tariff (without PCTs) for plants operating at lower PLF (50%) is possibly already much higher—by INR 0.7/kWh (Case 1) and INR 0.97/kWh (Case 2b). This implies that these power producers are already facing a 27–33% increase in generation costs already. The major reason for lower PLFs in TPPs is the lack of continuous coal supply, increased maintenance time in older TPPs, and issues of surplus power in the grid (Mukherjee & Tripathy, 2017) (Equitymaster, 2018). Over 50 TPPs based on coal or gas are operating at lower PLFs (30–50%) (Mukherjee & Tripathy, 2017).

With the introduction of PCTs in these plants, the difference in tariff will be compounded, and will be as high as INR 1/kWh (Case 1) to INR 2/kWh (Case 2b). Therefore, installation of PCTs in plants operating at lower PLFs will put these plants under more financial stress. Hence, in plants of relatively newer vintage, PCT installations will be financially viable only if measures to improve PLF are undertaken. For older plants operating at the bare minimum technical PLF, policy guidelines that mandate shutdown plans, especially in winter months when emissions may not disperse, would be economically more feasible than installing PCTs. Seasonal shutdown plans have also been deployed in China (Lelyveld, 2017). Similar allowances have also been considered in the European Union (Wynn & Coghe, 2017). These guidelines can serve as a template for the Indian context.

Summary and Policy Recommendations

Possible policy interventions, to manage the likely tariff increase and financing options for managing high upfront costs, are provided below:

1. Pass tariff onto consumers
   The Electricity Act provides recourse to power producers in cases where tariff revisions are necessitated by a change in law, such as the new emission standards. Based on the financial case analysed (including capital and variable costs), we propose the following options to pass the tariff onto consumers:
   a. State Electricity Regulatory Commissions (SERC) and CERC include an allowance in the new tariff guidelines (2019–24) for plants commissioned between 2003 and 2016 to avail a tariff hike of up to INR 1/kWh for 5 years, or up to INR 0.7/kWh for 10 years.
   b. SERCs and CERCs include an allowance provision of up to INR 8.5 lakh/MW per annum, for 5 years, for older units (Case 1) to recover their PCT investment. This would be similar to the annual allowance provision in older guidelines given for old plants for cost recovery of life extension activities (INR 7.5 lakh/MW per annum) (CERC, 2014).
2. Provide one year grant window or subsidy scheme
   Since upfront costs will likely be a barrier in implementing standards in a time bound manner, the government can consider an enabling grant corpus or a subsidy scheme. Providing a one year window for a grant of INR 93,500 crore can support the PCT capital investment needed in plants commissioned between 2003 and 2016 (or 37% of the total capital investment). Plants that avail the grant for meeting capital costs can seek tariff revisions based on allowance of up to INR 18 lakh/MW per annum for variable or operating costs of PCT (limiting the end tariff increase to 14%).

3. Enable additional revenue for new plants
   Newer plants will have to compete in the electricity market with higher tariffs. A loan interest waiver or lower interest rate for PCTs to incentivise quicker uptake can have only a marginal effect on limiting tariff increase. However, the development of a synthetic gypsum (a by-product from FGD) market in India can provide additional revenue for new plants. Synthetic gypsum can be used as a raw material in cement and glass manufacturing industries, or as a construction material. This could limit the increase in tariff to 17% (approx. INR 0.5/kWh increase in tariff).

Finally, the government needs to address other concerns such as lack of domestic PCT manufacturing capacity, limited technology providers in India and the delays in procurement and installation of PCTs (up to 2 years). One possible solution could be the removal of tax levies for imported PCT equipment during a five-year window. Further since this is an industry-wide mandate, shutdown time for installation of PCTs in several plants and PCT procurement plans, need to be evaluated and scheduled from a grid-stability perspective.

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