New environmental norms and Technologies : Coal based power sector

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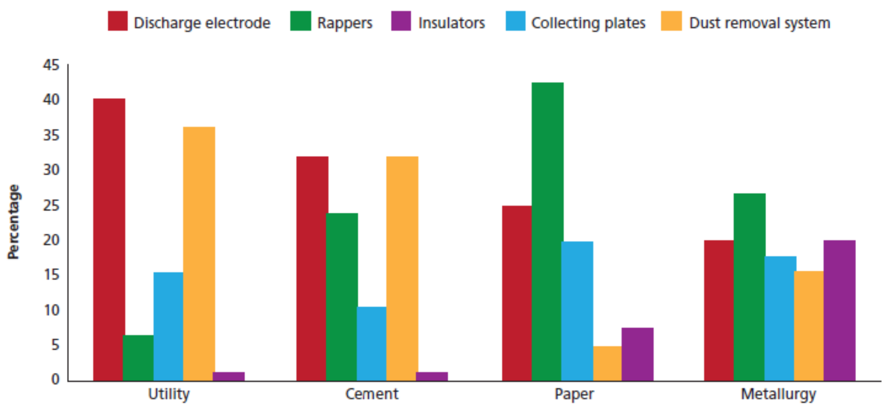
Journey So far---
Particulate matter: Control

PROBLEM AREAS IN ESPs



- All installations generally designed to meet new norms
- Reasons for failures:
  1. Dust removal systems: hopper level switches are bypassed deliberately to avoid labour costs. Mismatch of flyash evacuation system and ESP ash dislodging capacity.
  2. Discharge electrodes:
     – operated at an inappropriate voltage, suffer mechanical damage

Upgrading ESPs: Methods

Control

- Improved diagnostics of operating behavior and faults
- Micro-processor-based intermittent charging controllers

Process

- Flue gas conditioning

Electrical

- Increased rating of TR sets
- Increased high-tension sectionalization

Mechanical

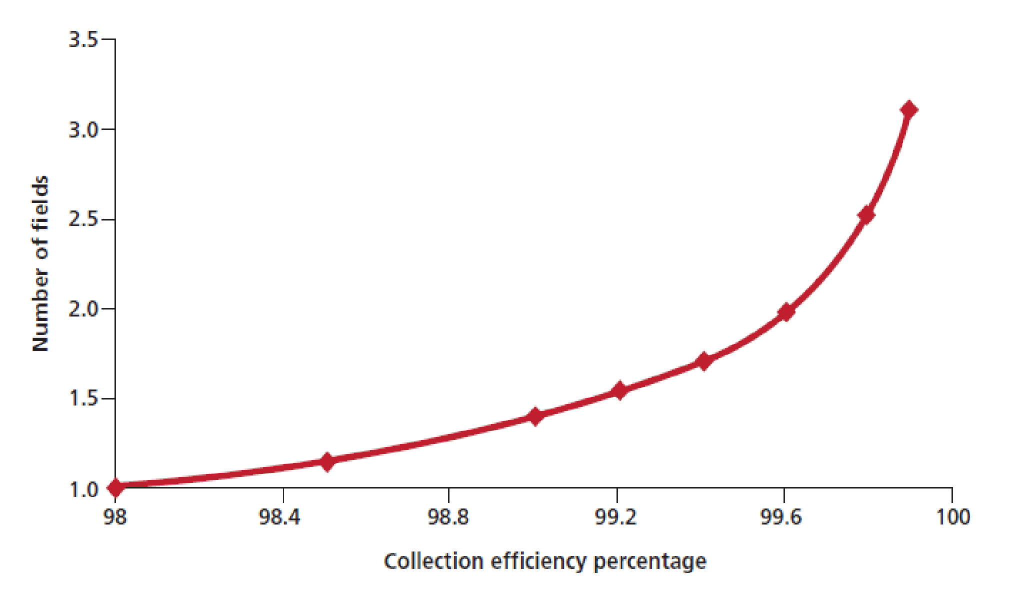
- Augumenting collection area
- Electrode strength and alignment

Refurbishment techniques: Preferred solutions

1. Adding fields in series to an existing ESP
2. Placing additional ESPs parallel to an existing ESP
3. Adding new internals by increasing the casing height
4. Replacing old ESPs with new ones
5. Filling the dummy fields of ESPs

SIZE OF ESP VS COLLECTION EFFICIENCY

To improve collection efficiency from 99.2 to 99.8 per cent, the size of ESPs needs to be doubled



Refurbishment techniques: Minor improvements

- Optimizing power supply
- Introducing more bus bars and transformer rectifier sets
- Flue gas conditioning (FGC)
- Introducing a bag filter in an existing ESP's casings, changing electrodes etc

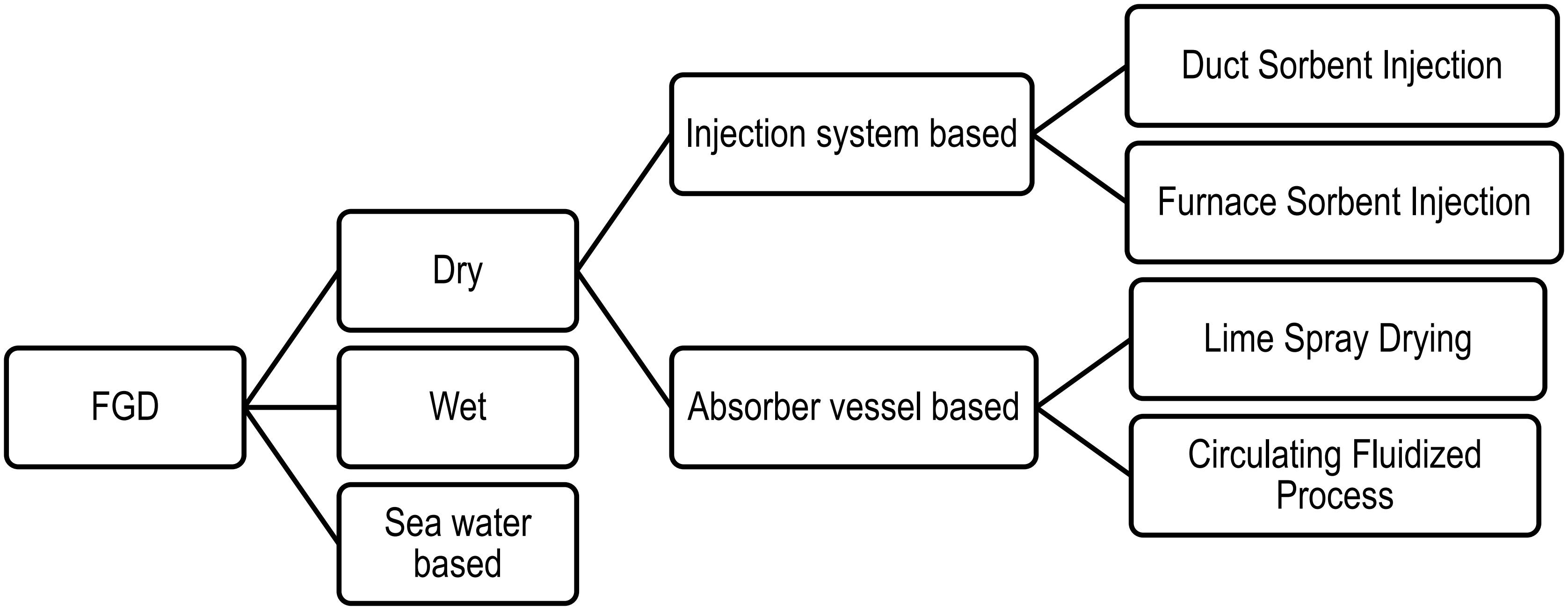
Sulphur di oxide: Control

- SO_2 emissions can be controlled by three methods:
  - Before combustion, by lowering sulphur content in the fuel.
  - During combustion, by injecting sorbents such as limestone.
  - After combustion, by treating flue gas with sorbents in FGD devices or in ducts.

Emissions Range

Sulphure in Coal	SO_2 emission	
	Indian Coal	Imported Coal
NCV (Kcal/kg)	4100	5500
Wt%	mg/Nm^3	mg/Nm^3
0.1	258	190
0.2	516	380
0.3	775	570
0.4	1033	760
0.5	1291	950
0.6	1549	1140
0.7	1808	1330
0.8	2066	1520
0.9	2324	1710
1.0	2582	1900
1.2	3099	2280
1.4	3615	2660
1.6	4132	3040
1.8	4648	3420
2.0	5165	3800
2.2	5681	4180
2.4	6198	4559
2.6	6714	4939
2.8	7231	5319
3.0	7747	5699

Sulphur di oxide: Control



Sulphur di oxide: Control

	WET FGD	Dry FGD
Commercially available range	~ 1,100 MW	300–400 MW single absorber For novel integrated desulphurization (NID) each module of 75 MWe
Types	1) Seawater 2) Freshwater	1) Spray dry absorber (SDA) 2) Circulating dry absorber 3) NID.
SO2 removal efficiency	Upto 99 per cent	Upto 99 per cent (90–95 per cent for SDA)
Sorbent use	Approximately 1.5–2 tonne limestone consumed per tonne SO2 removal	Approximately 0.75–1.5 tonne lime consumed per tonne SO2 removal
Water consumption in m^3/ MWh	0.2–0.25 m^3/ MWh for power plants between 200–500 MW;	0.1–0.2 m^3/ MWh for power plants up to 200 MW. The semi dry system is not recommended for power plants > 200 MW
Auxiliary power con-sumption	Freshwater FGD: 0.7 per cent Seawater FGD: 0.7–1.5 per cent	1–2 per cent
Condition of existing stack	Existing stacks to be modified in all cases	Existing stacks can be used without modification
FGD by-product	Freshwater FGD: gypsum Seawater FGD: no by-product	$CaSO_3$/ $CaSO_4$: Has to be land filled

FGD: space and Installation time

	1*150 MW[1]	4*150 MW[+]	2*660 MW[+]	5*800 MW[+]
Area required for the wet FGD system in acres	0.6	2.2	2	7.6

[1]Dedicated Limestone Slurry Preparation and Dewatering system
[+] FGDs have common Limestone Slurry Preparation and Dewatering system
Source: Thermax, 2016

- The construction of an FGD unit involves both civil and mechanical work— installation of scrubbers, gas re-heaters, ducting and chimney lining, or the construction of a new chimney.

- Typically, construction requires about 18 months for a 500 MW unit. The shutdown time to hook up a wet FGD system to the unit takes upto one month, depending on the chimney construction.

Oxides of nitrogen: Control

NO_x abatement

Burner modification

Flue gas treatment

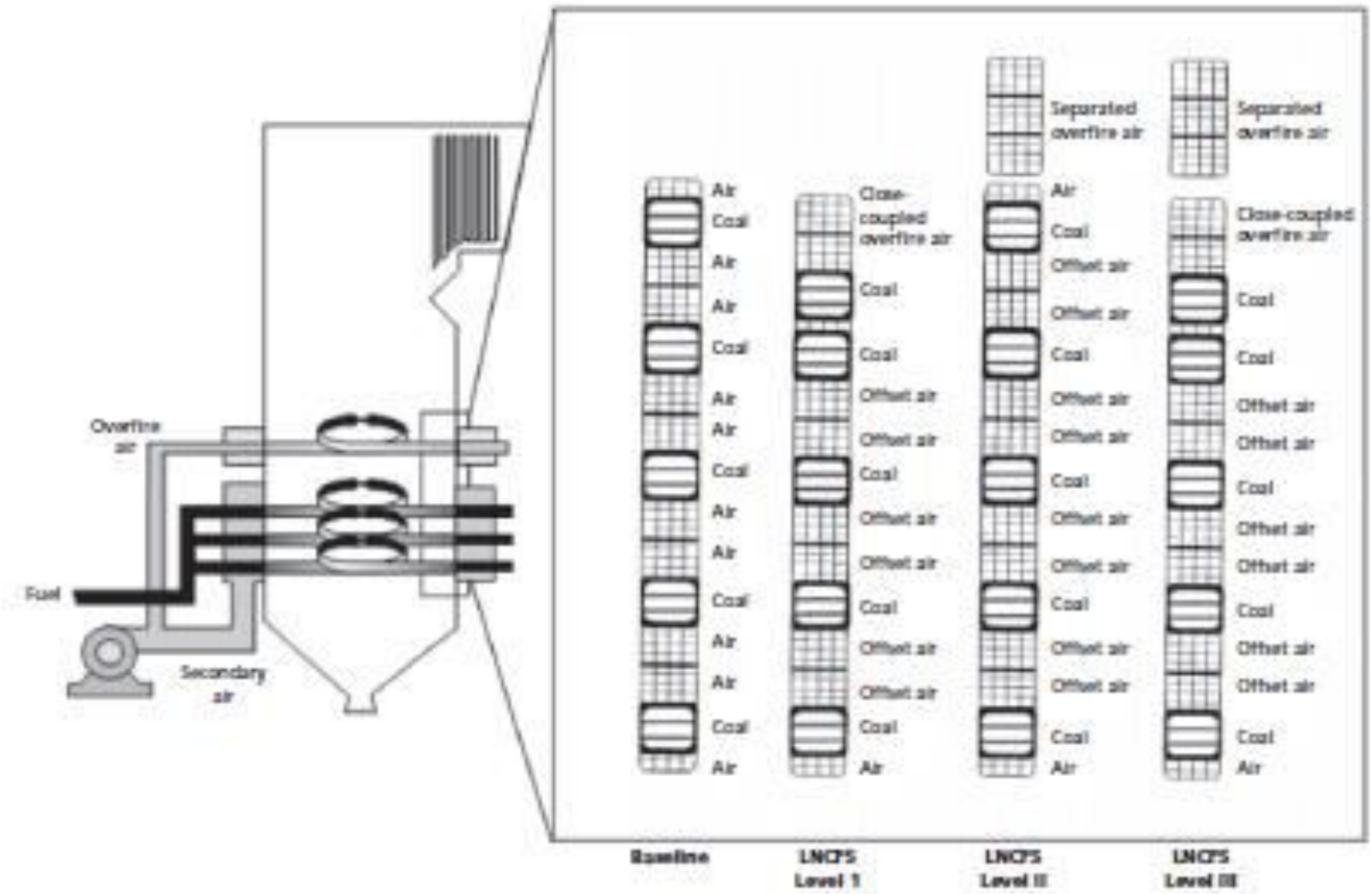
Selective catalytic reduction

Selective non catalytic reduction

Burner modification

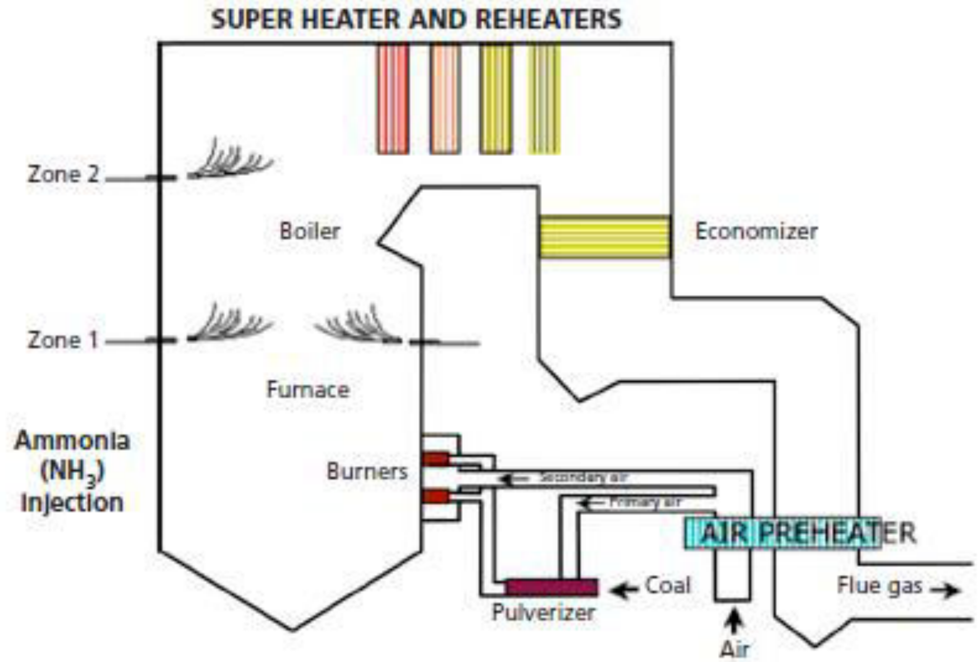
- Low NOx burners are boilers having extra ports to supply air and fuel compared to conventional burners.
- By altering the air–fuel mix, temperatures at different locations in a boiler are kept below a certain level so reaction between nitrogen and oxygen is minimized and relatively lower quantity of NOx is formed.
- These technologies are the basic and most cost-effective control mechanisms.
- The process has a relatively low capture efficiency of around 50 per cent, which means NOx emissions can be cut down to around 400mg/ Nm^3.

Over fire air



Selective non catalytic reduction (SNCR)

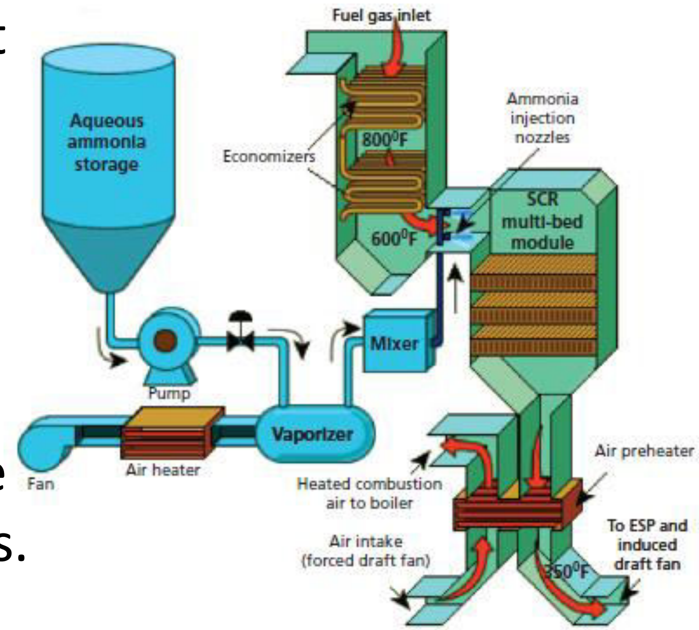
- SNCR reduces NOx by reacting urea or ammonia with the NOx at temperatures of around 900–1,100 °C.
- Urea or ammonia is injected into the furnace in the post-combustion zone to reduce NOx to nitrogen and water.
- Capture efficiency of SNCR is only 25–40 per cent.



Source: NTPC Limited

Selective catalytic reduction (SCR)

- **Would be needed only for upcoming units**
- SCR utilizes ammonia as a reagent that reacts with NOx on the surface of a catalyst. SCR catalyst reactor is installed at a point where the temperature is about 300– 390 °C, normally placing it after the economizer and before the air pre-heater of the boiler.
- The SCR catalyst must periodically be replaced. Typically, companies will replace a layer of catalyst every two to three years. Multiple layers of catalysts are used to increase the reaction surface and control efficiency.
- Emission reduction of up to 90 per cent can be achieved.



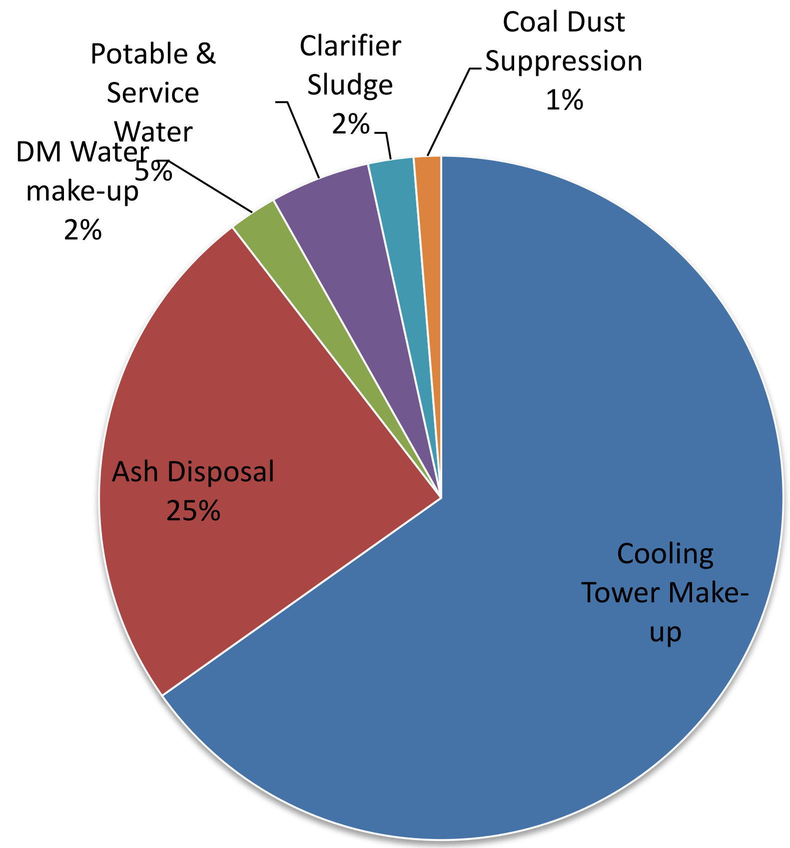
Source: NTPC Limited

SNCR/SCR: Installation time

- SNCR system installation requires about 4 months for a 500 MW unit in a typical situation. The installation includes ducting work near the fire box and construction of a mixing/storage tank.
- SCR system construction involves installation of an aqueous ammonia storage tank, vaporizer, mixer and catalyst bed. The installation period is approximately 5 months for a 500 MW unit in ideal situations.
- Down time for both the technology is approximately 1 month.

Water

- Roughly 35 percent water conventionally is used for other purposes than cooling. (4 – (4*.35)) – making alterations in such a way that the 35 percent demands be met with recycled cooling water
- CESC Budge Budge is operating below 2.5cu.m/MWh
- Cycles of concentration 7 (upto 10 is possible)



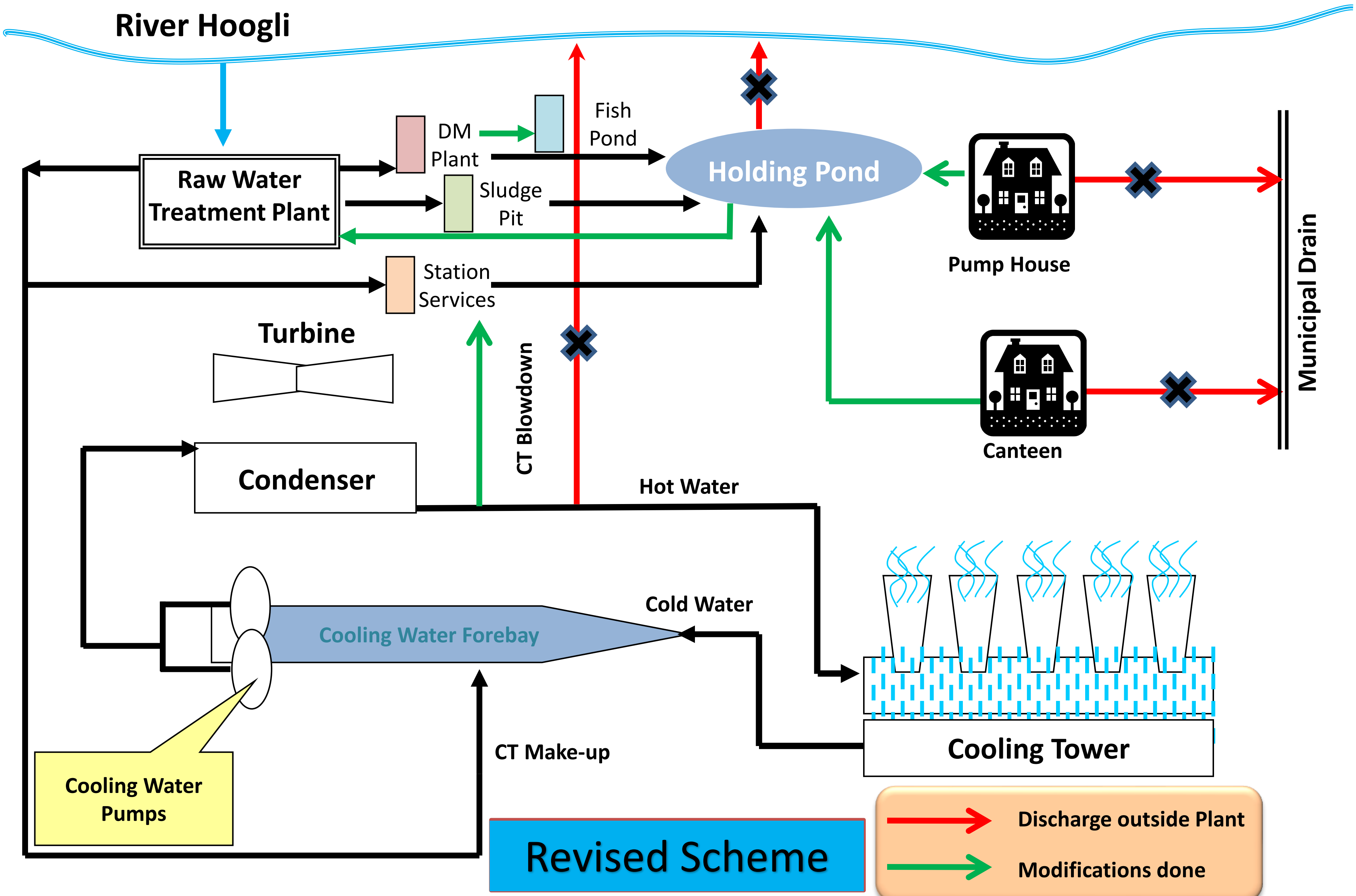
Indian average water use in power plants: 4 cu.m/MWh

Basic Features of Water Management in BBGS

Technology adoption and Initiatives towards Zero Effluent Discharge Power Station

- Zero Discharge System of Bottom Ash Handling
- Dry fly ash evacuation through dense phase system
- Emergency fly ash disposal by HCSD system
- All Volatile Treatment of Boiler water
- Control of Effluent discharge from Raw/DM water treatment Plant
- Use of CT-CW blow-down as service water
- Closed cycle cooling tower with a COC of 6
- Holding Pond for storage, settlement and recycling of Plant Effluent

CESC Budge Budge – Water use layout



Hg Pollution

- Controls designed to remove other pollutants can remove a substantial amount of mercury under certain conditions. For example, the combination of a wet scrubber (FGD designed to remove sulfur dioxide) and selective catalytic reduction (SDR designed to remove nitrogen oxides) have demonstrated mercury removal rates of 70 to 90 percent or more from plants burning high-sulfur bituminous coal.
- Other measures are available aimed at controlling mercury specifically, including chemical additives, such as calcium bromide, which can be used by itself or in combination with activated carbon

OTHER ISSUES

Pollution Monitoring – isokinetic sampling

Maintenance priorities

Coal quality- Ash control

Ash Management

Mercury Control

THANKS