Vales Point - Evaluation of Potential NOx Emission Controls

NOx Pollution Reduction Study - 2021

Final

6 October 2021

Delta Electricity

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Glossary

BAT	Best Available Technologies
BOOS	Burners Out of Service
C	Carbon
CAA	Clean Air Act (US)
CCOFA	Close coupled overfire air
CCR	Carbon capture readiness
CCS	Carbon capture and storage
CE	Combustion Engineering
CEMS	Continuous Emissions Monitoring System
CFBC	Circulating fluidised bed combustion
CFS	Concentric firing system
CID	Carbon-in-dust (also Carbon In Ash, as measured by the Loss on Ignition method)
CO	Carbon monoxide
CO_2	Carbon dioxide
CSAPR	Cross-State Air Pollution Rule (US)
EPL	Environment Protection Licence
EPRI	Electric Power Research Institute (US)
ESP	Electrostatic precipitator

EU	European Union
FGD	Flue gas desulfurisation
FGR	Flue gas recirculation
FY	Financial year
GE	General Electric
GHG	Greenhouse gas
GWh	Gigawatt hour
H_2O	Water
HGI	Hardgrove Grindability Index
ICAL	International Combustion Australia Ltd
IED	Industrial Emissions Directive (EU)
IPC	Infrastructure Planning Commission
IPPC	Integrated Pollution Prevention and Control
kg/GJ	kilograms per gigajoule
lb/MMBtu	Pounds per million British thermal unit
LBL	Load Based Licensing
LHS	Left hand side
LLD	Limited Lifetime Derogation
LNB	Low NO_x burners
MATS	Mercury and Air Toxic Standard Rule (US)
mg/m^3	Milligram per cubic meter
mg/Nm^3	Milligram per cubic meter under normal conditions (i.e. 0°C and 1 atmospheric pressure)
MW	Megawatts
MWe	Megawatt electrical
MWt	Megawatt thermal
Nm^3	Normal Meters Cubed – refers to gas volume at 0°C and 1 atmosphere, on dry basis.
N_2	Nitrogen gas
NN	Neural Networks
NAAQS	National Ambient Air Quality Standard
NESHAPS	National Emissions Standards for Hazardous Air Pollutants
NO_X	Nitrogen Oxides, specifically the sum of NO and NO_2
NO_2	Nitrogen dioxide
NO	Nitrogen oxide
NPS	National Policy Statement
NSPS	New Source Performance Standards
O_2	Oxygen gas
OEM	Original Equipment Manufacturer
OFA	Overfire Air; combustion air fed into the furnace above the burner level
PC	Pulverised coal
PF	Pulverised fuel
PFBC	Pressurised fluidised bed combustion
PM	Particulate matter
$PM_{2.5}$	Particulate matter with an aerodynamic diameter of less than 2.5 microns
ppm	Part-per-million
PRS	Pollution Reduction Study
ROFA	Rotating Opposed Fire Air
SCR	Selective Catalytic Reduction

SIPS	State Implementation Plan
SNCR	Selective non-catalytic reduction
SGN	Selective guidance note
SOFA	Separated overfire air
T-fired	Tangentially fired boilers
TNP	Transitional National Plan
U1	NOx Investigation Study required to satisfy EPL761
UK	United Kingdom
US EPA	United Stated Environmental Protection Agency
VOC	Volatile organic compounds
$M	Million dollars
$/MWh	Dollars per Megawatt hour
$/tonne	Dollars per tonne
% O_2	Percentage oxygen content by volume

Executive Summary

Vales Point Power Station (VPPS) is a 2 unit coal fired power station owned and operated by Sunset Power International Pty Ltd trading as Delta Electricity (Delta). VPPS is located on the NSW Central Coast with a gross installed capacity of 1,320 megawatts, commissioned in 1978/79 under Group 2 emission regulations. Delta holds an Environment Protection Licence (EPL) No. 761 for Vales Point.

Delta has recently submitted a Licence Variation Application (LVA) to the EPA. The LVA is to extend the exemption of Group 5 standards of concentration for nitrogen oxides (NOx) emissions from the Vales Point (VPPS) Units 5 and 6. The EPA have requested a report on benchmarking and evaluation of potential NOx emission control or mitigation measures.

The first edition of the Jacobs pollution reduction study (PRS) in 2017 was a condition to the licence Variation Notice No. 1535318 issued on 14 December 2015. A review of literature was conducted to identify any operational practices or post-combustion NO_X controls which could be implemented to permit NOx concentrations to 3 different levels (800 mg/Nm^3, 500 mg/Nm^3 and <500 mg/Nm^3). The report also provided an overview of existing studies undertaken by Delta that demonstrate their management of NO_X emissions at Vales Point.

This second edition is in response to the EPA specific request to update/expand on the 2017 Vales Point NOx Emission Control Investigation Pollution Reduction Study (PRS) prepared by Jacobs with the incorporation of the additional requests of the EPA, outlined in **Section 1.3**. This report expands and updates the literature review, includes records of the NOx emission data for the period July 2017 to August 2021 and projects emissions to retirement in FY2029. It also provides an overview of Delta's continuing management of NOx emissions. The report completes a further review of operational practices or post-combustion NO_X controls.

Operational improvements have reduced NOx emissions significantly in 2021. Unit 6 major overhaul, burner tip replacement has reduced the U6 NOx concentration emissions from 769 mg/Nm^3 to 532mg/Nm^3 (refer **Section 5.1**). In addition, the 2021 IP turbine upgrade improved heat rate 1.9%, corresponding to 1.9% reduction in NOx mass emissions.

A further review of additional NO_X controls, and the technical feasibility thereof, is summarised in **Table 1-1** below. Some additional assessment would be needed to see if these could be implemented at Vales Point with respect to integrating with existing plant. For further details on technical feasibility, refer **Section 8.**

Table 1-1: Feasibility of Control Options

Base Case	Option i) 800 mg/Nm³	Option ii) 500 mg/Nm³	Option iii) <500 mg/Nm³	Comment
Unit 5 (current)	> 99%	Not feasible		Achieves 800 mg/Nm³ >99.6% of time (2017-2021), with a maximum of 922 mg/Nm³ in 2021. High carbon in dust (CID) and boiler efficiency loss. Not possible to guarantee 800mg/Nm³ all the time
Unit 6 - return to conventional burner tips (June 2021-August 2021)	> 99%	Not feasible		32% reduction in NOx production, but increased carbon in dust (CID) to average 3.6%[48]. CID within accepted resale limits. Achieves 800 mg/Nm³ >99.7% of time, with maximum of 976 mg/Nm³. Not possible to guarantee 800mg/Nm³ all the time
NOx Control Mechanism	**800 mg/Nm³**	**500 mg/Nm³**	**<500 mg/Nm³**	**Comment**
Burner optimisation for NOx control using staging air	< 100% *	Not feasible		* Expected to reduced average NOx production, and % of time achieving 800 mg/Nm³. Not possible to guarantee 800mg/Nm³ 100% the time
Neural Network	< 100% *	Not feasible		* To be confirmed by suppliers Expected to reduced average NOx production, and % of time achieving 800 mg/Nm³. Not possible to guarantee 800mg/Nm³ 100% the time
Low NOx burners	Yes *	Possible*	Not feasible	* To be confirmed by potential non-OEM suppliers. OEM no longer supplies within Australia. (may not be guaranteed for 100% of the time)
Selective non-catalytic reduction (SNCR)	Yes	Yes		Ongoing additional operating cost and ammonia slip emissions and air heater fouling.
Selective Catalytic reduction (SCR)	Yes	Yes	Yes	Used only in conjunction with Low NOx burners Ongoing additional operating cost and ammonia slip emissions
Over-fire air (OFA)	Not feasible			Limited impact, but not a means of controlling NOx to limits
Flue gas recirculation (FGR)	Not feasible			Physical gas path constraints mean additional gas flow not practical
Biomass Co-firing	Not feasible			NOx reduction potential is estimated at 2% for 3% cofiring. Reduces average NOx only

Five of the above NOx controls appear technically feasible to achieve 800 mg/Nm³ and two appear potentially able to achieve 500 mg/Nm³ or less, as follows:

i. Burner optimisation for NOx control using air staging

ii. Low NOx burners (from non-OEM supplier, as GE no longer supply LNB in Australia)

iii. Selective non-catalytic reduction (SNCR)

iv. Selective Catalytic reduction (SCR)

v. Neural Network technologies

An updated cost evaluation was undertaken for the potential NOx control options, with costs determined as capital costs (capex) and operating and maintenance (O&M) costs (refer **Section 9.3**).

The incentive to reduce NOx emissions are the Load Based Licensing (LBL) fees. An assessment of the LBL fees has been made from FY2022-2029, which is the year the current Group 5 exemption expires to FY2028-29 when Delta forecast the power station will cease operation. **Table 1-2** below, summarises the cost analysis for the feasible control options identified.

Table 1-2: Cost Analysis of Potential NOx Controls Options Retrofitting

NOx Control Mechanism	Effectiveness (max. emissions reduction potential)	Capital Cost for Retro-fitting ($M/unit)	O&M Costs ($/MWh)	Generation U5&U6 GWh (2022-2029)	O&M Costs U5&U6 FY22-FY29 ($M)	Total Cost ($M) (Capex + 2022-2029 Opex) (1)	LBL Fees Saved ($M)
Burner Optimisation for NOx control	Up to 10%	6	0.05	50,049	2.5	14.5	1.1
Low NOx burners & OFA	Up to 50%	42	0.2	50,049	10	94	5.6
SNCR	50%	28	3.4	50,049	170	226	5.6
SCR	85%	120	2.4	50,049	120	360	9.5
Neural Network	Up to 10-15%[1]	3.0	0.012	50,049	0.6	6.6	1.7

Note: Maximum emission reduction potential is subjective and variable for retrofits projects. LBL fee is based on the lower NOx emission levels after the removal of the wide range burner tips from Unit 6 in June 2021.

(1) The total capital cost in 2017 report Table 8-3 incorrectly captured only a single unit capex as opposed to 2 units.

The NOx reduction measures outlined considered feasible for implementation when considering both the technical and cost implications are :

- Combustion optimisation (Continued - refer to **Section 8.1**)
- Cofiring of up to 3% biomass

None of the above measures would guarantee less than 800mg/Nm^3 100% of the time.

The other listed NOx mitigation or control measures options in **Table 1-1** are not considered feasible primarily due to the total estimated costs for retrofitting far outweighing the saving in LBL (Load Base Licensing) fees that can be achieved. These high capex cost options to mitigate NOx cannot be accommodated by a utility nearing retirement. This expenditure is also not considered warranted considering:

- The absence of an OEM supplier or competent retrofit partners in Australia due to their withdrawing from the coal fired energy market
- The progressive decline in the emissions from Vales Point as power generation as demand from the pulverised coal base load utility decreases to end of life in FY2029
- The level of impact the power station has on the ambient air quality within the regional area which is outside any critical zone (refer Appendix C 2017 report).

[1] Neural networks prove effective at NOx reduction, Article from NS Energy, 19 May 2000

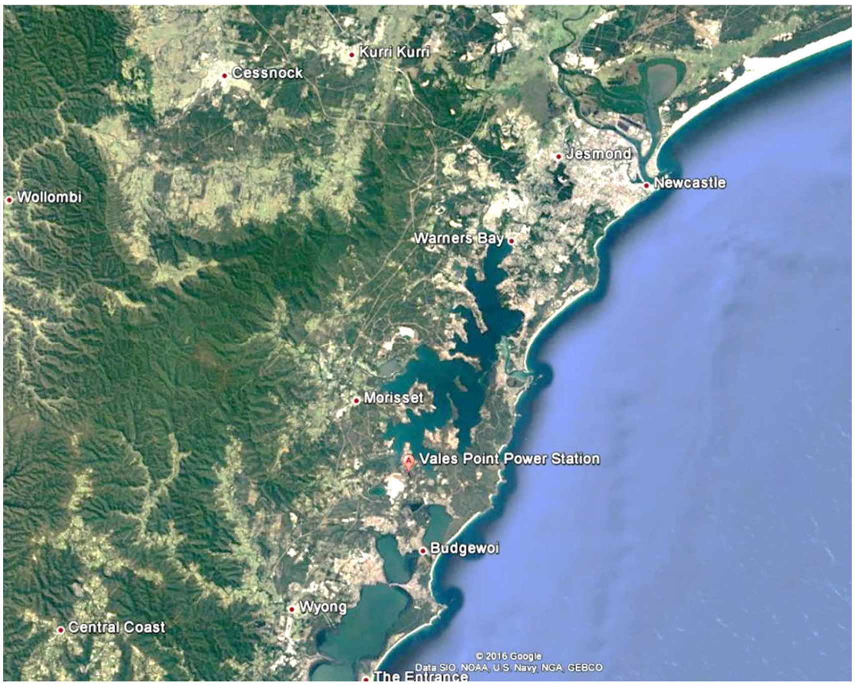
1. Introduction

1.1 General Introduction

Vales Point Power Station (Vales Point) is owned and operated by Sunset Power International Pty Ltd trading as Delta Electricity (Delta). Vales Point is located on the NSW Central Coast (refer to **Figure 1-1**) with a gross installed capacity of 1,320 megawatts.

Vales Point is a coal-fired power station providing baseload electricity. It consists of 2 boiler-turbine units designated Units 5 and 6 (U5, U6), with the original A station Units 1-4 having been retired in 1989.

Figure 1-1 Vales Point Power Station Locality Plan



Delta holds an Environment Protection Licence (EPL) No. 761 for Vales Point and Coal Unloader issued under Section 55 of the Protection of the Environment Operations (POEO) Act 1997.

The EPL authorises Delta to carry out scheduled, fee based and other activities at the premises.

The EPL includes monitoring and/or setting of limits for emissions of pollutants discharged to air, water or land. Also included are a range of conditions, from the general requirement to operate in a competent manner and the maintenance of plant and equipment.

The current version of EPL No. 761 is dated 23 July 2020 and the NOx emission limits remain valid until January 2022 unless surrendered, suspended or revoked. The conditions of the EPL can be renegotiated or updated at any time during the licence period following discussions between the EPA and the licence holder.

1.2 Background

Licence Variation Notice No. 1535348 was issued by the EPA on 14 December 2015 with the following conditions:

- the existing licence NOx limit of 1,500 mg/m^3 (condition L3.4) would be retained for a further five years until 1 January 2022 (condition L3.6); and

- licence condition U1 required a pollution reduction study (PRS) for an 'Investigation of further controls to reduce nitrogen oxide emissions' for Vales Point. (Jacobs PRS report dated 29 June 2017)

1.2.1 Current project

Delta has recently submitted a licence variation application (LVA) to the EPA, in advance of the current license expiry (1 Jan 22). The LVA is to vary condition L3.8 of the Vales Point EPL, extending the exemption of Group 5 standards of concentration under the POEO (Clean Air) Regulation for nitrogen oxides (NOx) emissions from Vales Point Power Station (VPPS) Units 5 and 6.

NSW EPA has advised Delta that it requires additional information in order to assess the LVA. One of the additional requirements is to update/expand on the 2017 PRS Study[2] prepared by Jacobs. Specifically, the EPA have requested benchmarking and further evaluation of potential emission controls or mitigation measures. Delta Electricity engaged Jacobs to complete this work.

1.3 Scope of Work

The 2021 scope of work is as follows (with report paragraph references)**:**

a) a detailed description of existing air pollution emission controls (refer **Section 2**) and management measures used in conjunction with coal fired boilers at the VPPS premises; (refer **Section 4)**

b) benchmark existing VPPS air pollution controls, emission performance (refer **Section 5**) and emission limits against coal fired power stations in NSW and other jurisdictions both in Australia and internationally. The benchmarking must have regard for plant vintage, boiler configuration and technology and receiving environment; (refer **Section 7**)

c) provide a detailed feasibility evaluation of additional NOx emission control, or mitigation measures that are not currently used at the VPPS. For the purpose of this requirement, the EPA has taken feasibility to be what is technically possible to be implemented at the premises from an engineering perspective;

   I. Detail the additional analysis that has been conducted to update, expand and extend the analysis of potential controls identified in the document titled: *Vales Point Power Station (Delta Electricity) NOx Pollution Reduction Study (PRS) Final Report (2017)*; required by Condition U1 of the EPL No. 761. (refer **Section 8**)

   II. As a minimum, consideration must be given to the following NOx emissions controls:

      (1) Combustion optimisation (refer **Section 8.1**)

      (2) Low NOx Burners (refer **Section 8.4**)

      (3) Selective non-catalytic reduction (SNCR) (refer **Section 8.5**)

      (4) Selective Catalytic reduction (SCR) (refer **Section 8.6**)

      (5) Other potential options beyond operational changes

d) based on the evaluation in item c (above), identify feasible measures that could be implemented to reduce NOx emissions at the premises, and; (refer **Section 9**)

e) for each mitigation measure evaluated in item c (above) that is determined not to be feasible for implementation, detailed justification with supporting evidence on why these measures are not feasible for implementation must be provided.

[2] 2017 Vales Point NOx Emission Control Investigation Pollution Reduction Study – dated 29 June 2017, by Jacobs

The 2017 report scope:

U1 Investigation of further controls to reduce Nitrogen Oxide Emissions

U1.1 Aim - The aim of this pollution reduction study is to assess the feasibility of achieving reductions in the emissions of nitrogen oxides at the premises.

U1.2 The licensee must undertake a review of international best practice measures to minimise the generation, and emission, of nitrogen oxides (NOx) from coal fired electricity generation.

U1.3 The licensee must identify control techniques, including both combustion and post combustion options, for achieving the following NOx emission concentrations from electricity generating unit(s) at the premises:

(i) 800 mg/m3 (dry, 273 K, 101.3 kPa, 7% 02), equivalent to Protection of the Environment Operations (Clean Air) Regulation Group 5 limit;

(ii) 500 mg/m3 (dry, 273 K, 101.3 kPa, 7% 02), equivalent to Protection of the Environment Operations (Clean Air) Regulation Group 6 limit; and

(iii) <500 mg/m3 (dry, 273 K, 101.3 kPa, 7% 02), consistent with international best practice.

U1.4 The licensee must assess and evaluate the feasibility of implementing control options identified in U1.3(i) - (iii). Evaluation must have regard for, as a minimum, cost, timing, emission performance and technology and engineering considerations.

U1.5 The licensee must submit a consolidated report, prepared by a suitably qualified person, which addresses the requirements of U1.1, U1.2 and U1.3.

2. Vales Point Boiler Description

2.1 Overview

NOx emissions (primarily NO (+95%) but also NO_2) are formed during the combustion process in the boiler. This section provides a general overview of the Vales Point boilers, including description of key processes associated with air pollution emissions and their control.

The technical specification for VPPS is provided in **Appendix A**.

2.2 Boiler Description

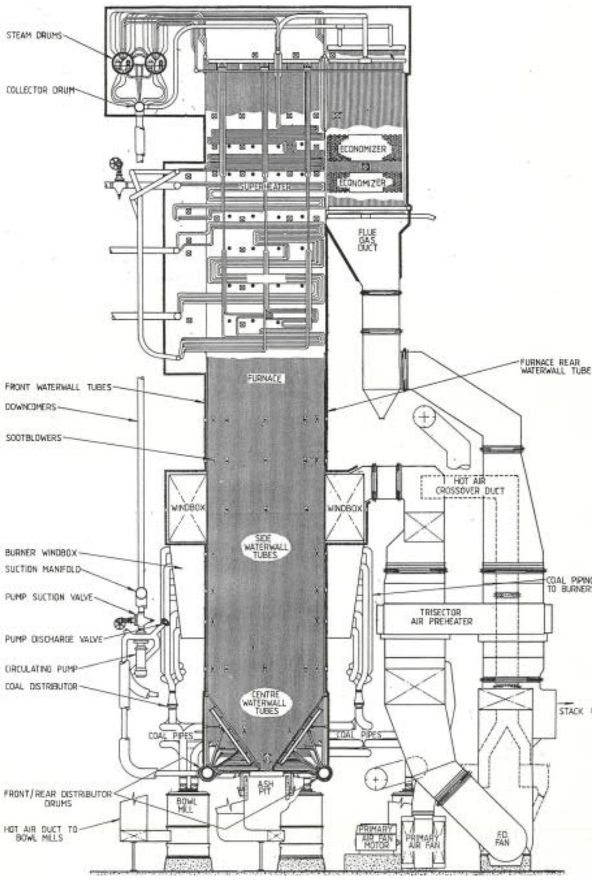
Vales Point consists of 2 x 660MWe pulverised coal fired, single reheat, subcritical units. The boilers are International Combustion Australia Ltd (ICAL) manufacture, tangentially fired, twin furnace, two pass design, with fabric filters for particulate control and connected to a common stack. ICAL built the boilers under license from Combustion Engineering (CE), who was later acquired by ABB, Alstom and now is part of General Electric (GE).

The boilers have a high furnace volumetric rating, which means a short residence time for combustion, and high carbon in ash levels. The boilers have high flue gas velocities which leads to high gas path erosion.

Coal is sourced from local mines, primarily Chain Valley Colliery and Mandalong Colliery, and also Airlie from Lithgow.

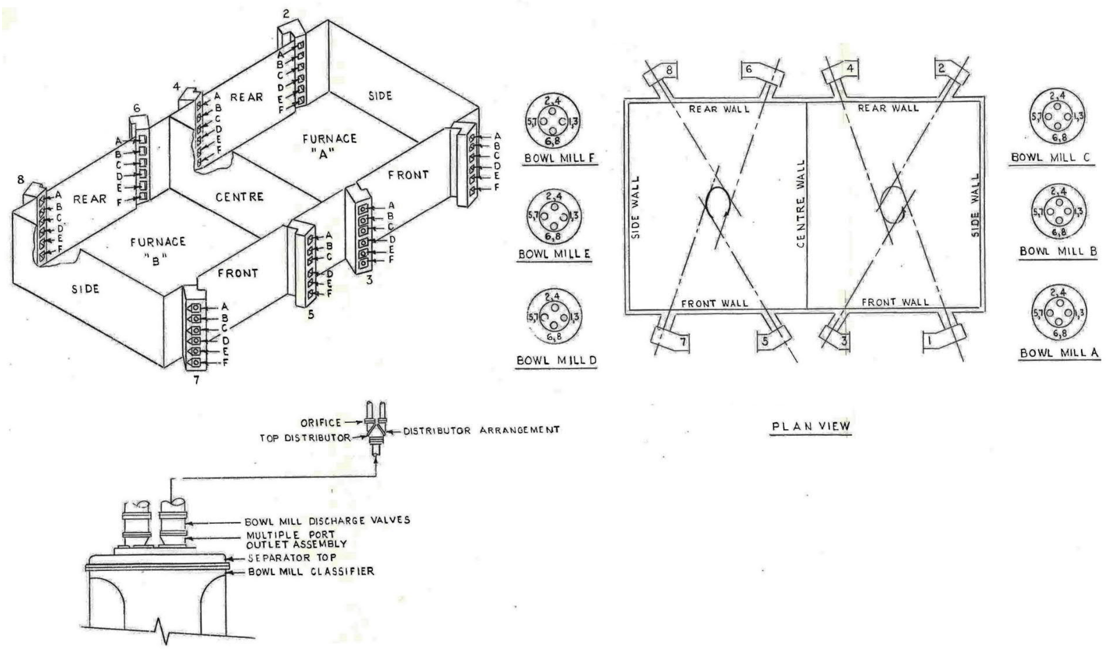
Figure 2-1 indicates the major parts of the boiler. The boiler is a two pass design, with twin furnaces (A and B), radiant and convective superheaters and reheaters in the upper furnace, with economiser and twin rotary airheaters in the backpass. The boiler steam conditions are 16.5MPa 540°C representing good practice for subcritical units.

Figure 2-1 Sectional Elevation of Vales Point Boiler



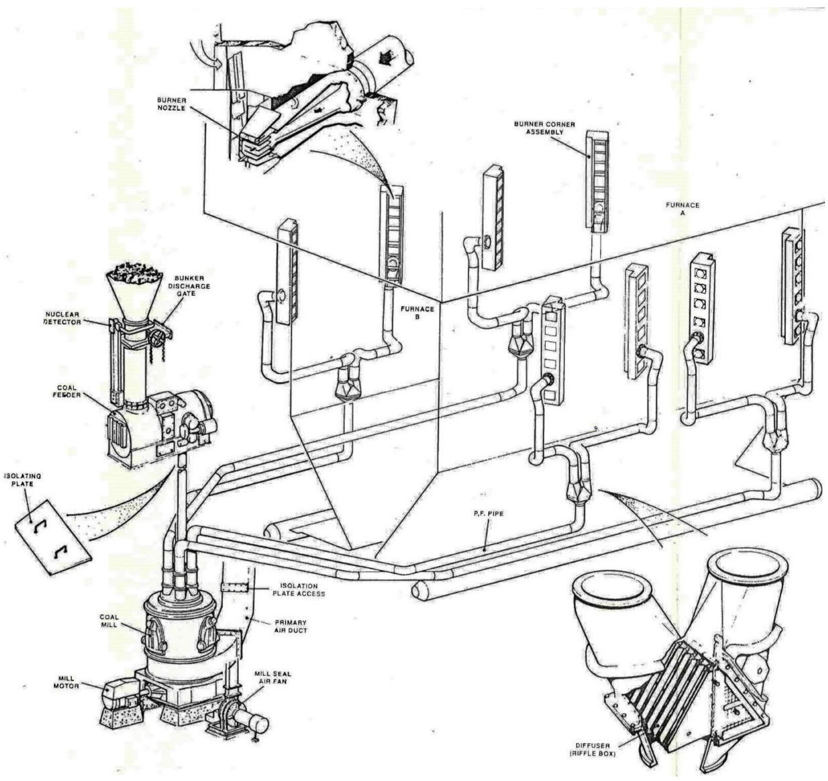
Each furnace has 4 corner fired burners, with 8 burners per level. There are 6 levels of burners, and 48 burners in total. There are 6 pulverised coal (bowl) mills in total (A-F) with each mill feeding its own burner level. The outlet pipes from each mill are split into 2 via distributors (riffle boxes), so that the 4 outlet pipes feed 8 burners. A diagram showing the arrangement of the furnace and burners is shown in **Figure 2-2** below. The burners are able to tilt up and down to provide control of reheat temperature.

Figure 2-2: Furnace and Burner Arrangement



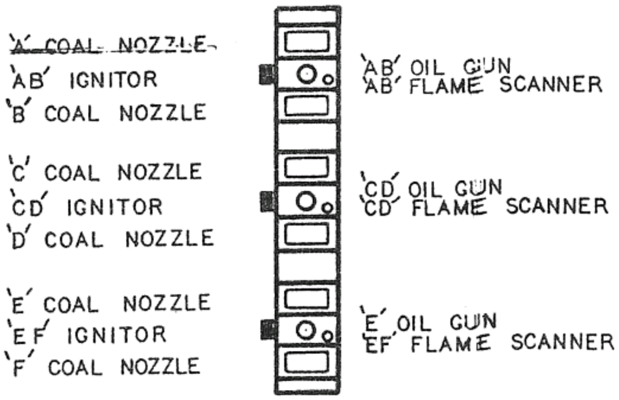
A diagram of the coal feeder, mill and burner is shown in **Figure 2-3**.

Figure 2-3: Diagrammatic of Coal Feeder, Mill, Riffle box and Burners



Each burner consists of a primary air / coal nozzle, surrounded above and below by secondary air nozzles. The burner corner assembly (refer to **Figure 2-4**) consists of all 6 levels of burners (A -F) in a single assembly, coupled with secondary air nozzles.

Figure 2-4 Corner Windbox and Burner Assembly



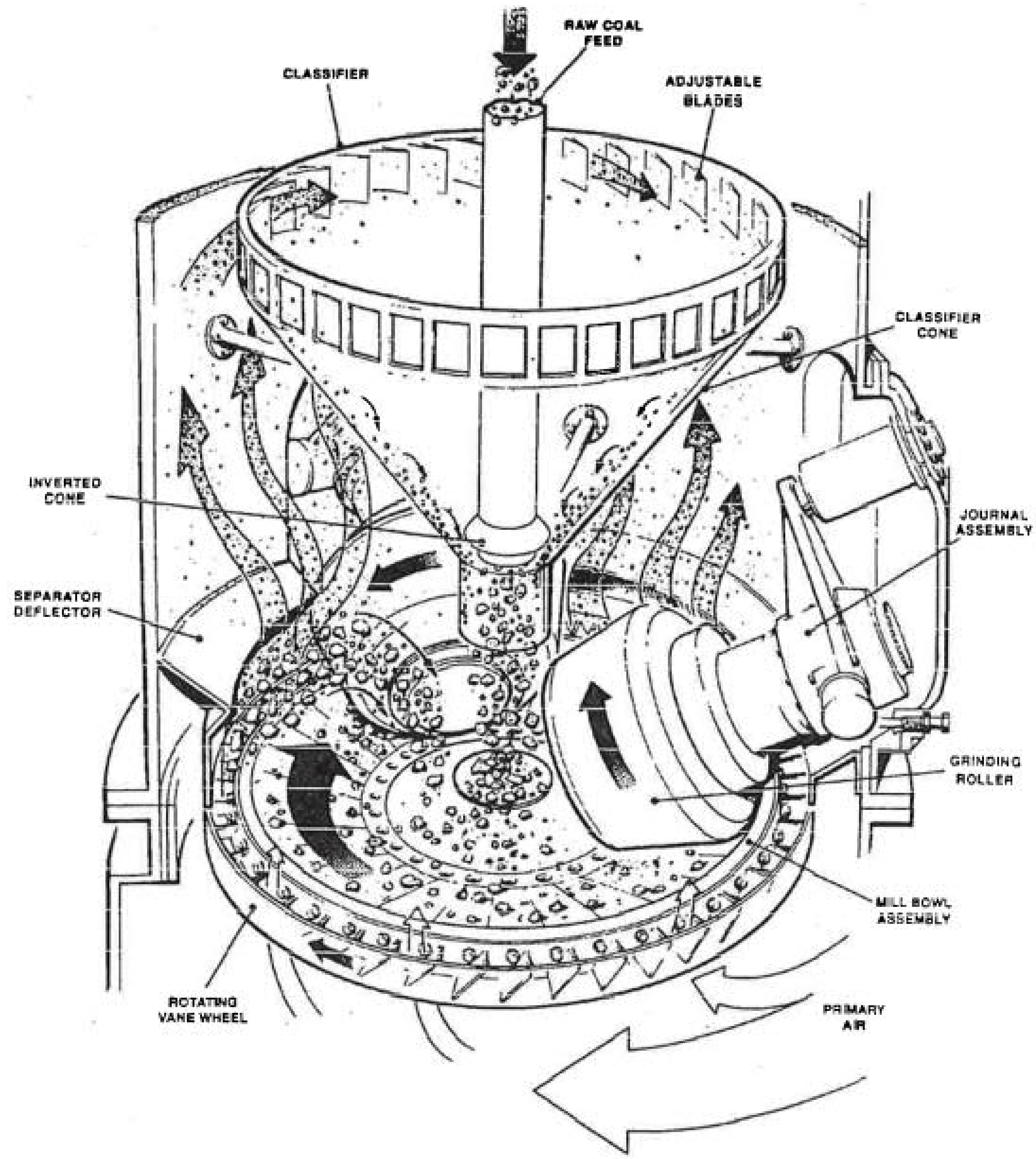
In 2012, the "wide range tips" were installed on Unit 6 for the purpose of reducing carbon in dust, thereby improving plant efficiency and reducing greenhouse gas (GHG) intensity. In addition, reducing carbon in dust provides assurance of the fly ash being able to be reused as a cement additive, an important waste recycling element of the power station operations, and reduces GHG from cement production.

A downside of the wide range burner coal nozzle tips on Unit 6 is that they resulted in an increase in NOx emissions of approximately 90 ppm (180 mg/Nm^3) and a corresponding increase in the load based licensing fee for NOx emissions. The OEM (GE) had claimed that the wide range tips would improve boiler efficiency by reducing carbon in dust levels, while having a negligible impact on NOx. However, they were unable to achieve the same NOx levels as per the conventional nozzles. In mid-2021, the wide range burner tips were removed from Unit 6, and conventional tips were reinstalled. This has significantly reduced NOx emissions from the unit but increased the carbon in dust to approximately 3.6%[3].

The 6 coal pulverisers (mills) are Raymond Bowl mill type, with a rotating table (refer **Figure 2-6** below). The classifier has fixed vanes. The original mills had insufficient capacity and were replaced with a larger model. The boiler was designed to achieve full load with 5 of 6 mills in service, based on the design coal. The number of mills operating can depend on the coal quality and particular conditions (e.g. wet coal, mill configuration), which determines how many mills are required to achieve optimal full load operation. In general, five mills are required to achieve full load. However, if six mills are in-service, carbon-in-dust (CID) has been reported by Delta to be lower and efficiency and NOx emissions noted to be higher. This indicates the milling plant at VPPS has less than desirable capacity.

[3] Average of Morgan Ash Test Report Data for period 1/7/2021 to 21/8/2021, forwarded by VPPS on 24/8/2021

Figure 2-5: Pulverised Coal Mill operation



2.2.1 Boiler Performance Data

The basic performance data for the Vales Point boilers is given in **Figure 2-6** below:

Figure 2-6 : Boiler Performance

Load		Control Load	Guar Load	M.C.R.
Fuel		Coal	Coal	Coal
Evaporation	kg/s	390.5	531.6	560.5
Feed Water Temperature	°C	233	252	254
Superheater Outlet Temperature	°C	541	541	541
Superheater Outlet Pressure	kPa	16536	16536	16536
Superheater Pressure Drop	kPa	655	1130	1240
Reheater Flow	kg/s	365.3	473.6	496.3
Reheater Inlet Temperature	°C	338	345	347
Reheater Inlet Pressure	kPa	2908	4065	4272
Reheater Outlet Temperature	°C	541	541	541
Reheater Outlet Pressure	kPa	2777	3893	4093
Reheater Pressure Drop	kPa	131	172	179
Economiser Pressure Drop	kPa	262	358	379
Gas Drop, Furnace to Economiser Outlet	kPa	0.67	1.15	1.29
Gas Drop, Economiser Outlet to Air Heater Outlet	kPa	0.78	1.17	1.27
Gas Temperature Entering Air Heater	°C	293	310	316
Gas Temperature Leaving Air Heater, Uncorr.	°C	105	119	121
Gas Temperature Leaving Air Heater, Corr.	°C	99	111	113
Air Temperature Entering Air Heater	°C	18	18	18
Air Temperature Leaving Air Heater	°C	238	242	246
Air Pressure Entering Air Heater	kPa	1.4	1.83	2.08
Ambient Air Temperature	°C	18	18	18
Excess Air Leaving Economiser	%	20	17.6	17.6
Efficiency	%	89.44	89.03	88.93

2.3 Description of Boiler Combustion

The boiler fires coal which consists of combustibles elements (carbon, hydrogen and minor amounts of sulfur) and non-combustible material (ash, water and oxygen). For combustion to occur, fuel and oxygen need to be mixed as thoroughly as possible. For this reason, the coal is ground to a fine powder (pulverised) in the coal mills. The air used to transport the coal to the furnace, is called primary air. The main combustion air (called secondary air) is added into the furnace adjacent to the coal nozzles, and mixing occurs in the furnace. The tangential orientation of the burners creates a swirl in the furnace, which promotes further mixing (refer **Figure 2-2**).

For optimum combustion, the coal and air need to be mixed in the correct ratio. The exact ratio is called stoichiometric, however it requires perfect mixing of fuel and air which is impractical. Therefore, excess air (above stoichiometric) is used. Too little excess air leads to unburnt fuel, and too much excess air leads to loss of heat up the boiler stack. The optimum excess air is typically 15-20%, which is equivalent to 3% O_2 by volume, as measured in the flue gases before the airheater. Excess air also reduces the flame temperature and reduces the amount of thermal NOx produced.

Two rotary airheaters (gas path A and B) are installed to extract the last energy from the flue gases and to preheat the combustion air. (The rotary airheaters metal plates heat up as they pass through the hot flue gas duct. The plates then rotate into the combustion air duct, where they heat the incoming cold combustion air, and the cycle repeats). There is some inevitable leakage of the combustion air (at positive pressure) into the flue gases (at negative pressure) around the airheater casing and seals. Therefore, the oxygen concentration in the flue gas after the air heater rises to 6-10% by volume.

Air in-leakage can occur at many other places, as the boiler gas path is maintained at negative pressure. This can include, access and inspection doors, expansion joints, piping penetrations, fabric filter casing etc. This in-leaking air dilutes the flue gases and also the NOx emissions. For this reason, all emissions in flue gas are corrected to a standard oxygen concentration, to avoid apparent emissions reduction by dilution. Most international jurisdictions correct emission concentrations (normalise) to a standard oxygen concentration of 7%O_2 by volume dry flue gas. This has also been adopted by NSW EPA.

2.4 NO_x Formation and Emission

There are a variety of different oxides of nitrogen. NOx is used to represent the summation of NO and NO_2, the latter being an air pollutant and hence the subject or regulation for the purpose of managing ambient air quality impacts. In general, NOx emissions are reported as NO_2 equivalent.

There are three sources of NO_X emissions that result from the firing of fossil fuels. The primary source is the fixation of atmospheric nitrogen in the flame (thermal NO_X) caused by the disassociation of atmospheric oxygen and nitrogen at high temperature (above 1,000°C). A secondary source of NO_X arises from fuel-bound nitrogen (fuel NO_X) and becomes more significant in fuels with low calorific value. Finally, prompt NO_X is formed from the fast oxidation of hydrocarbon radicals near the combustion flame, which generally produces only minor amounts of NOx in coal fired boilers. These three sources are discussed in further detail below:

Thermal NO_X is a function of the temperature of the flame, the oxygen concentration, and the time the hot gases remain at the high temperature. Called the extended Zeldovich mechanism, a simple explanation is that thermal NO_X increases exponentially with the temperature of the reaction, linearly with the residence time and as a square root function of the oxygen concentration.

Fuel NOx is also a minor contributor to NOx formation. There is no means of reducing the nitrogen content of coal, aside from sourcing alternate fuel supplies (no known supplies). The fuel nitrogen content is typically 1-2%., and so doesn't represent a large opportunity for reduction. There is no simple relationship between nitrogen content, and NOx formation, and so there is less justification for fuel substitution to control NOx emissions than sulfur emissions. Coals which have high volatile contents, generally exhibit lower NOx formation. The nitrogen which is released in the volatiles is reduced to N_2 under fuel rich conditions, and is oxidised under lean burn conditions to NO. Because fuel NOx is only a minor contributor to NOx emissions, it is not an effective means of controlling NOx emissions.

Prompt NOx formation occurs rapidly in the flame (hence the name "prompt") and there is no ability to quench its formation unlike thermal NOx.

The following options are potentially available for the control of NOx in general for coal-fired power stations:

- **Stoichiometric based combustion controls:** where the ratio and mixing of air (oxygen) to fuel is controlled to modify the concentration of oxygen in the flame zone;
- **Flame Dilution based combustion controls:** where the flame temperature of combustion is reduced using recirculated flue gas, or other fluid like steam;
- **Post combustion control:** where the flue gas is cleaned up following combustion.

Each of these control options is discussed in more detail in Section 7.

2.5 Boiler Air Pollution Controls

The air pollution controls at VPPS consist of a Continuous Emissions Monitoring System (CEMS), a fabric filter for particulate emission control, stack for flue gas dispersion, combustion controls and fuel management.

The CEMS, records emissions to air for SOx NOx, and CO and reports on an hourly basis, with the emissions reported in mg/Nm^3 and corrected to 7% O_2. There are 4 separate CEMS sampling points (Unit 5A and 5B, Unit 6A and 6B), which are in the flue gas ducts immediately prior to the stack penetration.

A fabric filter is installed in the A and B passes of each boiler to control particulate emissions. Combustion controls ensure the fuel air ratio is kept within safe limits. The operators monitor the combustion to ensure the NOx and CO levels are kept within the required limits. The fuel quality is monitored by regular sampling and low sulfur fuel is used to limit SOx emissions. The flue gas temperature and the height of the stack ensures the safe dispersion of the fuel gases, which are primarily N_2, CO_2, H_2O and O_2.

3. NSW Air Pollution Regulations

3.1 Overview

This section of the report provides an overview of the NSW Protection of the Environment Operations (Clean Air) Regulation 2010 (Clean Air Regulation) and Vales Point Environment Protection Licence (EPL No. 761).

3.2 NSW Clean Air Regulation

Stack emissions from Vales Point are subject to regulation under the NSW Clean Air Regulation. In terms of air pollution emission requirements, these are grouped (Group 1 to 6) based plant commissioning date as follows from the Clean Air Regulation:

32) General groupings of activity and plant:

Subject to this Division, an activity carried out, or plant operated, on scheduled premises:

a) belongs to Group 1 if:

i. it commenced to be carried on, or to operate, before 1 January 1972, or

ii. it commenced to be carried on, or to operate, on or after 1 January 1972 as a result of a pollution control approval granted under the Pollution Control Act 1970 pursuant to an application made before 1 January 1972, or

b) belongs to Group 2 if it commenced to be carried on, or to operate, on or after 1 January 1972 as a result of a pollution control approval granted under the Pollution Control Act 1970 pursuant to an application made on or after 1 January 1972 and before 1 July 1979, or

c) belongs to Group 3 if it commenced to be carried on, or to operate, on or after 1 July 1979 as a result of a pollution control approval granted under the Pollution Control Act 1970 pursuant to an application made on or after 1 July 1979 and before 1 July 1986, or

d) belongs to Group 4 if it commenced to be carried on, or to operate, on or after 1 July 1986 as a result of a pollution control approval granted under the Pollution Control Act 1970 pursuant to an application made on or after 1 July 1986 and before 1 August 1997, or

e) belongs to Group 5 if it commenced to be carried on, or to operate, on or after 1 August 1997 as a result of:

i. a pollution control approval granted under the Pollution Control Act 1970 pursuant to an application made on or after 1 August 1997 and before 1 July 1999, or

ii. an environment protection licence granted under the Protection of the Environment Operations Act 1997 pursuant to an application made on or after 1 July 1999 and before 1 September 2005, or

f) *belongs to Group 6 if it commenced to be carried on, or to operate, on or after 1 September 2005, as a result of an environment protection licence granted under the Protection of the Environment Operations Act 1997 pursuant to an application made on or after 1 September 2005.*

Based on the age of Vales Point it was originally assigned to Group 2 plant under the CAPER, 2010.

Clause 35 of CAPER, 2010 sought to phase out Group 2 plant and move to Group 5 as follows:

35) Phasing out of Group 2

1) On and from 1 January 2012, any activity or plant that, immediately prior to that date, belonged to Group 2 (including any activity or plant previously in Group 1) is taken to belong to Group 5.

2) *An activity or plant is not taken to belong to Group 5 by virtue of sub-clause (1) if the conditions of the licence for the activity or plant state that it is taken to belong to Group 1 or 2.*
3) *An application for the variation of the conditions of a licence for the purpose of including a statement referred to in sub-clause (2) must be made:*
   a) *in the case of an application for the first such variation, on or before 1 January 2011, and*
   b) *in the case of an application for any subsequent variation, no later than 12 months before the date on which the current variation expires pursuant to sub-clause (4).*
4) *A variation of the conditions of a licence under this clause expires at the end of 5 years after the date on which notice of the variation is given to the holder of the licence under section 58 of the Act.*

Delta has sought exemption from the Group 5 NOx limit of 800 mg/Nm^3 in accordance with sub-clause 3 and 4 above.

In June 2011, Delta received formal notification granting an exemption to Group 5 emission limits for oxides of nitrogen (NOx) until 1 January 2017, but with a more stringent EPL NOx emission limit of 1,500 mg/m3 compared with the Group 2 NOx emission limit of 2,500 mg/m^3. Delta successfully re-applied for the exemption to be extended for a further 5 years to 1 January 2022 in 2015.

3.3 Vales Point Environment Protection Licence (EPL No. 761)

The main regulated air emission sources associated with the operation of Vales Point and associated infrastructure are the boiler stack (Unit 5 and Unit 6), including sulfur oxides (SO_X), nitrogen oxides (NO_X) and particulate matter (PM).

As required by EPL No. 761 stack emissions testing for a range of pollutants is required continuously for NO_X, and SO_X, with solid particulates, fluoride, VOCs and a range of trace elements required on an annual basis.

With respect to NO_X the 100th percentile concentration limit is 1500 mg/Nm^3. This limit has a 1-hour average time and, as such the continuous emission monitoring system (CEMS), which for EPL compliance purposes reports NO_X concentrations on an hourly basis, needs to demonstrate compliance with this limit for every hour in the year. There is also a 99th percentile concentration limit of 1100 mg/Nm^3.

A full list of EPL No. 761 conditions relating to air emissions are set out in **Appendix B**.

4. Review of Existing Studies

4.1 Overview

This section of the report provides summary of existing reports relating to Vales Point emissions regulation, management and control. The full review is included in **Appendix C**. The findings from these reports (refer Table 4-1) were summarised in 2017. This report provides a status update in 2021, where the findings were implemented at VPPS:

4.2 Relevance to NO_x Pollution Reduction Study

Table 4-1 provides a summary of the main findings from the Vales Point technical papers provided for review.

Table 4-1 : Main Findings from the technical paper review.

Report Findings	2021 status / Jacobs comments
'Vales Point Power Station Units 5 and 6 Combustion Analysis Report' – Robert Ironside & Associates, April 2015 General performance observations relating to combustion (and NOx) on the Vales Point Boilers are: i. The higher oxides of nitrogen (NOx) on Unit 6 compared with Unit 5, occurred due to wide range burner tips; ii. Low reheat steam temperatures observed on both units; iii. Intermittent high fabric filter inlet temperatures, due to high ambient temps; iv. Intermittent uneven flue gas oxygen levels between A & B furnaces of each unit; v. Intermittent mill classifier blockages on both units.	Unit 6 wide range burner tips on replaced with conventional tips (April 2021) reducing U6 NOx. Emissions are now comparable on both units Overhaul of Unit 6 has evened out A and B side oxygen and NOx A screening plant has reduced plastic contamination of coal, which had previously caused Mill classifier blockages Secondary air damper actuators are being overhauled/replaced on Unit 6, with Unit 5 to be done following completion of Unit 6. Both Units expected to have been completed by Nov/Dec 2021.
Improving Combustion Performance at Older Coal Fired Plant' report – Alstom, 2002 Inconsistency of pulveriser performance and unequal distribution of air and coal between individual corners occurs at Vales Point, often as a result of coal contaminants getting trapped in the pulverised fuel (PF) system. Poor PF fineness will contribute to less stable combustion and high CID under these conditions.	Delta now has a procedure in place to detect PF line blockages using thermal imaging technology. A screening plant at the coal mine has reduced contamination to a "rare occurrence".

'Vales Point Power Station Unit 6 NOx & Unburnt Carbon Tuning (Post Wide Range Tip Installation)' – Alstom, September 2013 Wide Range burner tips were fitted to VP6 in 2012 by Alstom which: i. improved CID - decreased by 50% and reportedly improved turndown as promoted by the OEM, (but turndown was not demonstrated) ii. increased NOx emissions of 300 ppm to 350 ppm (contrary to supplier indications of minimal impact on NOx) Combustion tuning was recommended by Alstom to provide reduction in NOx.	U6 wide range burners replaced with conventional design and 2021 overhaul has reduced NOx emissions substantially The combustion tuning was completed to little effect
'V500781 Burner Upgrade Financial Evaluation White Paper' – Delta, March 2014 • The reduced burner primary airflow achieved by increasing the mill fuel/air ratio from 1.0 to 1.2 has resulted in a reduction in NOx generation (insufficient data to quantify reduction) and appears to have resulted in an improvement in hot reheat steam temperature with no adverse effects observed on any other parameter.	Delta have advised that tests were conducted between October 2015 and February 2016 with reportedly no significant improvement in NOx. No adverse effect were noted in the short term, however subsequent experience indicates a 1.2 fuel primary air ratio giving poor performance with wet coal and roping of coal transport.
• Operation of the boilers with increased burner tilt angle (upwards) increased both NOx and hot reheat steam temperature. The Delta paper recommends that the tilt angle be limited in range from a low of -5º to a high of 12º.	Delta operate -3° to +15° tilt which meets the report recommendation
• Delta changed windbox to furnace differential pressure on Unit 6 to 1.2kPa on Unit 6(to match Unit 5)	Ironside reports a NOx improvement
• On-line CO analysers in the flue gas ducts upstream of the air heater should be considered, with a view to using measured CO to detect combustion problems and provide a balance between NOx emissions and boiler efficiency.	The flue gas oxygen (excess air) has been reduced from 3.5% to 3.2% as part of DCS works. Delta report no further gains to be made in this area
• Plastic contamination of the coal causes blockages of the mills, riffle boxes and fuel pipes, as the plastic melts and conglomerates under the hot primary air. Some plastic in coal is unavoidable, but while the management of plastic by the coal suppliers has improved, there is room to improve further. Delta reinforces the requirement of a clean coal supply with the mines. The mines have instigated programs to reduce mine contamination and a screening plant for the Mandalong coal supply has been installed. Delta also has a procedure in place to detect PF line blockages using innovative thermal imaging technology.	Delta reports that while contamination may occur with coal supplies, it is significantly reduced due to the installation of the screening plant.

Reduction via overfire air - Feasibility of use of unused sootblower ports in boiler windbox' – Aurecon, July 2015 There are 22 unused sootblower openings above the top burner level could be used for inserting Over Fire Air, but it is only 1.9% of secondary air flow. US research (EPRI) using modelling coal fired furnaces was extrapolated, and Aurecon report up to 10% NOx reduction could be achieved.	The small amount of airflow which could be introduced as overfire air and, the location of the ports in a short furnace would not result in a material difference in NOx .
Incorrect positioning of the 96 secondary air dampers can occur, upsetting combustion. Routine stroking of the dampers was recommended.	Delta advise they routinely stroke dampers. Secondary air damper actuators are being overhauled/replaced as necessary to improve control. This is almost completed for Unit 6, and will be completed on Unit 5 by Nov / Dec 2021
Vales Point NOx Reduction, Draft Secondary Air Tuning Test Report – Aurecon December 2010 A reduction in NOx emissions of almost 10% was achievable with a reduction in furnace flue gas O_2 from 3.3% down to 2.7%. However, this increased the carbon in ash to between 3.7 and 4.1% and reduced boiler efficiency.	NOx reduction needs to be balanced with the carbon in ash limit for cement (3.5-4.5%). High carbon in ash would result in flyash not being recycled, and materially increases fuel costs.

5. Review of Vales Point Operational Data

5.1 Overview

The average NOx concentration emissions for each Unit are presented in **Table 5-1** below, which provides an update from the 2017 report.

Table 5-1 : NOx emissions update

	Jan 2015- Mar 2017	Mar-2017 – Aug 2021	
Unit 5 NOx emissions (mg/Nm^3)	613	609	
Unit 6 NOx emissions (mg/Nm^3)	889	532 (769	July 2021-Aug 2021 Mar 2017- Apr 2021)

The following observations are made:

- Unit 5 NOx emissions are stable
- Unit 6 NOx emissions have reduced substantially from 889 mg/Nm^3 to 532 mg/Nm^3 (45 days data). This reduction is largely from retrofit with conventional burner tips. There have been only 3 minor events above 800 mg/Nm^3 during this period.
- The lower NOx emissions of Unit 6 (532 mg/Nm^3) are due to its recent return from a major maintenance outage, compared with Unit 5 (609 mg/Nm^3).

Unit 6 also had a IP turbine upgrade which has reduced the unit heat rate by 1.9%. The reduced heat rate (the ratio of energy in fuel per unit of electricity produced), corresponds to reduced fuel consumption, and reduced NOx mass emissions by 1.9% (refer **Section 5.4** for forecast NOx mass reductions).

A more comprehensive summary of the CEMS data analysed is provided in **Appendix D.**

5.2 CEMS Data Analysis

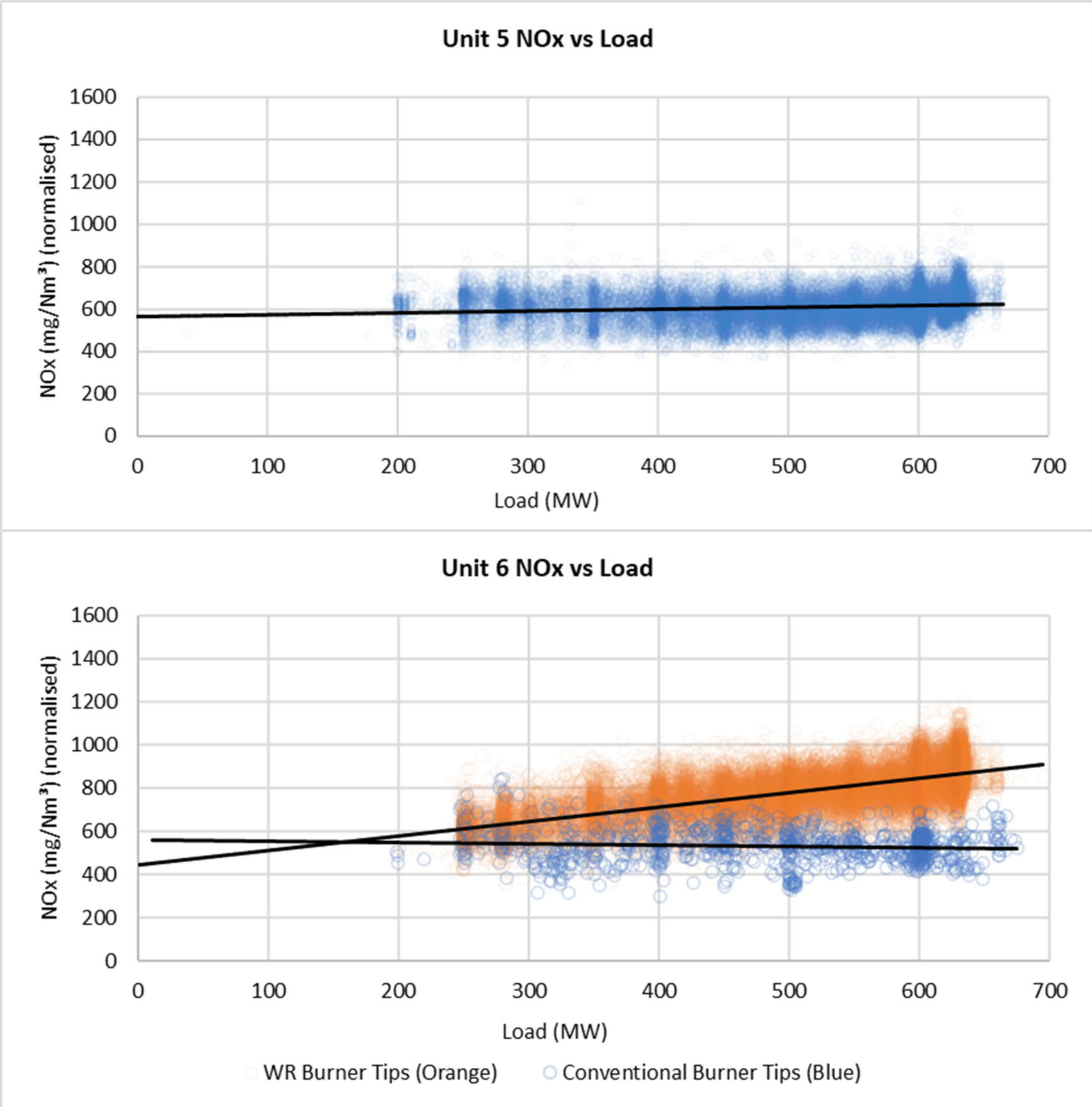
The NOx emissions from Vales Point are measured by a Continuous Emissions Monitoring System (CEMS), which records emissions to air and reports on an hourly basis. The sampling points are located in the horizontal ducts immediately prior to the stack penetration. NOx data was analysed from Jan 2015 to August 2021, (refer **Figure 5-1**):

- Unit 5 NOx — Average 607 mg/Nm^3 @7% O_2 — (99.6% < 800 mg/Nm^3; and
- Unit 6 NOx post July 2021 — Average 532 mg/Nm^3 @7% O_2 — (99.7% < 800 mg/Nm^3)

The following observations are made :

- Unit 5 & 6 NOx emissions are stable irrespective of load
- Wide range burners on Unit 6, now removed, increased NOx emissions with load

Figure 5-1: NOx levels and Operating Loads sampling period 2017-2021



A more detailed analysis of the 2017-2021 period is shown in **Table 5-2** and **Table 5-3** below. Unit 6 data is separately reported for January-April (wide range burners) and for July (conventional burners) for comparison.

Table 5-2 : Summary of dataset over the period 2017-2021

	Unit	Operating (days)	Average Load (MW)	Average NOx (mg/Nm^3)	Maximum NOx (mg/Nm^3)
2017	Unit 5	260	512	591	1075
	Unit 6	259	498	786	1184
2018	Unit 5	261	517	621	1018
	Unit 6	311	540	840	1507
2019	Unit 5	313	514	624	932
	Unit 6	308	523	791	1149
2020	Unit 5	292	470	611	1245
	Unit 6	312	490	741	1262
2021	Unit 5	213	485	589	922
	Unit 6 pre April	94	416	693	1070
	Unit 6 post July	45	473	532	976

Table 5-3 : Summary of data from the period 2017-2021 within various emission limits

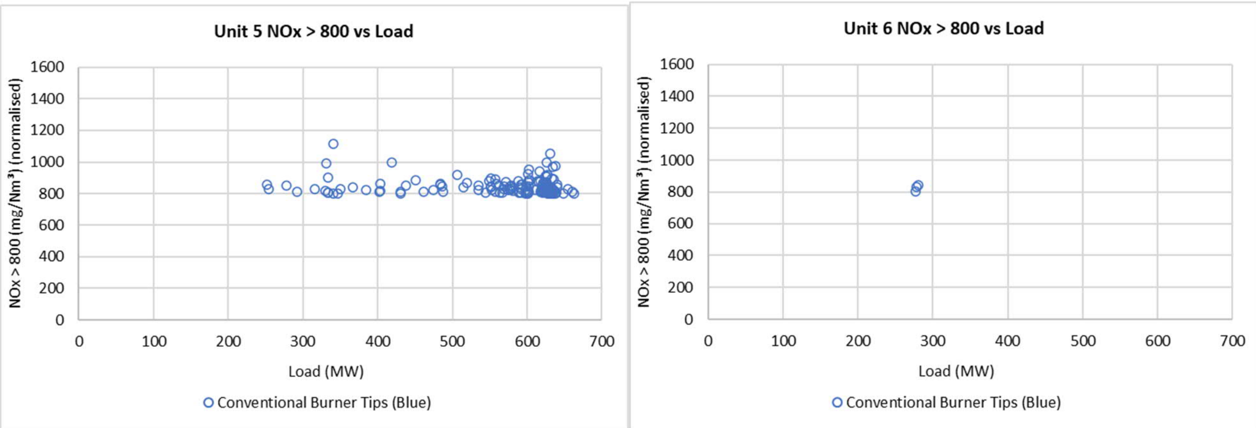
	Unit	NOx < 800mg/Nm3	NOx < 1100mg/Nm3	NOx < 1500mg/Nm3
2017	Unit 5	99.8%	100.0%	100.0%
	Unit 6	52%	100.0%	100.0%
2018	Unit 5	99%	100.0%	100.0%
	Unit 6	33%	99.6%	100.0%
2019	Unit 5	99%	100.0%	100.0%
	Unit 6	50%	100.0%	100.0%
2020	Unit 5	99%	100.0%	100.0%
	Unit 6	72%	100.0%	100.0%
2021	Unit 5	100.0%	100.0%	100.0%
	Unit 6	85% pre April 99.7% post July	100.0%	100.0%

Most of the Vales Point NOx emissions fall below 800 mg/Nm^3, and all were consistently below the current 99th and 100th percentile limits of 1100 and 1500 mg/Nm^3 (with the exception of Unit 6 with the former wide range burners). The Unit 6 low average emissions post July 2021 are consistent with Unit 5 since the change in burner tips.

5.2.1 NOx measurements > 800 mg/Nm³

Measured NOx levels above 800 mg/Nm³ were examined, to observe any trends (refer **Figure 5-2)** throughout the last five years (Unit 5), and since overhaul (Unit 6). The NOx levels above 800 mg/Nm³ occur at all loads, are random one-off events, and are likely from upset conditions, or mill changeovers.

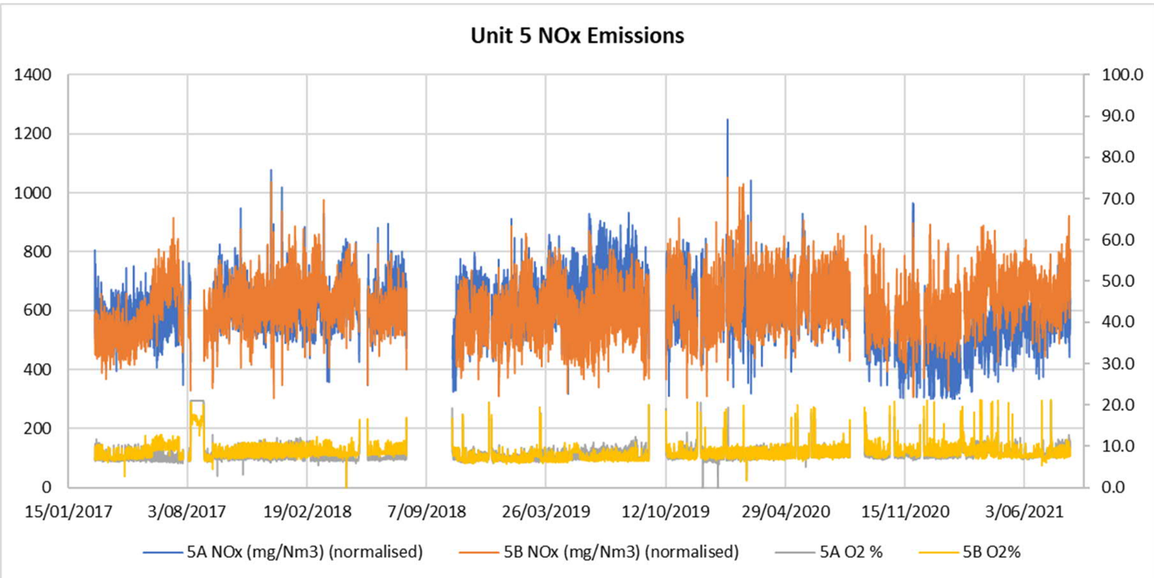
Figure 5-2 NOx > 800 mg/Nm³ versus Unit load 2017-2021



5.2.2 Unit 5 NOx

Unit 5 NOx emissions show a slight increase over time, and generally drop after an overhaul. Furnace A emissions were higher in some periods and Furnace B emissions in others. The work done during outages appears to impact this (refer **Figure 5-3**).

Figure 5-3: Unit 5 Furnace A & B NOx Readings period 2017-April 2021



5.2.3 Unit 6 NOx

NOx emissions were significantly reduced on Unit 6 with the change to conventional burner tips, and a major overhaul in mid 2021 (refer **Figure 5-4**). Since then there have been only 3 excursions above 800mg/Nm³ (refer **Figure 5-5)**. NOx emissions are consistent between 6A and 6B furnaces. The good emissions performance following this upgrade should be noted.

Figure 5-4: Unit 6 Furnace A & B NOx Readings 2017-2021

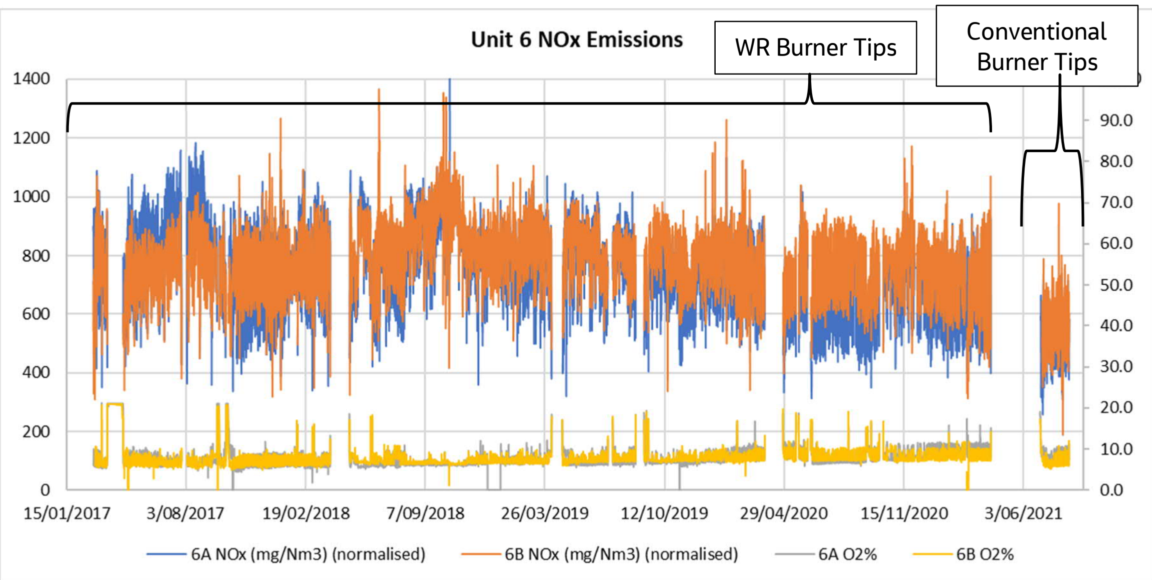
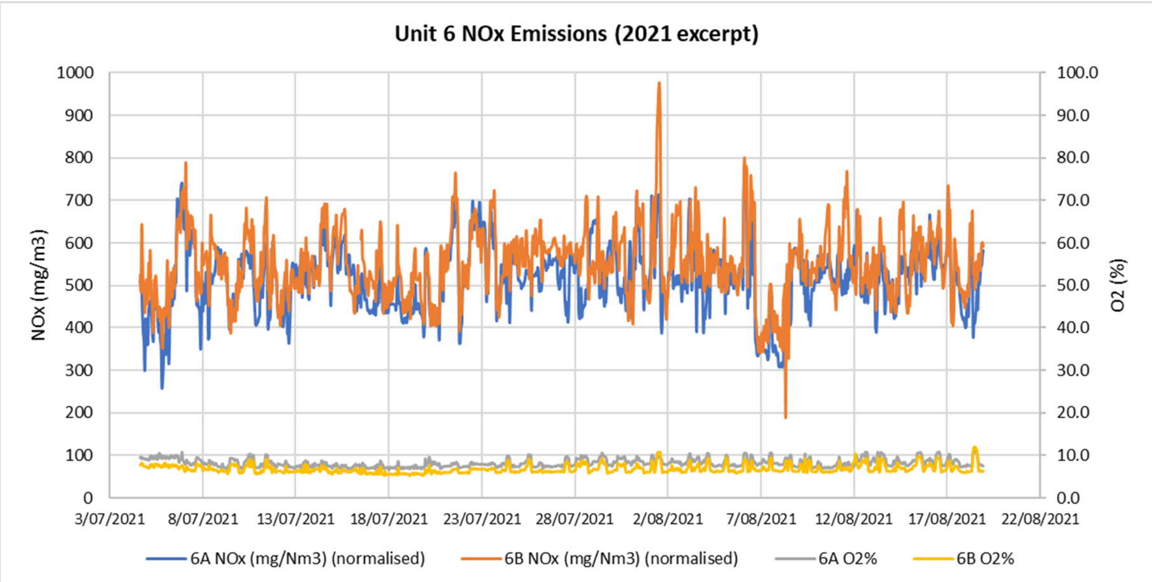


Figure 5-5: Unit 6 NOx 2021



5.2.4 Variations between Furnaces A and B

Unit 6 NOx emissions from Furnaces A and B are similar after the recent major overhaul while Unit 5 shows some differences between Furnaces A and B, attributable to:

i. Instrumentation, where drift in calibration may occur over time

ii. Wear in mechanical parts, and in the combustion system, leading to differences in fuel / air ratios. (The burners are replaced every 4 years and the mills are regularly maintained to ensure Unit capacity)

iii. Time since last overhaul for both the boiler and the mills (which are overhauled more regularly)

iv. Coal contamination impacting mill performance (which has largely been resolved)

These differences are to a large extent unavoidable, as they are inherent in the operation of solid fuel combustion plant. Wear and tear may result in minor performance degradation over time, which is usually recovered at major overhaul. The Unit overhaul cycle is major (4 yearly) and minor (2 yearly). The overhauls for Unit 5 and Unit 6 are staggered to avoid overlap, such that only one major or minor overhaul is completed each year. As a result there will be some difference in performance between the Units. However, there is potential to reduce the differences between the A and B passes on Unit 5. These differences might be rectified in the next maintenance cycle.

Several studies have recommended that combustion optimisation be conducted so that the conditions in and emissions from Furnaces A and B are better aligned. Ironside completed combustion tuning in 2015, however the tuning had little effect.

Delta Electricity has advised that investigations are ongoing in this area. Key actions are as follows:

- O_2 probes are calibrated or replaced during every outage
- Defects with burner tilting (thermal distortion/jamming or clinker buildup) impact combustion performance. Delta is investigating the best method for repairing the burner linkages as access inside the furnace is difficult, requiring a 10-day outage and furnace scaffolding. This length of outage can only be completed during an overhaul.
- Testing was completed in July 2021 to validate the CEMS readings against a portable analyser. Results are being analysed
- Delta are in the process of repairing / replacing mill aspirating air valves adjacent to the riffle boxes to allow routine particle size sampling from pulverised fuel pipes. This will enable routine PF sampling to ensure optimum PF grind.

5.3 Coal Analysis

The coal for Vales Point power station, up to the end of June 2022, is primarily of equal proportions from Mandalong, and Chain Valley Mines. For the period from July 2022 to end of life, the coal is to be supplied predominately from Chain Valley (>50%) with smaller volumes from Mandalong, Invincible, and Airly. However, future contracts may be negotiated with alternative suppliers subject to market availability and conditions. A rail loop is available for receiving deliveries of coal from Lithgow or the Hunter Valley. (The amount of coal which can be delivered by rail is limited by the train paths available from Sydney Trains.)

The coal fired is typically low sulphur, low moisture, high ash, high fixed carbon, and low volatiles (refer **Table 5-4** below). The nitrogen content is within the typical 1-2% range for Australian coals.

The characteristics of the coal which specifically affect NOx emissions are:

- Fixed Carbon: A high fixed carbon increases the burnout time for the coal, and results in high carbon in dust, and requires a higher level of excess air in the furnace to promote combustion leading to higher NOx.
- Hardgrove Grindability Index (HGI): The low HGI means the coal mills need to work harder to achieve the required level of fineness. (A lower index requires additional work by the mills). In practice, as the grind ability of the mills is fixed, a lower HGI will mean a coarser fraction of coal is transported to the furnace, increasing burnout time.
- Volatile Matter: As a general rule, low volatile matter requires additional air for flame stability.

Table 5-4 Coal Analysis

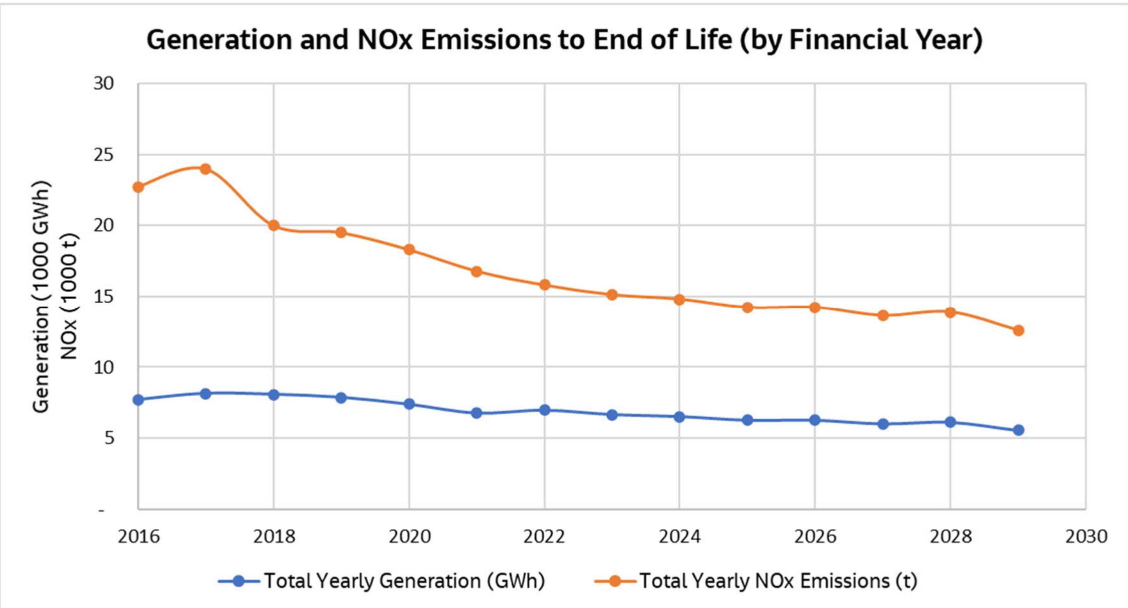
Proximate Analysis	Units & Basis	Design	April 2017	June 2021 - June 2022 Average	July 2022 - July 2023 Average
Total H_2O	% ar	8	7.6	8.15	7.84
Ash	% ar	18.7	21.5	23.86	23.47
Volatile Matter	% ar	26.5	26.3	24.2	25.03
Fixed Carbon	% ar	46.41	44.6	43.79	43.69
Sulfur	% ar	0.39	0.32	0.34	0.37
Calorific Value	kJ/kg ar	25,300	23,720	22,766	23,032
Hardgrove Grindability Index	HGI	47			
Ultimate Analysis					
C	% ar	60.99	58.35	57.02	57.32
H	% ar	3.88	3.64	3.63	3.69
N	% ar	1.25	1.26	1.12	1.21
Ash	% ar	18.7	19.8	23.8	23.42
S	% ar	0.29	0.31	0.34	0.37
O	% ar	6.89	7.30	5.66	5.86
H_2O	% ar	8	7.8	8.1	7.84

The quality and higher heating value (~23MJ/kg) between the delivered coal from 2017 to 2021 and to the end of life in June 2029 is very similar, even with the change in the coal colliers. The carbon content remains very similar and there should be no increase in NOx due to changes in coals fired.

5.4 Generation and NOx emissions to End of Station Life

There is predicted to be a decrease in the NOx mass emissions from Vales Point Power Station from present to the predicted closure in 2029, due to the forecast reducing generation from the station. The increased penetration of renewables in the National Electricity Market is reducing the capacity factor of coal fired power stations. This has led Vales Point to steadily decrease their production forecasts for coming years. **Figure 5-6** below shows the current forecasts for generation from the station (GWh) as well as the NOx emissions that this is predicted to create (t).

Figure 5-6 : Forecast Generation and NOx Emissions to End of Life



A NOx intensity of 2.27kg of NOx emissions per MWh of energy sent out from Vales Point was used to predict emissions for 2022-2029. This equates to an average NOx emission concentration of approximately 600mg/Nm^3, (conservative allowing for minor degradation over time). A NOx intensity of 2.48kg/MWh was used for the period 2018-2021 and 2.95kg/MWh for 2016-2017. This reflects the higher emissions from VPPS in past years with the wide-range burner tips installed on Unit 6, and prior to the IP turbine upgrade (1.9% heat rate improvement).

5.5 Summary Findings

Vales Point NOx emissions largely fall below 800 mg/Nm^3, and all were consistently below the current 99th and 100th percentile limits of 1100 and 1500 mg/Nm^3.

NOx exceedances of 800 mg/Nm^3 occur at different unit operating loads, and are random in nature (i.e. not able to be predicted and controlled).

Significant improvements have been made to the NOx emissions from Unit 6 by replacing the wide range burner tips with conventional tips in June 2021. The IP turbine upgrade also brought about a 2% reduction in NOx mass emissions commensurate with the heat rate improvement.

The data suggests that there are some limited combustion improvements which can be made to reduce NOx on Unit 5. We would recommend:

- Continue to investigate Unit 5 variation between furnaces 5 (it is likely this will be rectified with the next maintenance cycle) and continue conducting combustion optimisation (refer **Section 8.2**) to improve this where possible;

- Continue to monitor coal grind, and ensure equal coal and air distribution;

6. Literature Review

6.1 Overview

This section provides a review of international best practice measures to minimise NOx emissions from coal fired electricity generation.

The review focuses on the Unites States / Canada, Europe, and Asia, as these regions have a predominance of coal fired power stations and as a result of poorer air quality in these regions, have tightened emission control requirements over time. The review also focuses on NOx emissions, however other emissions may also be referenced for information.

6.2 United States / Canada

6.2.1 Regulatory / Policy Considerations

In 1970, the United States Congress passed the Clean Air Act (CAA). This law authorised the development of comprehensive federal and state regulations to limit emissions from both stationary and mobile sources. Four major regulatory programs effecting stationary sources were initiated:

- National Ambient Air Quality Standards (NAAQS);
- State Implementation Plans (SIPS);
- New Source Performance Standards (NSPS); and
- National Emissions Standards for Hazardous Air Pollutants (NESHAPS).

The CAA required the United States Environmental Protection Agency (U.S. EPA) to establish nationwide primary and secondary NAAQS for six criteria air pollutants. The primary standards set limits to protect public health and the secondary standards were set to protect public welfare. The six criteria pollutants were:

1) Total suspended particulate matter (PM), which was revised to PM_{10} in 1976,
2) Sulfur dioxide (SO_2),
3) Carbon monoxide (CO),
4) Hydrocarbons (deleted in 1983),
5) Nitrogen dioxide or NOx, and
6) Photochemical oxidants (changed to Ozone in 1979).

The standards were further revised to include:

- Lead in 1976, and
- $PM_{2.5}$ and 8-hr ozone established in 2004.

The U.S. EPA has promulgated several regulations to addresses primary and secondary NAAQS. The most recent regulations limiting air emissions from U.S. coal fired power plants are the Cross-State Air Pollution Rule and the Mercury and Air Toxic Standard (MATS) Rule.

On July 6, 2011, the U.S. EPA finalised the Cross-State Air Pollution Rule (CSAPR) [4]. CSAPR required 27 states in the eastern half of the U.S. to reduce power plant emissions of NOx, and in some cases SO_2, which contribute to ozone and fine particle ($PM_{2.5}$) pollution in other states. On September 7, 2016, the EPA finalised an update to the CSAPR by issuing the final CSAPR Update. Starting in May 2017, this rule aimed to reduce summertime NOx emissions from power plants in 22 states in the eastern U.S. The final rule provided

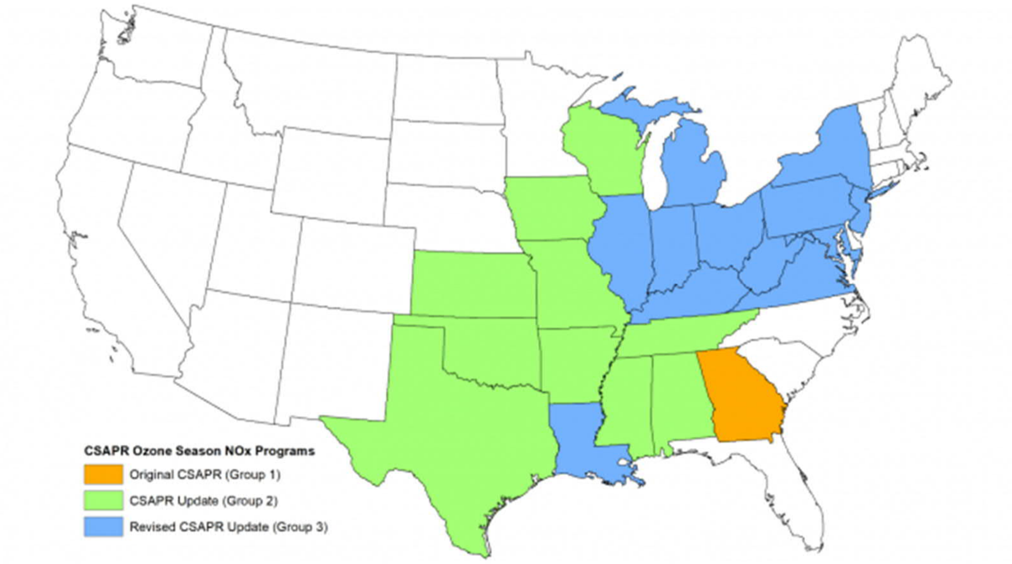
[4] https://www.epa.gov/csapr/overview-cross-state-air-pollution-rule-csapr accessed August 2021

emission allowance trading among affected emission sources, utilising an allowance market infrastructure based on existing allowance trading programs.

Allowance trading allows sources in cap and trade programs to adopt the most cost-effective strategy to reduce emissions. Utilities that reduce their emissions below the number of allowances they hold may trade allowances with other sources in their system, sell them to other sources on the open market or through EPA auctions, or bank them to cover emissions in future years.[5]

A 2019 ruling by the United States Court of Appeals remanded the 2016 CSAPR Update for failing to fully eliminate significant contribution of ozone to downwind states. For this reason, On March 15, 2021, EPA finalised the Revised Cross-State Air Pollution Rule (CSAPR) Update in order to resolve 21 states' outstanding interstate pollution transport obligations for the 2008 ozone National Ambient Air Quality Standards (NAAQS)[6]. Starting in the 2021 ozone season, this final rule will reduce emissions of nitrogen oxides (NOx) from power plants in 12 states. This rulemaking includes adjusting emission budgets for each state for each ozone season for 2021 through 2024 and requires affected states to participate in a new CSAPR NOx Ozone Season Group 3 Trading Program. Participation in the more stringent new program would replace the obligation to participate in the existing CSAPR NOx Ozone Season Group 2 Trading Program. [7] **Figure 6-1** shows the states effected by each update.

Figure 6-1 : Cross-State Air Pollution Rule Regions (epa.gov)



Other key provisions are designed to minimise pollution increases from growing numbers of motor vehicles, and from new or expanded industrial plants. The law calls for new stationary sources (e.g., power plants and factories) to use the best available technology, and allows less stringent standards for existing sources.

The New Source Performance Standards (NSPS) for fossil fuel-fired electric utility steam generating units are outlined in the Code of Federal Regulations under 40 CFR Part 60 Subpart Da. The limits for nitrogen oxides under this regulation are 210ng/J (0.76kg/MWh) for plants commissioned before 1997 and 88ng/J gross or 95ng/J net (0.31kg/MWh net, 0.34kg/MWh gross) for recently constructed plants (commissioned after 2011)[8].

[5] https://www.epa.gov/airmarkets/allowance-markets accessed August 2021
[6] https://www.epa.gov/csapr/revised-cross-state-air-pollution-rule-update accessed August 2021
[7] https://www.monitoringanalytics.com/Reports/Market_Messages/Messages/IMM_CSAPR_Ozone_Season_Changes_20210430.pdf accessed August 2021
[8] https://www.ecfr.gov/cgi-bin/text-idx?node=sp40.7.60.d_0a#se40.7.60_144da accessed August 2021

Canada's 'New source emission guidelines for thermal electricity generation' outlines the emissions limits for new coal fired power plants. In relation to NOx emissions, it states the following:

> *"The hourly mean rate of discharge of nitrogen oxides, expressed as NO_2, emitted into the ambient air from a new generating unit when determined over successive 720 hour rolling average periods should not exceed the emission rate of 0.69 kg/MWh net energy output."*[9]

Two final regulations were published in the Canada Gazette, Part II, on December 12, 2018. The effect of these is that the phase-out of conventional coal-fired electricity units is accelerated and thermal generators are required to meet the performance standard of 420 tCO_2/GWh at the end of their useful life or by December 31, 2029, whichever is sooner. The amendments to the coal regulations are expected to result in cumulative reductions 206 kt of nitrous oxides (NOx) between 2019 and 2055.[10]

6.2.2 Combustion Modifications

6.2.2.1 LNB / OFA / NN

Low NOx Burners (LNB), Overfire Air (OFA), and Neural Networks (NN) can provide a moderate level of NOx reduction. LNB and OFA are common technologies used in U.S. coal fired power plants, one 2021 survey of US generators by the EPA showed that almost 75% of coal fired plants had low NOx burners[11]. In contrast, NN have limited installations with varying results. However, the MATS rule has forced some utilities to consider NN[12]. Often these technologies must be combined with post-combustion control methods to meet the current regulations.

An example of the use of NN coupled with OFA is at the Ameren Labadie plant in Missouri which uses Powder River Basin coal. It has a 600 MW tangentially fired boiler with a single furnace. The boiler is equipped with low NOx burners and over-fire air. Use of the NN with OFA technology brought about NOx reductions of over 30 per cent[13].

6.2.2.2 Tangential firing / ROFA

Tangential firing is the combustion technology supplied by Combustion Engineering (now GE), and in some Foster Wheeler boilers. The burners are located at the corners of the furnace, and directed to induce a rotating swirl flow in the furnace. The result is better mixing of the fuel and air, marginally reducing peak flame temperatures which leads to less thermal NOx production. One third of coal generators in the US in 2021 used tangential firing[11].

Rotating Opposed Fire Air (ROFA®) is a patented design by Nalco Mobotec. The furnace gas volume is rotated via an asymmetric boosted over-fire air system. The induced rotation and turbulence prevent laminar flow, which results in better temperature distribution and better combustion. With the ROFA technique, excess air can be reduced without increasing CO or other unwanted substances. The technology has demonstrated some NOx reduction.

Various boiler suppliers have their own low NOx firing systems. The predicted NOx performance of various GE combustion systems is shown in the **Figure 6-2**.

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[9] https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/guidelines-objectives-codes-practice/new-source-emission-guidelines-thermal.html#toc3 accessed August 2021

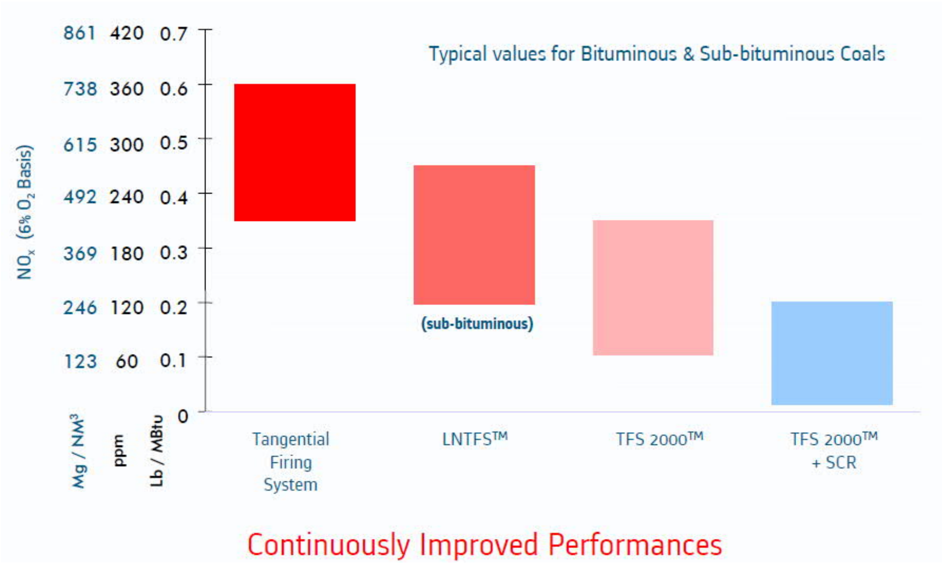
[10] https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/technical-backgrounder-regulations-2018.html accessed August 2021

[11] National Electric Energy Data System (NEEDS) v6, 343 LNB, 160 tangential firing, total 480 active coal-fired steam generators

[12] http://www.powermag.com/using-neural-network-combustion-optimization-for-mats-compliance/?pagenum=1 accessed August 2021.

[13] Website article "Neural Networks prove effective at NOx reduction, May 2000, 'http://www.modernpowersystems.com/features/featureneural-networks-prove-effective-at-nox-reduction/', accessed August 2021

Figure 6-2 : Predicted NOx Performance



6.2.3 Post-Combustion Capture

6.2.3.1 Selective Non-Catalytic Reduction (SNCR)

The SNCR process requires injection of either ammonia into the flue gas within a temperature window of 870-1100°C to reduce NOx to nitrogen and water. Typically, 30-50% NOx removal efficiencies can be achieved with SNCR technology. The 2021 US EPA survey found that less than 20% of coal fired generators had SNCR technology installed (88 of 480 total, National Electric Energy Data System - NEEDS).

6.2.3.2 ROTAMIX

ROTAMIX® is another Nalco Mobotec patented technique for rotary mixing of chemicals in the boiler. The system is used to provide better ammonia or urea mixing than traditional SNCR systems. When the ROTAMIX system is combined with ROFA, significant reduction in NOx can be achieved with a minimum amount of ammonia slip. One study suggested that a NOx reduction of over 80% can be achieved with the ROFA/ROTAMIX combination[14], although this is not a widely used technology so average NOx reduction percentages are hard to identify.

6.2.3.3 Selective Catalytic Reduction (SCR)

SCR is a capital-intensive, post-combustion technology that uses catalyst elements installed in the flue gas stream to promote the NOx reduction reaction. An SCR can reduce the NOx in the flue by 80-90%. In 2021 almost 50% of the generating coal-fired units in the US had SCR installed (226 units, US EPA), however this percentage appears high due to other coal units having retired from ratcheting down of emission limits and low gas prices. The three basic SCR configurations at coal-fired units in the U.S. are: high-dust-hot side, low-dust-hot side, and low-dust-cold side. The preferred option is a function of:

- The anticipated fly ash effects on catalyst operation/life; and
- Existing equipment arrangement.

Ammonia is used as the reducing agent and is injected into the flue gas upstream of the catalyst within a temperature window of 290-415°C depending on the fuel characteristics and sulfur content.

[14] http://www.idc-online.com/technical_references/pdfs/chemical_engineering/rofa_rotamix_at_vermilion.pdf

By-products of the SCR reaction are nitrogen, water, and small amounts of SO_3. Discharged flue gas and fly ash will also contain low concentrations of ammonia that has slipped past the catalyst. Ammonia slip in the flue gas is a specified performance constraint usually limited to no more than 2-5 ppm. The ammonia can be supplied from several different sources:

- Anhydrous ammonia,
- Aqueous ammonia, or
- Urea hydrolyzed as needed to supply ammonia.

6.2.4 Summary

North America predominantly uses Low NOx burners (most units), with about half using SCR or SNCR for further NOx reduction. The advent of stricter emissions standards coupled with the availability of historically cheap natural gas has seen many utilities switch to gas fired based load generation to avoid costly retrofits for coal plant emissions upgrades.

6.3 Europe

6.3.1 Regulatory / Policy Considerations

Coal-fired energy generation currently accounts for approximately13% of all electricity production in the EU[15]. Coal-fired plants are governed by stringent national and European legislation to minimise emissions including sulfur dioxide (SO_2), oxides of nitrogen (NOx), and particulate matter.

6.3.1.1 Industrial Emission Directive (Directive 2010/75/EU)

Table 6-1 presents the emission limit values for SO_2, NOx and PM for coal-fired combustion plants as per Annex V Part 1 of Directive 2010/75/EU. (Note these emissions concentrations in mg/Nm^3 are not directly comparable to VPPS emissions as the EU directive corrects to 6% O_2, rather than 7% O_2).

Table 6-1 Emission limit values for SO2, NOx and particulate matter for coal-fired combustion plants

Total rated thermal input (MW)	Coal and lignite and other solid fuels (mg/Nm^3, 6% O_2)		
	SO_2*	NOx**	Dust (particulate matter)
50 – 100	400	300	30
100 – 300	250	200	25
>300	200	200	20

Notes:

*For SO_2, Annex V, Part 1 of Directive 2010/75/EU states an emission limit value of 800 mg/Nm^3 for those combustion plants which were granted a permit before 27 November 2002 or the operators of which had submitted a complete application for a permit before the date, provide that the plant was put into operation no later than 27 November 2003, and which do not operate more than 1,500 operating hours per year as a rolling average over a period of 5 years.

** For NOx, Annex V, Part 1 of Directive 2010/75/EU states an emission limit of 450 mg/Nm^3 for those combustion plants with a total thermal input not exceeding 500 MW which were granted a permit before 27 November 2002 or the operators of which had submitted a complete application for a permit before the date, provide that the plant was put into operation no later than 27 November 2003, and which do not operate more than 1,500 operating hours per year as a rolling average over a period of 5 yrs.

[15] EMBER, https://ember-climate.org/project/eu-power-sector-2020/, Accessed August 2021

6.3.2 Control of NO_x

The "Additional guidance for Combustion Activities" (EPR 1.0.1)[16], indicates Best Available Technology for point source emissions to air:

1) Control emissions of NOx by a combination of the following, as applicable:
   - Combustion control systems;
   - Combustion temperature reduction;
   - Low NOx burners
   - Over fire air (OFA);
   - Flue/exhaust gas recycling;
   - Re-burn
   - Selective catalytic reduction (SCR); and
   - Selective non-catalytic reduction (SNCR)
2) Use low NOx burners for a coal fired plant.
3) Use OFA or equivalent for existing coal-fired plant above 100 MWth.
4) Where air quality standards or other environmental standards must be met, you must use SCR or SNCR for smaller plant (<100 MW).
5) For new coal / oil-fired plant above 100MW, use SCR or primary measures to achieve equivalent NOx levels.
6) Only combustion optimisation and SCR are feasible on >500MW PF plant firing low volatile coal. In these cases you need SCR for new plant. You need a site specific assessment for existing plant.

BAT for the reduction of NO_X emissions and the associated limits for various fuels are provided in **Table 6-3**.

Table 6-2 BAT for the reduction of NO_X from coal-and lignite-fired combustion plants[17]

Capacity (MW thermal)	NOx emission level associated with BAT (mg/Nm^3) (yearly ave)		BAT options to reach these levels
	New plants	Existing plants (1)	
< 100	100-150	100-270	CO, PT, SNCR if operated >1500h/year
100 – 300	50-100	100-180	CO, PT, SNCR if operated >1500h/year, SCR if operated >500h/year
≥ 300, FBC boiler combusting coal and/or lignite and lignite-fired PC boiler	50-85	< 85-150 (2) (3)	CO, PT, SNCR if operated >1500h/year, SCR
≥ 300, coal-fired PC boiler	65-85	65-150	CO, PT, SNCR if operated >1500h/year, SCR

Notes: (1) These BAT-AELs do not apply to plants operated < 1500 h/yr.

(2) The lower end of the range is considered achievable when using SCR.

(3) The higher end of the range is 175 mg/Nm3 for FBC boilers put into operation no later than 7 January 2014 and for lignite-fired PC boilers.

CO: Combustion Optimisation

PT: Combination of other primary techniques e.g. air staging, fuel staging, FGR, LNB

[16] Withdrawn in 2018 and replaced with several new documents; however, this summary is still relevant as it outlines BAT techniques

[17] Table adapted from Integrated Pollution Prevention and Control Reference Document on Best Available Techniques for Large Combustion Plants, 2017, BAT 20 and Table 10.3, page 801

6.3.3 Summary

Table 6-3 summarises the technological and operational practices for the management of emissions from a coal-fired plant in the UK/Europe.

Table 6-3 Emissions management practice summary, UK/Europe

Regulatory/Policy measures	Emissions technological controls	Estimated costs	Operational practices	Comments
Industrial Emission Directive (Directive 2010/75/EU) Schedule 1 of the Environmental Permitting (Amendment) Regulations 2013 (UK only)	Low NOx burners	Not available	Air/fuel staging; Flue gas recirculation; Reburn; Over fire air (OFA); and Combustion temp reduction.	BAT for NOx control dependent on combustion technique, station capacity and whether new or existing. Higher costs apply when retrofitting existing plant, rather than new plant being designed and constructed to accommodate NOx controls, but no specific cost information was identified to quantify differences.
	Selective catalytic reduction (SCR)	Plant specific		
	Selective non-catalytic reduction (SNCR)	Plant specific		

6.4 Asia

6.4.1 Regulatory / Policy Considerations

The Equator Principles and IFC Performance Standards are applied to financing of new power developments and the refinancing of refurbishments of existing power plants. They require the coal fired power plants to be constructed and operated to 'good international industrial practice' and that the control technologies for air emissions can be benchmarked against those applied in developed countries.

6.4.1.1 China

In 1991, China began imposing progressively lower limits on emission concentrations at power plants. The current standards (GB13223-2011) went into effect on July 1, 2014, limiting SO_2, NO_X and PM emissions from Chinese coal-fired power plants to 100, 100 and 30 mg/m^3, respectively.

Nevertheless, in 2014, China proposed Ultra Low Emission (ULE) standards at 35, 50 and 10 mg/m^3 for SO_2, NO_X and PM, respectively. These stricter ULE standards cover the full fleet of existing and future coal-fired power-generating units, requiring that at least 580 GW installed capacity of existing units meet the ULE standards by 2020 (approximately half the installed capacity), and that at least 80% of capacity (including both pre-existing and new units) achieve compliance by 2030. Many Chinese plants now meet these ULE standards, refer to **Section 7.3** for recent emissions levels.

As a result of the strict standards implemented, monthly emission factors of Chinese coal-fired units declined between 2014 and 2017 by 75.33%, 76.03% and 83.31% for SO2, NOX and PM, respectively[18].

6.4.1.2 Japan

The Ministry of the Environment of Japan, formed in 2001, is responsible for establishing and implementing environmental policy, regulations on air pollution control, monitoring and other environmental aspects. Air pollution legislation is set out in the "Air Pollution Control Law", enacted in 1968 and amended various times

[18] https://discovery.ucl.ac.uk/id/eprint/10084916/1/Substantial%20emission%20reductions%20from%20Chinese%20power%20plants%20after%20the%20introduction%20of%20ultra-low%20emissions%20standards.pdf

since then. The latest amendment is 10 April 1998. Within these laws, regulatory measures for air pollutants from industry, relevant to the coal-fired power generation industry, is set out in the following forms:

- Emission/discharge standard that limits the amount of flue gas emission;
- Total amount of air pollutant emitted; and
- Ambient air quality standard for various pollutants in ambient air

The Air Pollution Control Act allows individual prefectures to set their own emission standards for soot, dust, and harmful substances, which are often more stringent than those set by the national government. The national legislation which affects NOx emissions from coal fired boilers are set out in **Table 6-4**[19].

Table 6-4: National emission standards, Japan

Pollutant	Specification	Capacity, Nm^3/hr	Emission standard, mg/Nm^3
NOx (existing plants)	Heating area: 10 m^2 or above	≥ 700,000 ≥ 40,000 and < 700,000 < 40,000	410 (200ppm) 512 (250ppm) 615 (300ppm)

6.4.1.3 India

The Indian Central Pollution Control Board sets national ambient air quality standards under the Air (Prevention and Control of Pollution) Act, which was enacted in 1981 and amended in 1987 to provide for the prevention, control and abatement of air pollution in India. The Environment (Protection) Act was enacted in 1986 with the objective of providing for the protection and improvement of the environment. These acts did not set ambitious limits and NOx emissions from thermal power plants increased by over 97% between 1996 and 2010[20].

In December 2015, the Ministry of Environment, Forest and Climate Change introduced regulations for coal-fired power plants, shown in the table below. They announced that implementation of emission control systems (ECSs) would be required within 2 years of the announcement. This deadline has since been pushed back, allowing power stations until 2022 to implement these measures. Power stations in national capital region were however required to comply with the revised norms by December 2019[21]

Table 6-5 Indian Emissions Standard for NOx and number of units impacted[22]

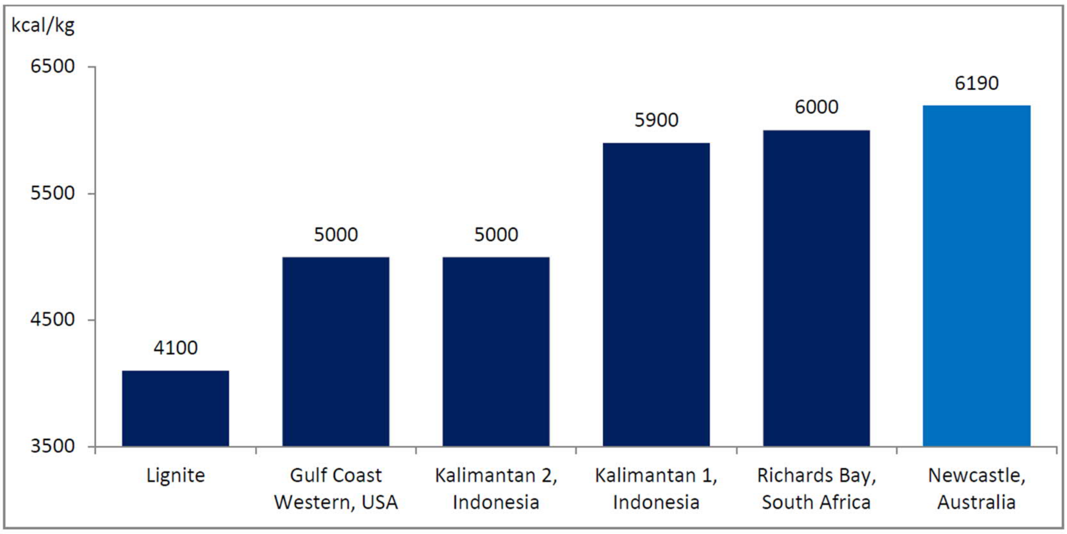
Capacity (Nm3/hr)	NOx Emissions Standard (mg/Nm^3)	Units impacted
Units installed from 2017	100	10
Units installed between 2004-2016	450 in 2020[23]	129
Units installed before end 2004	600	58

6.4.2 Control of NOx

A current challenge for the implementation of emission control technologies in East Asia is the wide variety of coal types which are used. Coal used in East Asia is generally sourced from within Asia and sometimes imported from other countries such as Australia and South Africa for the more efficient power plants located near the coast, because of the better quality of these coals (refer to **Figure 6-3**).

[19] Emission Standards for Japan, International Centre for Sustainable Carbon, 2019
[20] https://cdn.cseindia.org/attachments/0.76763300_1533289119_NOx-Control-Technologies-for-Thermal-Power-Stations-Factsheet.pdf, accessed August 2021
[21] https://www.teriin.org/sites/default/files/2020-02/emissions-control-thermal-power.pdf, accessed August 2021
[22] Emission Standards for India, International Centre for Sustainable Carbon, 2019
[23] https://www.downtoearth.org.in/news/pollution/environment-ministry-relaxed-nox-norms-but-did-it-need-to--74007, accessed August 2021

Figure 6-3 : Worldwide coal quality - energy content (kcal/kg)



Source: *Aurizon beyond 2020: Sustainability report 2014*

Domestic Asian coals are low rank, high ash coals (Indian domestic thermal coal – 18,500kJ/kg, 25-45% ash content), leading to lower plant efficiencies. Typically, plants have been designed to process the more traditional low-sulfur coal, however, some are now being designed to handle lignite sub-bituminous and anthracite coals. The large range in coal feed properties (sulfur, moisture, ash and volatile content), and the changing regulatory environmental requirements means that there will be a variety of emissions control systems implemented.

6.4.2.1 China

In the 2000s, low-NOx burners started to be introduced to Chinese power plants, but their effects were limited. From 2011, the central government started giving price premiums to coal-fired power plants with SCR. Given the incentives, SCR has been developed rapidly in China and V_2O_5/TiO_2-based catalysts, which can achieve a NOx reduction efficiency of more than 85%, have been widely used[24]. By 2014, SCR units were installed in 80% of coal-fired power plants and made up almost 95% of installed denitration capacity. Additional efficiency of emissions reduction has been attained by increasing the catalyst in the SCR reactor from two layers to three layers. This method has allowed plants to increase the NOx removal efficiency from 75%–85% to 90%.

Low NOx burners and flue gas denitration technologies have also been a major focus. A combination of LNB-SCR technology is the dominant NOx reduction method used in Chinese thermal power plants to meet the strictest emissions standards of 50 mg/Nm^3.[25] While LNB are used for wall fired units, tangentially fired units are typically coupled with SCR for additional NOx reduction[26].

6.4.2.2 Japan

SCR technology was first developed in Japan and started to be applied in Japanese thermal power plants in the late 1970s. Although some sources claim that SCR use is widespread in Japanese coal-fired plants, there is limited information available regarding the rates of adoption of various NOx reduction technologies. Coal continues to play a major role in Japan's power generation industry and the government has not implemented strict regulations on NOx emissions levels (see section 6.4.1.2).

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[24] https://reader.elsevier.com/reader/sd/pii/S2095809920301417?token=C0F93AA0F471B0D6726BA88EA5AE0F3D81D3EE200E7B60EB204A5CD71302BBC07B4F1B062D78975BE605DEC52311CC5C&originRegion=us-east-1&originCreation=20210825054600

[25] https://reader.elsevier.com/reader/sd/pii/S2095809917300814?token=141840DD3A570439C21CF0F723746D01BCF10F4D2AFB3291CBFB413F49A5FA928FE5A9B98E645B813E2217653FDE03FC&originRegion=us-east-1&originCreation=20210825054533

[26] Tangshan Power Station, Shanwei Haifeng Power Station

6.4.2.3 India

Following the implementation of stricter regulations to the Indian power industry, power plants are being required to install NOx control systems. The older power plants (installed before 2016 and 2004), which are required to meet more lenient standards (600 and 450mg/Nm^3 respectively), will be able to meet emissions targets with primary modifications. These include combustion optimisation, low NOx burners, and overfire air. This is by far the majority of the coal fired plants currently in operation in India. In 2019, NTPC (India's largest power utility) awarded a USD20 million contract to GE Power India for the supply and installation of low NOx combustion systems for 10GW of its thermal power plant capacity across the country[27].

Power plants constructed after 2017, which are required to meet the stricter standards of 100 mg/Nm^3 are required to consider SNCR and SCR technologies in order to achieve greater emissions reductions.[28] To date, implementation of SCR and SNCR technologies has been limited as investigations are continuing into the applicability of these techniques to Indian coal. NTPC have conducted pilot tests on some of their plants and reported that key emissions parameters could not be met using these technologies due to the high ash content of Indian coal[29]. It is unclear how Indian power plants will be able to meet the government's 2022 targets.

6.5 NO_x Emission Control Summary

Table 6-6 provides a list of major technologies used in international jurisdictions to manage NOx emissions from coal fired power stations. Note the controls are generally ordered in terms of lowest cost to highest cost options. Costs are considered in more detail in Section 9.

Table 6-6 Technological and other controls

NOx Control Mechanism	Effectiveness (emissions reduction potential)	Advantages (A) and Disadvantages (D)
Biomass Co-firing [30]	Up to 2% (based on 3% cofiring at VPPS)	A: Reduces GHG and SOx emissions at the same time D: Milling issues limit cofiring of 3%, which results in an annual average of 1% cofiring
Burner optimisation for NOx control	Up to 10% depending on current burner setup, burner imbalance.	A: Optimises current burners using air staging for improved NOx control rather than combustion efficiency D: Loss of plant efficiency with higher carbon in ash and higher fuel cost Increased operating costs
Neural Network	10-15%[31] without Low NOx burner or OFA	A: Optimises current burners for NOx control rather than combustion (GHG) efficiency D: DCS capability, air supply & fuel equipment

[27] https://www.ge.com/news/press-releases/ge-power-wins-inr142-crore-contract-nox-reduction-technology-across-10gw-power accessed August 2021
[28] https://www.indiaspend.com/indias-largest-power-producer-wants-nox-norms-diluted-for-new-coal-plants/ accessed August 2021
[29] https://www.reuters.com/article/us-india-ntpc-emissions-exclusive-idUSKBN1YN0G1 accessed August 2021
[30] Biomass co-firing has been widely used in Europe (Xu et al. 2020) and up to 10% co-firing has been shown to be viable for implementation in Australian coal plants without modifications to existing burners (Australian Government, 'Facilitating the Adoption of Biomass Co-firing for Power Generation' 2011). More details on biomass cofiring are available in Section 8.3.
[31] Neural networks prove effective at NOx reduction, Article from NS Energy, 19 May 2000

NOx Control Mechanism	Effectiveness (emissions reduction potential)	Advantages (A) and Disadvantages (D)
Low NOx burners	Up to 50% coupled with OFA	A: Primary measure more cost effective than SNCR D: Loss of plant efficiency with higher carbon in ash + increased fuel consumed and auxiliary load May increase boiler backend temperatures, and require high temperature filter bags. (which is a high ongoing cost) Increase in tube wastage from reducing conditions Height of furnace may limit LNB to close coupled overfire air, with lower NOx reduction potential
Over-fire air (OFA)	<10%	A: Limits combustion temperatures D: Limited space for ducting / windbox Fouling, tube corrosion
Flue gas recirculation (FGR)	<20%	A: Limits combustion temperatures D: Limited space for ducting and recirculation fan. Fouling, tube corrosion
Selective non-catalytic reduction (SNCR)	30-50%	A: High level reduction potential D: High capex / opex Handling and storage of hazardous ammonia, and emissions to air of ammonia (slip)
Selective Catalytic reduction (SCR)	80-90%	A: Vey high reduction potential D: Extremely high capex / opex Large footprint required Handling and storage of hazardous ammonia, and emissions to air of ammonia (slip)

The published performance data for retrofitting NOx mitigation equipment and controls and indicative costings between control technologies tends to be 15-20 years old. There is an absence of more recent data and publications as utility owners are not investing in PC plants. Viability in US and EU markets for retrofits and upgrades was in the late 1990 early 2000 period with the coal fired plants now having reached or reaching the end of their lives.

7. VPPS NOx emissions benchmarked Nationally and Internationally

7.1 Australian Power Stations

VPPS NOx emissions are mid-range when compared to the other NSW coal fired plants (refer **Table 7-1**).

- similar to Liddell, which also has a Tangential firing system.
- lower than wall fired units (Bayswater and Mt Piper)
- higher than units equipped with Low NOx burners (Eraring is the only NSW station with Low NOx Burners, which were retrofitted as part of the unit uprating to 720MW in 2011.)

VPPS NOx emissions are mid-range when compared with interstate power plants. The Victorian power stations fire brown coal which has lower NOx emissions due to lower combustion temperatures. Black coal power stations of similar vintage generally have higher NOx emissions than VPPS, while more modern stations, equipped with low NOx burners, generally have lower emissions than VPPS, but not always. Each state has different standards for reporting NOx, and therefore the emissions are compared as NOx intensity kg/MWh from NPI data, rather than NOx concentration (mg/Nm^3) (refer **Table 7-1**).

Table 7-1 Australian Coal-Fired Power Stations NOx emissions

Plant	State	Output (MW)	Year	Description	NOx Intensity[1] (kg/MWh)	NOx Concentration (mg/Nm^3)	NOx Limit 100 percentile (mg/Nm^3)
Vales Pt	**NSW**	**2 x 660**	**1979**	**Tangentially fired**	**2.27 (current)**	**500-600**	**1500**
Liddell	NSW	4 x 500	1975	Tangentially fired	-	567[2]	1500
Bayswater	NSW	4 x 685	1985	Wall fired	-	790[2]	1500
Eraring	NSW	4 x 720	1982	Wall fired, low NOx burners (retrofitted as part of uprate)	-	313[2]	1100
Mt Piper	NSW	2 x 700	1995	Wall fired	-	745[2]	1500
Gladstone	QLD	6 x 280	1976	Wall fired	3.68	-	
Tarong	QLD	4 x 350	1984	Wall fired, low NOx burners	2.34	-	
Callide B	QLD	4 x 350	1988	Wall fired, low NOx burners	4.11	-	
Stanwell	QLD	4 x 350	1996	Wall fired, low NOx burners	3.62	-	
Kogan Ck	QLD	1 x 750	2007	Wall fired, low NOx burners	1.11	-	
Millmerran	QLD	2 x 400	2001	Wall fired, low NOx burners	2.03	-	

Note 1: NOx intensity (kg/MWh) are from NPI NOx emissions data for 2019-2020, except Vales Point where our more recent estimate has been used (accounting for the lower emissions post wide-range tip removal)

Note 2: NOx figures are averages from June 2021 monthly reports.

7.1.1 NOx Emission Controls

The most common NOx control technology used in Australia is low-NOx burners (for wall fired units), installed on all units built since the late 1990s. NSW utility power stations were built before the mid 1990s, and were not equipped with low NOx burners. Eraring Power Station (wall fired) is the only coal fired plant in NSW fitted with low-NOx burners, which were installed as part of the capacity increase in 2011/12. In Australia, there are no SCR or SNCR systems, or reburn or FGR technologies, operating at any coal fired power stations, as these plants were built prior to these technologies being developed, or there was no requirement to meet low NOx limits. None of the Tangential fired units similar to VPPS, have been retrofitted with low NOx burners or additional post combustion controls.

A 2019 study found of air quality at 5 locations around NSW found that 1-hour average concentrations of NO_2 were good or very good throughout the entire year.[32] This demonstrates that additional NOx control measures are not required for NSW coal power plants in order to meet ambient air quality regulations. This is in contrast to some other countries (see below) where poor air quality has led to strict air quality emissions standards and requiring retrofit of NOx controls on existing plants.

7.2 Emissions from Power Plants in the USA

Annual U.S. electric power industry NOx emissions have declined by 76% between their peak in 1997 and 2017. During this period, coal-fired generation was responsible for 76% of NOx emissions from the U.S. electric power industry[33]. In 1997, each MWh of coal-fired electricity generation produced 6.4 pounds (2.9kg) of NOx. By 2017, that rate had fallen to 1.5 lbs/MWh (0.7kg/MWh)[33]. The decrease in electric power industry NOx emissions has been driven by environmental regulations under the Clean Air Act Amendments (CAAA) of 1990, but also historically low natural gas prices eroding coal fired market share, coupled with baseload nuclear power.

The Commission for Environmental Cooperation (CEC) published emissions of NOx from fossil fuel-based electricity generation in the USA, Mexico, and Canada.[34] All 2,728 US power plants considered emitted a total of nearly 3,500,000 tonnes of NOx. Of these plants, 364 accounted for 90% of the total, with individual plant emissions ranging from 2,000 to 37,870 tonnes. **Table 7-2** below outlines the NOx emission intensity of the coal power plants generating a similar amount to Vales Point.

Table 7-2 NOx emissions rates for US plants (similar capacity to Vales Point)

Source	Plant yearly generation	Number of Plants	Emission Intensity
CEC, 2005[34]	7000 - 8000 GWh/year	20	0.63 – 4.18 kg/MWh
US Energy Information Administration 2019[35]	7000 - 8000 GWh/year	9	0.16 – 1.11 kg/MWh

7.3 Emissions from Power Plants in China

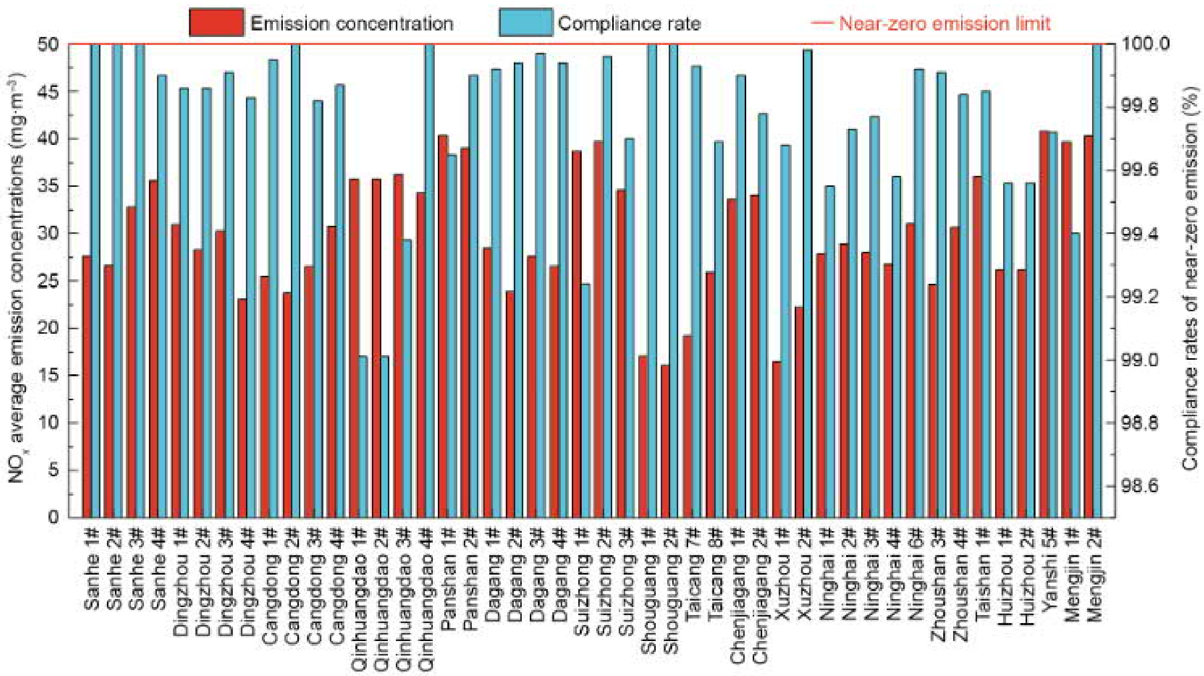
China is of a similar area as Australia, but with 45x the population density. Its coal fired power plant capacity is approximately 1050GW, which is 40x the coal plant capacity in Australia, 10x the coal fired capacity in the USA, and 800x the capacity of Vales Point. The rapid industrialisation of China, high population density and rapid urban growth, caused an air quality crisis in the late 2000s, led China to implement strict air emissions standards on all sectors, including on power plants.

Since 2011, the Chinese government started paying price premiums to coal-fired power plants with SCR NOx controls. As a result, NOx emissions started to decline significantly and, in 2015, NOx emissions were 81% of their peak values in 2011.

Wang (2020) evaluated the emissions from 46 units in China located at 17 power plants. The average NOx emission concentrations ranged from 16.1–40.79 mg/Nm^3 during 2017 (refer **Figure 7-1**). Emissions compliance (50 mg/m^3 limit) was >99% for all units and seven units achieved a compliance rate of 100%.

[32] Lake Macquarie – Wyong Review of Annual Ambient Air Quality Data 2019 – Delta Electricity & Origin Energy, by Todoroski Air Services
[33] https://www.eia.gov/todayinenergy/detail.php?id=37752 accessed August 2021
[34] http://www5.cec.org/sites/default/napp/en/north-american-emissions/nitrogen-oxides.php accessed August 2021
[35] https://www.eia.gov/electricity/data/emissions/ accessed August 2021

Figure 7-1 : Emissions from 46 units in China over 5-6 months in 2017[36]



The China Emissions Accounts for Power plants (CEAP) is a database of air emissions from China's power plants from 2014 to 2017, sourced from CEMS. This database includes over 2000 coal-fired power plants (approximately 5000 units) with a total capacity of 1050GW (as of 2020). There are CEMS installed on 99% of coal -fired units studied. There was a significant drop in emissions between 2014 and 2017. The mean NOx concentration from coal power stacks was 160mg/m^3 in 2014, dropping to 98mg/m^3 in 2015 and 53.4 mg/m^3 by 2017[37].

7.4 Benchmarking Summary

Vales Point NOx emissions are low to moderate when compared with other Australian power stations. The ambient air quality indicates additional NOx control measures are not warranted. The USA and China have much lower NOx emissions per utility, commensurate with lower emissions standards. This hasbeen required due to the higher concentration of power plants and other emitters in a smaller airshed resulting in a higher pollutant load and poor ambient air quality.

Table 7-3 Benchmarking Summary

	Vales Point	NSW[38]	Australia	USA	China
NOx intensity kg/MWh	2.27	1.3 – 3.0	0.94 - 3.68 (FY2020)	0.16 – 1.11 (2019)	-
NOx concentration mg/Nm^3	500-600	313-790	300 – 1200	-	53.4 (average 2017)
Comments	Tangentially fired		~50% LNB for wall fired units	>75% LNB ~50% SCR ~25% SNCR.	LNB (wall fired) >80% SCR (T-firing coupled with SCR)

[36] https://www.sciencedirect.com/science/article/pii/S2095809920301417
[37] 'CEAP Stack Gas Concentrations' and 'CEAP Summary Descriptions' datasets, 2020
[38] June 2021

8. NO_x Control Options Analysis

Jacobs has evaluated additional NOx emission controls, or mitigation measures that potentially could be used to reduce NOx emissions, where feasible. In general, wear causes imbalance in the fuel and air flow across all 48 burners on each unit, and requires ongoing maintenance to ensure combustion as designed.

8.1 Combustion Optimisation

Combustion optimisation, in the context of this report, signifies manual hands-on actions or maintenance activities for improving the furnace combustion such as:

- Ongoing maintenance on primary and secondary air control mechanisms (essentially good house keeping practices)
- Instrumentation calibration and validating the accuracy O_2 probe readings
- Operator training, daily efficiency and performance related feedback from shift supervisors and encouragement for operator manual intervention to improve the control of emissions.
- Operating the combustion system with the minimum intensity to reduce NOx production
- Periodic combustion tuning and optimisation reports

VPPS are pro-active with scheduled ongoing maintenance of combustion related equipment (fuel air dampers, auxiliary air dampers, burner linkages, tilting mechanisms, etc.) and testing of key instrumentation. VPPS are currently in the process of undertaking a project on Unit 6 to calibrate the O_2 probes and replace any seized air dampers. Unit 5 is scheduled immediately after Unit 6 with expected completion in November 2021[39]. A number of these activities require a unit shutdown and internal furnace scaffolding access, which requires a minimum of 10 days shutdown, and can only be undertaken during major outages.

The VPPS Operator training program[40] integrates modules specifically aimed at boiler efficiency, introduction to and understanding of NOx formation, carbon in dust (CID) and the knowledge to perform real time boiler optimisation. A daily meeting with staff provides feedback on performance indicators for each unit, which ensure operators maintain good practice, and address areas of shortfall.

Optimising the combustion to reduce the intensity of the flame and NOx emissions have to be balanced with detrimental effects to plant performance such as carbon in ash. The reduction in NOx emissions generally increases carbon in ash, as a result of reduced intensity of combustion. Unit 6 NOx reduction in 2021, was accompanied by an increase of Carbon in Ash from <3.0% to 3.6%. Any further operational changes to reduce NOx need to be weighed against the increased coal consumption, higher auxiliary load and resulting CO_2 emissions, and other knock-on effects. Higher fuel costs outweigh reduction in LBL fees. The higher the carbon in ash, the less attractive the ash is for recycling due to discolouration and reduction in strength as a cement additive. Carbon in ash > 4% could lead to a loss of ash recycling, requiring VPPS to landfill an additional 20% of ash.

Periodically, VPPS have conducted combustion tuning of the Units (refer **Section 4**). The ideal settings for the plant have been well established e.g. combustion O_2 levels have been reduced as far as is possible, and the role of operations is to maintain operation at these ideal conditions, within the constraints of variances in ambient conditions, coal quality, desired load, and Unit wear.

[39] VP correspondence Air Damper Unit 6 Progress Report 8/9/2021
[40] VP correspondence Panel School Modules 8/9/2021

8.2 Operational Upgrades

Operational upgrades, in the context of this report, refer to the measures to improve the coal grind, and combustion feedback (CO after economiser).

Table 8-1 Potential Upgrades of Existing Boiler Controls and Operation

Control Mechanism	Upgrade	Reasons & limitations
Control of coal grind	Periodic PF sampling Rotating classifier	**Reason:** Permit monitoring of mill performance and to improve coal fineness **Limitation:** No headroom to fit rotating classifiers
Control of air	Overhaul / replacement of damper actuators to be completed by Nov 2021	**Reason**: Incorrect positioning of dampers without position feedback. (96 air registers per boiler) Delta have implemented DCS automated stroking of dampers and inspection to ensure correct operation.
CO feedback	CO monitor before or after economiser on fluegas path A & B	**Reason:** Permit online monitoring of combustion, and early detection of upset conditions. **Limitation:** Combustion tuning has been done by with reports by consultants and the OEM, but without much improvement. CO analysers would require further evaluation and cost benefit analysis.

Operational improvements may permit Vales Point to reach a NOx limit of 800 mg/Nm^3 on a near continuous basis. Unit 5 achieved 800 mg/Nm^3 limit for 99.6% of the time throughout 2017-2021, and averaged 609 mg/Nm^3 with a maximum of 1,245 mg/Nm^3 (furnace 5A, 2020). Unit 6 is achieving similar NOx emission and maximum emission levels as Unit 5, following the removal of wide range tips. Unit 6 achieved the 800 mg/Nm^3 limit for 99.7% of the time since conventional burner tips were fitted. It averaged 532 mg/Nm^3 with a maximum of 976 mg/Nm^3 (furnace 6B). The net average for Unit 5 & 6 in the range of 570-590 mg/Nm^3.

Reductions in NOx have been demonstrated at many coal fired facilities through operational improvements. However, there is no data from identical boilers operating on the same coal. Therefore, the amount of improvement cannot be quantified, nor can it be said with certainty, that the unit would achieve 800 mg/Nm^3 100% of the time, due to inherent and unavoidable variability in plant performance.

8.3 Biomass Cofiring

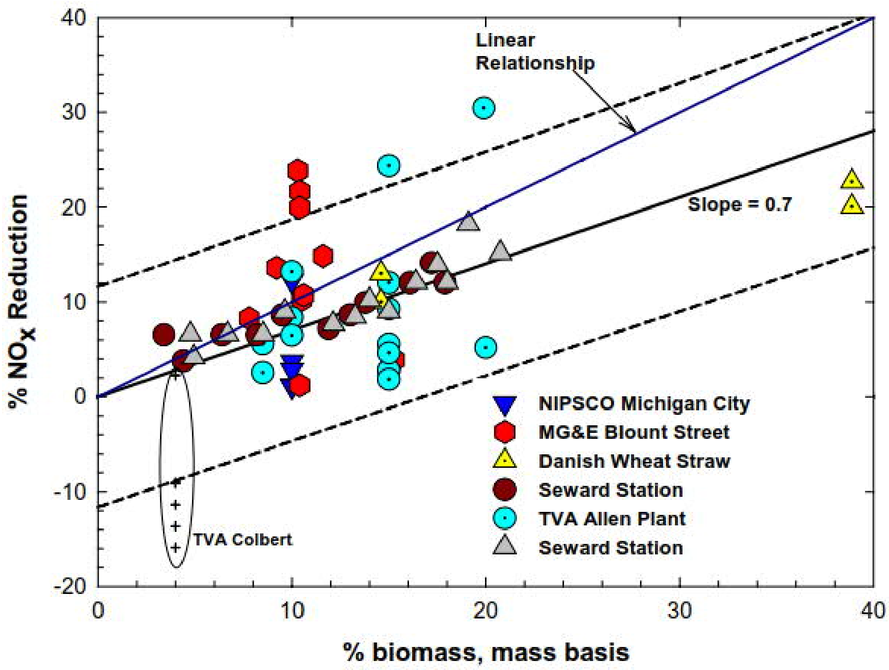
Coring biomass in coal fired power stations reduces combustion temperatures and NOx emissions due to the lower calorific value and higher moisture content of biomass. The results for NOx reduction from biomass at other coal fired power stations are variable (refer **Figure 7-1**), however there is a general trend of reduction in NOx emissions. Biomass is more widely used in Europe and America, where biomass is cofired up to 10% and even 100% in some plants, due to its renewable status.

Delta has co-fired biomass (woodchips) from 1% to 3% of heat fired, EPL No. 761 permits co-firing biomass up to 5%. Delta prefer to limit cofiring to 3% due to mill constraints.

The biomass cofired at VPPS is woodchip, which is mixed with the coal on the rising conveyor into the coal bunkers, and is fired using the existing coal mills and burners for combustion. The issues with co-firing biomass above 3% have been largely increased load on the coal mills, which has led to an increase in carbon in dust, as well as blockages when firing a blend > 3%. The mills have had issues with biomass build-up on the table, and the higher moisture load of the biomass decreases primary air temperature.

The effect of biomass co-firing on NOx has not been quantified at VPPS, but it is expected to be minor with the low quantities of biomass currently able to be co-fired with coal (i.e. <3%). Other studies have found an average 0.7% reduction in NOx for every 1% contribution by mass of biomass (refer **Figure 8-1**). At the rates fired at VPPS, the NOx improvement is unlikely to be detectable with the station instrumentation.

Figure 8-1 Biomass Co-firing NOx Reduction



Co-firing biomass is only considered practical for minor reductions of NOx concentrations at VPPS. Large NOx reductions would require much larger supplies of biomass and changes to plant to overcome mill issues. In recent years, approximately half of the UK's former coal stations have converted to 100% biomass firing, or gas firing (for peaking)[41], with new combustion systems. This has been driven by a supportive regulatory environment, and a reliable source of biomass (noting that Vales Point only uses suitable waste wood products where other countries utilise whole trees). Similarly, it would be technically feasible, but prohibitively expensive, to convert Vales Point to 100% biomass firing (e.g. using wood pellets), however without a reliable and much larger cost effective source of biomass, this is not practical.

8.4 Low NOx Burners and Overfire Air

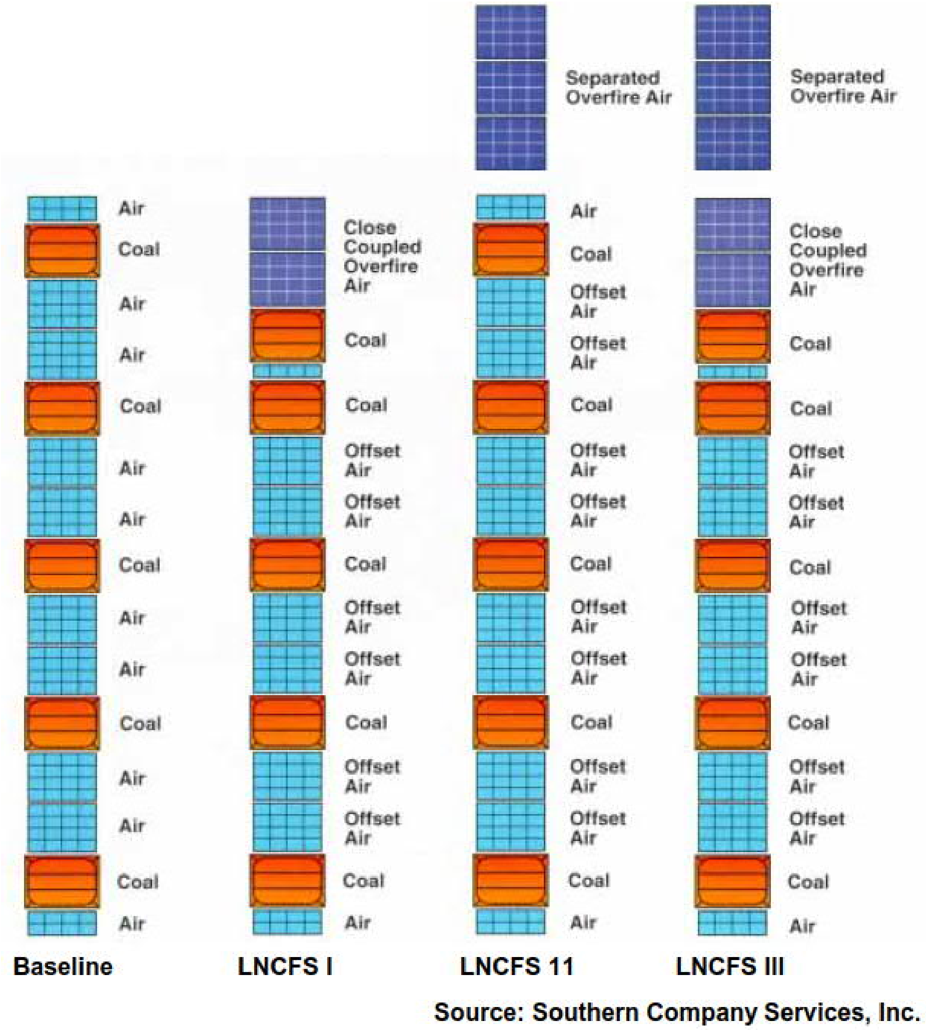
Low NOx burners are the traditional starting point for NOx reduction. Retrofit of low NOx burners to existing plant is usually the most cost-effective means of NOx reduction. However, there are limitations on retrofit of Low NOx burners which may make them impractical for certain furnace geometry.

Low NOx burners operate by lowering the peak temperatures of combustion, achieved through internal air staging to control the combustion. Initial combustion occurs in a fuel rich zone, and overfire air is generally added to complete combustion of char. The effect of staging combustion in this way is to limit peak flame temperatures.

Tangentially fired (T-fired) boilers, such as those at Vales Point, have a different style of burner to wall fired boilers, and there are fewer suppliers of low NOx burners for this type of design. Most low NOx burner development has been conducted on wall fired boilers, as tangentially fired boilers have inherently lower NOx levels with less potential for improvement. Nevertheless, there are several variations of Low NOx burners for T-fired boilers (refer Figure 8-2), with the designs available to suit a variety of furnace geometries. The

[4141] Drax, Kilroot, Lynemouth, Uskmouth, Eggborough changed fuels, while Aberthaw, Cottam, Rugeley, Longannet, Ferrybridge closed two principle variations are the positioning of overfire air: close coupled (CCOFA) for moderate levels of NOx reduction and separated (SOFA) with higher levels of NOx reduction.

Figure 8-2 Low NOx Burner variations for Tangentially Fired Boilers



8.4.1 Burners Out of Service

Burners Out Of Service (BOOS) is essentially a form of air staging using overfire air, but through different operation of current equipment. Burners in service have their airflow reduced, and the balance of the air is inserted through the out of service burners.

BOOS operation could be applied at Vales Point with operation of 5 mills (B-F), and overfire air applied through 'level A' burners. However, both coal quality and mill capability have, at times, required operation with all 6 mills at full load, which leaves no out of service burners for overfire air. Even when full load can be achieved on 5 mills, mill maintenance requirements mean A level burners may be required to be in service. In addition, NFPA compliance issues (combustion safety) would need to be overcome.

BOOS would be a low capital cost option, but only useful for lower loads when it is possible to operate mills B-F only. Potentially NOx reductions of 5% could be achieved.

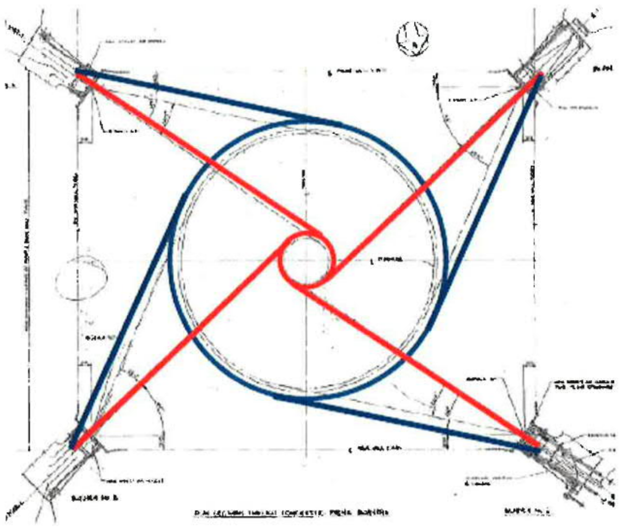
8.4.2 Burner Tilt

Reducing burner tilt (downwards) increases the residence time for combustion in the furnace and permits a reduction in NOx. However, it also increases the plant heat rate through reduction in superheat / reheat temperature and would not be practical. (A reduction in steam temperature or reheat temperature by 10°C will reduce plant efficiency by approximately 0.5% each, therefore increasing CO_2 emissions).

8.4.3 Burner Optimisation for NOx Control Using Air Staging

One means of air staging is a concentric firing system (CFS - refer **Figure 7-3**), which ***offsets*** the injection angle of the secondary air nozzles, to delay combustion and optimise NOx control. This is a moderate capital cost project for the modification of the existing burners (compared with other options), as it requires the burners to be removed and the secondary air nozzles to be modified to permit a different injection angle. GE does not state the NOx reduction potential, but it would be expected to be in the order of 10%.

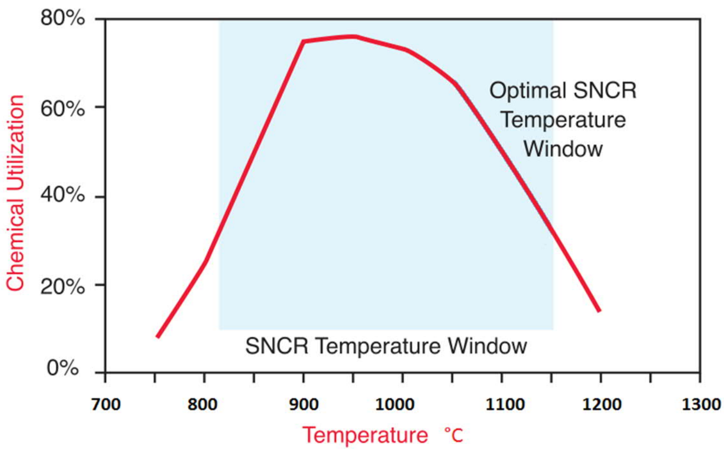
Figure 8-3 Air staging by secondary air offset



8.5 SNCR (post combustion)

Selective Non-Catalytic Reduction (SNCR) systems convert NOx into nitrogen and water with an injected reagent such as ammonia (anhydrous or aqueous) or urea. The reagent injection area is in the upper furnace and convection pass areas, which correspond to the following temperature window (refer Figure 8-4). SNCR has a relatively high capital cost with high ongoing operating costs.

Figure 8-4 Temperature for Reagent Injection



The location of the optimum temperatures for injection is often located in the superheater and reheater area. The location of superheaters / reheaters may limit the locations for injection of ammonia, and its mixing in the flue gas. The penetration of the ammonia from side wall injection system is limited in larger furnaces, which limits NOx reduction potential. One supplier markets water cooled lances to permit ammonia injection in the centre of the furnace to overcome this limitation. A further consideration for the Vales Point boilers is they have a higher velocity flue gas design, resulting in a reduced residence time for ammonia reactions within the optimal temperature ranges. This would limit the potential NOx reduction efficiency.

Urea is the preferred from a handling point of view, as it is non-hazardous unlike ammonia, however generally process conditions will dictate reagent which is preferred.

SNCR systems can be used in combination with low NOx burners, so achieve NOx reduction which approaches 90%.

There are downsides from ammonia injection, which need to be considered, and may limit injection rates.

i. Ammonia reacts with sulfur and forms ammonia bi-sulphate. This causes plugging of the economiser, airheater and fabric filter bags. Boiler tube wastage may occur near the injection zone.

ii. Unreacted ammonia will be discharged to atmosphere as “ammonia slip” (NH_3 emission 5-30 mg/Nm^3).

iii. nitrous oxide (N_2O) will be discharged to atmosphere (10 – 30 mg/Nm^3) which has a high global warming potential of 300.

8.6 SCR (post combustion)

Selective Catalytic Reduction (SCR) systems convert NOx into nitrogen and water with an injected reagent (anhydrous or aqueous ammonia or urea) and a catalyst (such as titanium oxide or zeolite). The catalyst permits high reduction (up to 85%) in NOx emissions, and lowers the temperature at which NOx reduction takes place. The reagent injection area is between the economiser and the air heater.

SCR is also the most expensive form of NOx reduction in both capital and operating costs. The use of a catalyst is also problematic with coal firing because of the issue of catalyst blinding from ash particles, and the need for sootblowers. Catalysts need to be located in vertical gas flow to allow ash to pass through. The efficiency of the catalyst also degrades over time from elements in the coal (e.g. potassium), which is also known as poisoning, requiring the catalyst elements to be replaced periodically.

Similar to SNCR, there are downsides from ammonia injection,

i. plugging of the airheater and fabric filter bags from ammonia bi-sulphate.

ii. 2-2.5 MW increase in auxiliary load due to increase in pressure drop through system and compensation required by ID fans.

iii. Increase in parasitic load impacts overall net electrical efficiency and increase in CO2 emitted.

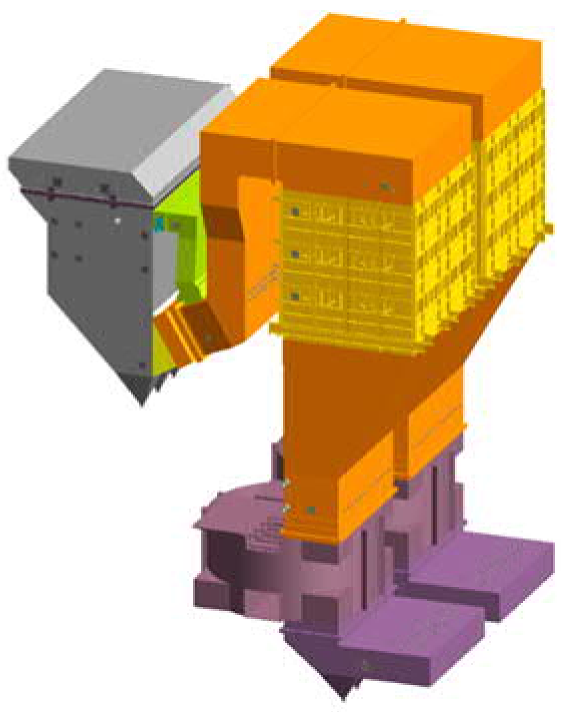
iv. Increasing ammonia slip with two shifting and operation at low loads may cause higher concentration of ammonia in fly ash and may affect its reuse value.

v. SCR variable cost is very sensitive to operating capacity, capacity factor and boiler loads.

Ammonia slip for the SCR system is less than with SNCR systems, and nitrous oxide (N_2O) emissions are negligible.

The boiler would require a new backpass to be constructed between the economiser and airheaters (similar to Figure 8-5), however there is insufficient space at the rear of the Vales Point boiler due to the coal conveyors being located between the boiler and the bagfilter.

Figure 8-5 Ammonia injection grid and SCR catalyst (BHI-FW)



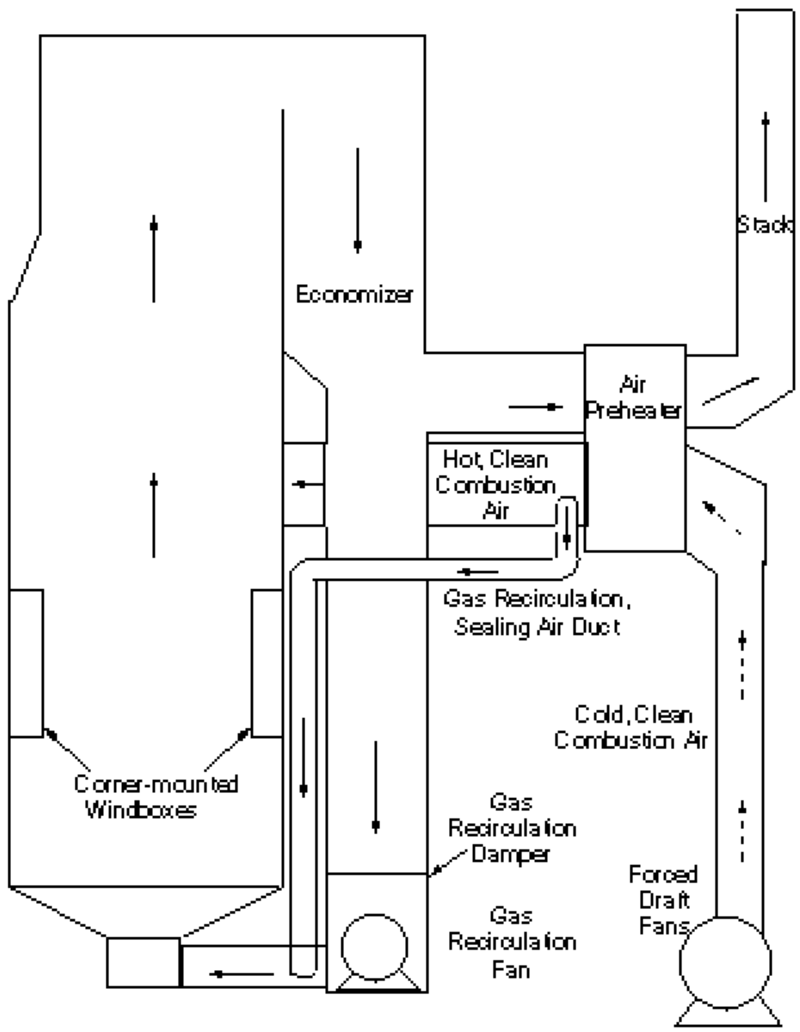
8.7 Flue Gas Recirculation (FGR)

Flue gas recirculation (refer to **Figure 8-6**) takes 10%-30% of the flue gas and recirculates it to the burners, diluting the combustion air, and reducing peak flame temperatures, and decreasing thermal NOx production.

Flue gas recirculation increases the flue gas volumes through the furnace and convective passes substantially. The Vales Point boilers already have higher than desirable gas velocities, which cause erosion problems for the pressure parts and reduce residence time for combustion. Flue gas recirculation at Vales Point would only exacerbate the existing erosion problems or require the units to be derated to maintain velocities within acceptable limits. FGR dilution of the flame temperature would reduce the radiant heat transfer to the reheater / superheater surfaces, which would impair unit efficiency by reducing steam temperatures, and lead to a loss in Unit output.

Flue gas recirculation can be used, particularly when the boiler is designed for it from the outset, but is not considered practical for retrofitting in the case of Vales Point.

Figure 8-6 Flue Gas Recirculation



8.8 Steam / Water Injection

Flame temperature reduction by dilution using fluids such as steam or water would reduce NOx emission, but have adverse impacts on the Unit performance. It would lead to loss of boiler efficiency through increased stack losses, high water consumption, and loss of reheat and main steam temperature. While water injection is used for NOx reduction in liquid fuelled gas turbines, this occurs only for short term operation, and it is not considered practical for fired boiler NOx reduction.

8.9 Reburning

Reburning (also known as fuel staging) is a technique of NOx reduction where NOx formed during the main combustion stage is then removed under a subsequent combustion stage. The majority of the fuel is burnt in the lower part of the furnace, at stoichiometric conditions. A small proportion of the fuel is burnt in the upper furnace under reducing conditions. The reducing conditions form hydrocarbon radicals, which strip the oxygen from NO_2 formed in the main combustion area. Lastly overfire air is added to complete combustion. Reburning is applied mostly with natural gas firing. However natural gas is cost prohibitive for base load power and demand would likely require a new natural gas pipeline from Sydney.

Reburning is not practical for the Vales Point boiler design, due to the short height available in the furnace, which would not permit a reburn zone above the main burners.

8.10 Neural Network Combustion Optimisation Software

Artificial intelligence technology (notably neural networks or data analytics) combined with combustion knowledge in boilers, enables power plant specialists to further optimise combustion and reduce emissions.

The cost of installing the neural network combustion optimisation hardware and software is largely dependent on *compatibility*. That is, whether the control system has been replaced with more modern instrumentation and actuators and has a distributed control system (DCS) that can provide data collection and storage of operating parameters recorded in real time. If the boiler has a less sophisticated control system, there are still options to develop a closed-loop application of neural network system but will require additional hardware and instrumentation systems for data collection and system control. Vales Point have within last two years upgraded units 5 and 6 to the more sophisticated Siemens SPPA-T3000 DCS. The condition and suitability of actuators and dampers at site, instrument requirements and location, instrumentation and transmitters calibration or the replacement thereof also significantly contribute to the overall project capex costing.

The artificial intelligence (AI) systems offered by original equipment manufacturers may help reduce NOx emissions and lower the heat rate. GE in Australia, offer “BoilerOpt” variants. The degree of benefit does depend on whether the existing tangential fired PC boiler incorporates low NOx burners and over-fire air (OFA) systems or not. It is also important to distinguish whether the ‘neural networks’ is associated with a closed loop supervisory operating control or an open loop control. The closed loop control system “has a set of mechanical or electronic devices that automatically regulates a process variable to a desired state or set point without human interaction”. If linked with an open loop control system, the required corrective measures or process adjustments are performed by operators hands on actions.

With a neural network system associated with a closed loop supervisory operating control, low NOx burners and OFA installed, a 25-30% NOx reduction from baseline values can be achieved[42].

For similar plant to Vales Point[42] units 5 and 6 (i.e. ICAL design, tangentially-fired, twin furnace, sub-critical steamer, 500-600 MW, sophisticated DCS control system), with a neural network system associated with a *closed loop supervisory operating control* and with no retrofitted burners or OFA, a 10-15% NOx reduction relative to baseline values were achieved during testing[42]. With reference to GE BoilerOpt Lite technology 10-15% NOx reduction full auto-mode.[43] Heat rate improvements of between 0.2-0.6% were attained[42].

[42] Neural networks prove effective at NOx reduction, Article from NS Energy, 19 May 2000
[43] GE Boiler DB Plus module Fact Sheet & Case study

In early 2010, Siemens temporarily installed at Vales Point for a 6-week trial period the SPPA-D3000 Plant Monitor system to demonstrate its capability. At that stage, the units still had the old Distributed Control System (DCS) and not the new SPPA-T3000 Distributed Control System.

The Siemens SPPA-D3000 2010 version was an on-line 'real time' monitoring system and used archived I&C data to learn the normal behaviour of the plant or systems with the aid of "neural networks". By continuously comparing current operating data against "learned" normal response of the plant, the software package detected fluctuations in the process parameters or detected transient problems prior to being notified by a machine protection system. The user is informed in this case of any discrepancies but relies on the operator attendance to address or action the warnings or process deviations. This is referred to as an open loop control system.

The lessons learnt from the trial of the SPPA-D3000 Plant Monitor at VPPS were:

- It is resource intensive and would be expensive to maintain.
- The amount of instrumentation required, the age and condition of the control devices ended up being a limiting factor.
- Due to the direct and indirect costs and the lack of confidence in performance gains, the system was not purchased.

The basic package, in terms of hardware and software supply, tag mapping, model fine tuning and testing at site shall cost $750,000 to $1m[44] [45]. Adding plant and equipment upgrades, servicing, replacement or upgraded instrumentation and supply air controls, installing closed loop controllers, the indicative total capex costing is referenced in **Table 8-3** per unit. The average fixed operating cost for similar plants per unit is $75,000-85,000 per year[44], but with the higher Australian cost of human resources this figure could be higher.

8.11 Experienced and Competent Retrofit Partner

In the preceding sections of this report, the standalone best available technologies for retrofitting pulverised coal fired boilers to reduce NOx emissions were discussed. A further **key factor** is the need for a competent partner able to retrofit such systems. An 'integral partner' must have capabilities to provide more than the overall recommended product solution. They need the expertise to fully integrate the product into the existing boiler and comprehensively review or re-engineer the existing balance of plant or ancillaries.

There are several technical considerations, depending on the product or combination of emission reduction solution products selected. For example:

- Increased air side pressure drop to achieve the required fuel/air staging in the burner. This requires reviewing of the existing FD fans with the burner supplier knowledge and expertise.
- Thorough review of the furnace geometry due to potentially larger NOx flames, preventing wall impingement or tangentially fired flame patterns (CFD modelling).
- Examining current wind box design and dimensions, whether they need to be removed, replaced or just modified and the various other potential consequences
- The pros and cons of eliminating or reducing air preheat, the impact on boiler efficiency verse NOx reduction.
- The impact on ID fan sizing when considering FGR, SCR or SNCR.

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[44] Implementing EPA's Clean Power Plan: A Menu of Options, Chapter 1. Optimize Power Plant Operations, NACAA, May 2015, Table 1-4, Table 1-6

[45] Correspondence dated 24/8/2021 from Stuart Banks, Australia, New Zealand & Pacific Islands Region Leader Steam Power, Asia – Indicative Costings

These are only a few of the burner project dynamics, complexities and interrelated elements that a competent technology 'partner' must assist in working through and effectively execute to have a successful retrofit project and achieve the lower NOx emission outcome.

With the environment in Australia where boiler OEM's or large international companies with pulverised fuel firing technologies are withdrawing from the market, sourcing a competent and capable 'integral partner' is very real issue. The loss of the access to the solution products is one aspect, the loss of thermal design engineers and the removal of these experienced technical persons and site erection contractors from the industry has a knock-on effect.

The original OEM (ICAL/Alstom) for the Vales Point Power Station now falls under the GE Boiler banner. Direct correspondence with the GE Power Portfolio head for Australia stated that GE no longer supplies low NOx burners in Australia[46]. Ex-GE colleagues can be recommended and there is the option to pursue Chinese boiler companies operating under GE Boiler license agreements, but these agreements are restricted to China and where approved by GE for neighbouring countries. Without the right 'partner', the *risks and costs are significant and prohibitive*.

8.12 Summary

The choice of pollution control equipment for a coal fired power plant must consider lifetime technology costs as the basis for any investment. The technology costs vary greatly with specific removal requirements and coal characteristics. The following tables (**Table 8-2** and **Table 8-3**) summarise the key technologies available and the indicative retrofitting costs for pulverised coal firing utilities in Australian conditions and provide some guidelines for application.

Table 8-2: NOx Emissions Control Technologies

Control Technology	Description	% Reduction in NOx	Retrofit Capital Cost per unit[47]	Total O & M Cost
LNB	Combustion modifications can provide a minimal level of NOx reduction.	10 – 40%	A$29 – 84 per kW [40]	0.17 -1.3 A$/MWh [0.17]
LNB & OFA	Combustion modifications can provide a meaningful level of NOx reduction.	25 – 50%	A$44 – 96 per kW [64]	0.3 - 0.85 A$/MWh [0.3]
SNCR	Direct injection of urea or ammonia into the flue gas	30 – 50%	A$29 – 76 per kW [42]	2.0 - 6.9 A$/MWh [3.4]
SCR	Install catalyst elements in the flue gas stream to promote NOx reduction	80 - 90%	A$100 - 322 per kW [180]	1.5 - 5.85 A$/MWh [2.4]
NEURAL NETWORK	Install continuous combustion optimisation software to reduce NOx	10-15%	A$3.8 – 4.6 per kW [3.8]	0.012-0.013 A$/MWh [0.012]
Notes: All costs are indicated and sourced from Australian based studies and publications. Values in [ ] brackets are an indicative cost for Australian based utility using Central Coast coal and load factor of 75%. CAPEX cost for installing Neural Networks in an older technology combustion system are indicative and based on US published data factored for Australian conditions. Site specific factors with potential equipment and instrument upgrades could further increase costs.				

Published costs for retrofitting emission control systems vary considerably and are both site and country specific. The costs are also dependant on technical and financial factors such as operating hours, operating loads, removal efficiency, boiler configuration, furnace size and quality of coal fired. The figures have not been specifically adapted to the Vales Point site, but the values in square brackets are indicative of costs for

[46] Correspondence dated 17 & 19/8/2021 from Stuart Banks, Australia, New Zealand & Pacific Islands Region Leader Steam Power, Asia - License
[47] CCSD (January 2008) Analysis of Pollution Control Costs in Coal Based Electricity Generation Appendix D

an Australian utility using Central Coast coal and a load factor of 75%. This data is indicative and should be used to provide budgetary estimates of pollution control costs to be used for estimating the economic feasibility of a project.

A summary of the various NOx Control Options is presented in **Table 8-3** below:

Table 8-3: NOx Emission Control Summary

NOx Control Mechanism	Emissions reduction potential	Capital Cost per unit	O&M Costs ($ / MWh)	Advantages (A) and Disadvantages (D)
Biomass Cofiring	~2% estimate, limited by 3% cofiring	n/a	Up to 3% co-firing maintains similar costs as current (woodchip price dependent)	A: Reduces GHG and SOx emissions at the same time D: Sourcing of sufficient quantities of biomass
Burner optimisation for NOx control using air staging	Up to 10% depending on current burner setup, burner imbalance.	$5-6M	0.05 (lower costs than other measures below)	A: Optimises current burners using air staging for improved NOx control rather than combustion (GHG) efficiency D: Minor loss of plant efficiency with higher carbon in ash
Neural Network	10-15% without Low NOx burner or OFA	$2.5 – 3.0M	0.012 – 0.013	A: Optimises current burners for NOx control rather than combustion (GHG) efficiency D: Age of DCS, air supply & fuel equipment. Additional & new instrumentation
Low NOx burners	Up 50% with OFA	$30-60M	0.17 - 1.3	A: Primary measure more cost effective than scrubbing D: Minor loss of plant efficiency with higher carbon in ash. Original ICAL equipment technology holder withdrawn from market
Over-fire air (OFA)	<10%	$0.2- 1M	No additional ongoing operating costs Minor additional maintenance costs	A: Limits combustion temperatures D: Limited space for ducting / windbox (hence range in cost estimate) Fouling, tube corrosion

NOx Control Mechanism	Emissions reduction potential	Capital Cost per unit	O&M Costs ($ / MWh)	Advantages (A) and Disadvantages (D)
Flue gas recirculation (FGR)	<20%	Not Practical	N/A	A: Limits combustion temperatures D: Severe boiler erosion for ICAL design, and is not practical Limited space for ducting and recirculation fan. Fouling, tube corrosion
Selective non-catalytic reduction (SNCR)	30-50%	$20 - 50M	2.0 – 6.9 $/MWh	A: High reduction potential D: Very high opex Handling and storage of hazardous ammonia, and emissions to air of ammonia (slip) – i.e. creation of one air pollutant while controlling another
Selective Catalytic reduction (SCR)	80-90%	$100 - $315M	1.5 – 5.9 $/MWh	A: Very high reduction potential D: Extremely high capex / opex Large footprint required Handling and storage of hazardous ammonia, and emissions to air of ammonia (slip)

9. NO_x Control Feasibility Assessment at Vales Point

9.1 Overview

This section of the report considers the feasibility of implementing potential NOx mitigation measures identified and described in Section 8. In order to ascertain the feasibility of implementing these mitigating measures or controls, the key criteria considered were the material cost, retrofitting costs, O&M costs, timing, technology performance, emission reductions and engineering considerations.

9.2 Technical Feasibility

Table 9-1 evaluates the technical feasibility of each of the control options to achieve the 3 options for NOx control. Technical feasibility at this stage considers only the potential for the technology to achieve the various NOx levels. For the post-combustion controls, additional assessment would be needed to see if these could be implemented at Vales Point with respect to integrating with existing plant.

Table 9-1: Feasibility of NOx Mitigation Options

Base Case	Option i) 800 mg/Nm³	Option ii) 500 mg/Nm³	Option iii) <500 mg/Nm³	Comment
Unit 5 (current)	> 99%	No		Achieves 800 mg/Nm³ >99.6% of time, however with high CID and boiler efficiency loss. (Based on 2017-2021 data, with a maximum of 922 mg/Nm³ in 2021). Not possible to guarantee 800mg/Nm³ all the time.
Unit 6 (Current June - August 2021)	> 99%			32% reduction in NOx production, but increased carbon in dust (CID) to average 3.6%.[48] CID within accepted resale limits. Achieves 800 mg/Nm³ >99.7% of time, with maximum of 976 mg/Nm³ Not possible to guarantee 800mg/Nm³ all the time
NOx Control Mechanism	**800 mg/Nm³**	**500 mg/Nm³**	**<500 mg/Nm³**	**Comment**
Biomass Co-firing	No			NOx reduction potential has not been measured at Vales Point. Not a means of controlling NOx 100% of time to 800 mg/Nm³ but would reduce average NOx.
Burner optimisation for NOx control using air staging	Yes *	No		* Expected to reduced average NOx production, and % of time achieving 800 mg/Nm³, however it may not be possible to guarantee 800mg/Nm³ 100% the time

[48] Average of Morgan Ash Test Report Data for period 1/7/2021 to 21/8/2021, forwarded by VPPS on 24/8/2021

Base Case	Option i) 800 mg/Nm^3	Option ii) 500 mg/Nm^3	Option iii) <500 mg/Nm^3	Comment
Neural Network	Yes *	No		* To be confirmed by suppliers Expected to reduced average NOx production, and % of time achieving 800 mg/Nm^3, however it may not be possible to guarantee 800mg/Nm^3 100% the time
Low NOx burners *	Yes	Possibly **	No	* To be confirmed by potential non-OEM suppliers. OEM no longer supplies within Australia. ** may not be guaranteed for 100% of the time
Over-fire air (OFA)	No			Limited impact at VPPS, due to height of boiler. Not a means of controlling NOx to limits
Flue gas recirculation (FGR)	No			Physical gas path constraints mean additional gas flow not practical
Selective non-catalytic reduction (SNCR)	Yes	Yes		Ongoing additional operating cost and ammonia slip emissions which may include secondary nitrates which contribute to fine particle ($PM_{2.5}$) emissions, and other operational issues such as air heater fouling.
Selective Catalytic reduction (SCR)	Yes	Yes	Yes	Would be used only in conjunction with Low NOx burners Ongoing additional operating cost and ammonia slip emissions which may include secondary nitrates which contribute to fine particle ($PM_{2.5}$)

Of the above list of mitigation measures, five appear technically feasible to achieve the desired limits of at least 800 mg/Nm^3 and two appear potentially able to achieve 500 mg/Nm^3 or less. The cost implications of these options are discussed in **Section 9.3** below:

i. Burner optimisation for NOx control using air staging

ii. Low NOx burners (from non-OEM supplier, as GE no longer supply LNB in Australia)

iii. Selective non-catalytic reduction (SNCR)

iv. Selective Catalytic reduction (SCR)

v. Neural Networks technology

9.3 Cost Considerations

Table 8-3 sets out a basis for calculating costs associated with retrofitting potential NOx mitigation options, with costs determined as capital costs (capex) and operating and maintenance (O&M) costs.

There are some incentives for Delta to investigate means of reducing NOx, that is by the Load Based Licensing (LBL) fee mechanism. The LBL scheme sets limits on the pollutant loads emitted by holders of EPLs and links licence fees to pollutant emissions. Lower NOx emissions that may be achieved by the potential control measures identified by the PRS, would reduce the LBL fees payable.

The forecast annual NOx emissions and LBL fees over the remaining operation life of the power station are outlined in Table 9-2. Delta forecast the power station will cease operation in FY2029. The analysis below commences in the FY2021-22, which is the year the current Group 5 exemption expires.

Table 9-2 LBL Fee Forecast

Year	Generation (GWh)	tonnes NOx/GWh	Total NOx (tonnes)	LBL Fee ($/tonne)	LBL Fee ($)
FY 22	6,922	2.27	15,713	94.72	1,488,330
FY 23	6,624	2.27	15,036	96.71	1,454,178
FY 24	6,485	2.27	14,721	98.73	1,453,399
FY 25	6,226	2.27	14,133	98.73	1,395,353
FY 26	6,228	2.27	14,138	98.73	1,395,801
FY 27	5,973	2.27	13,559	98.73	1,338,651
FY 28	6,079	2.27	13,799	98.73	1,362,408
FY 29	5,512	2.27	12,512	98.73	1,235,333
Total	**50,049**	**2.27**	**113,611**	**97.98**	**11,123,454**

The generation data (GWh) is sourced from the latest Vales Point Power Station forecast model for period 2022 to 2029[49]. The tonnes of NOx emitted per GWh is based on the average NOx emission levels for Units 5 and 6 (post July 2021) with a small margin to cater for burner degradation (assumed 600 mg/Nm^3). The LBL fee ($/tonne) is calculated using the published regulation fee data as outlined in **Appendix E.**

[49] Delta issued Fuel Forecast Model June 2021 V5

Table 9-3 provides a further cost analysis of potential NOx mitigation or control options considered in **Section 9.2**. Total cost is capex for two units plus 2022-2029 opex.

Table 9-3 Cost Analysis of Potential NOx Controls Retrofitting

NOx Control Mechanism	Effectiveness (Max. emissions reduction potential)	Retro-fitting Capital Cost ($M/unit)	O&M Costs ($/MWh)	Generation U5&U6 MWh (2022-2029)	O&M Costs U5&U6 ($M)	Total Cost ($M) (Capex + 2022-2029 Opex) (1)	LBL Fees Saved ($M)
Burner Optimisation for NOx control using air staging	Up to 10%	6	0.05	50,049,000	2.5	14.5	1.117
Low NOx burners & OFA	Up to 50%	42	0.2	50,049,000	10	94	5.57
Selective non-catalytic reduction (SNCR)	50%	28	3.4	50,049,000	170.2	226.2	5.57
Selective Catalytic reduction (SCR)	85%	120	2.4	50,049,000	120.1	360.1	9.46
Neural Network	Up to 15%	3.0	0.012	50,049,000	0.6	6.6	1.67

Note: Maximum emission reduction potential is subjective and variable for retrofits projects. LBL fee is based on the lower NOx emission levels after the removal of the wide range burner tips from Unit 6 in June 2021.

(1) The total capital cost in 2017 report Table 8-3 incorrectly captured only a single unit capex as opposed to 2 units.

9.4 Summary

The NOx reduction measures outlined in Table 9-3 are cost prohibitive. However, NOx reduction measures which are feasible for implementation when considering both the technical and cost implications are:

- Combustion optimisation;
- Continued cofiring of up to 3% biomass.

The Neural Networks technology option with an associated closed-loop supervisory system is considered impractical pursuing at this stage of the boiler plant life, based on the following points:

- VPPS experiences and lessons learnt from the Siemens “neural network” system trial in 2010
- VPPS not adopting the “neural network” software-based technology in 2010
- The capex and opex costs for a modern “neural network” package integrated with the Siemens T3000 DCS and the associated closed-system supervisory system are prohibitive considering the time to implement the changes (i.e. plant will have to be in an outage)
- The limited remaining service life of the plant post new technology integration and testing
- Linking this advanced software-based technology to the basic combustion air control system in the Vales Point boilers, no supplier guarantees or notable gains in the NOx reductions will be offered.
- Reducing power generation demand from the power station as it approaches end of life.

The other listed NOx mitigation or control measures options in **Table 9-3**, and technically evaluated in **Section 8**, are not considered feasible primarily due to the total estimated costs for retrofitting far outweighing the saving in LBL (Load Base Licensing) fees that can be achieved. These high capex cost options to mitigate NOx cannot be accommodated by a utility nearing the end of its life. This expenditure is also not considered warranted considering the level of impact the power station has on ambient air quality in the regional area which was extensively evaluated in the Vales Point Power Station - EPL 761 Licence Variation Application Extension of Group 5 NO_X Emission Limit Exemption' report – Delta, Sept 2015. Summary findings from this report as relevant to this PRS are outlined in **Appendix C**. Another more recent study also found that at 5 locations around NSW, 1-hour average concentrations of NO_2 were good or very good throughout 2019.[50] This shows that additional NOx control measures are not required for NSW coal power plants in order to meet ambient air quality regulations.

One of the larger contributors to reducing NOx emissions (not listed in the table) will be the forecast reduced power generation output from the Vales Point site as the utility approaches the end of its service life.

[50] Lake Macquarie – Wyong Review of Annual Ambient Air Quality Data 2019 – Delta Electricity & Origin Energy, by Todoroski Air Services

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Appendix A. Vales Point Power Station Emissions and Controls

Vales Point Power Station utilises sub-critical pulverised coal technology, unitised boiler and steam turbine generators ("Rankine Cycle"), with single reheat. The coal is sourced from a variety of local mines, and more recently has been sourced from mines further afield, and transported by rail to site. Light oil (diesel) is used for boiler start-up, and when bringing coal mills into or out of service.

Vales Point Power Station is a 2 x 660MW pulverised coal fired power station. Units 5&6 were commissioned between 1978 and 1979 for base load operation. Vales Point was the first of the 660MW class utility power stations built in NSW, and uses sea water for condenser cooling in a once through arrangement.

The boiler is a forced circulation tower design, with tangentially fired twin furnaces, and backpass economisers and rotary airheaters. The boilers were originally fitted with electrostatic precipitators. The casings were reused for a fabric filters retrofit in 2012. The two units share a common stack. The steam turbines are of tandem compound, reheat, condensing design.

The major technical parameters are listed in **Table A-2** below:

Table A-2 : Vales Point Technical Parameters

Boiler	
Steam Flow	560 kg/s (2017 tph)
Main Steam Conditions	16.5 MPa / 541°C
Reheat Steam Conditions	4.1 MPa / 541°C
Furnace	Twin furnace, tangentially fired
Burners	1 burner in each furnace corner, 6 levels of burner nozzles (1 mill per level) Light oil ignition
Coal Mills	6 CE RP1003 Raymond Bowl Coal Mills
Turbine	
Toshiba	660 MW gross
HP	Single flow cylinder
IP	Double flow cylinder
LP	2 x Double flow cylinders
Feedheating	7 stages
Generator	
Toshiba	
Emissions Control	
Fabric Filters	Alstom
Coal Stockpiles	
Dry storage	35,000 t
Long term storage	1.6 Mt

Vales Point co-fires up to 3% woodchip, depending on availability of supply, and price of LGCs. The Wyee balloon loop allows rail deliveries of coal. Vales Point is also supplied with coal from a number of local mines.

Appendix B. Vales Point Power Station EPL Conditions (2016)

Conditions
L2 Load limits – None **L3 Concentration limits –** *Points 2 and 3 (Reference conditions: Dry, 273K, 101.3kPa. Oxygen correction: 7% O2. Averaging period: 1 hour)* - Cadmium: 100th percentile, 0.2 mg/m^3 - Chlorine: 100th percentile, 20 mg/m^3 - Fluorine: 100th percentile, 30 mg/m^3 - Hydrogen chloride: 100th percentile, 50 mg/m^3 - Mercury: 100th percentile, 0.05 mg/m^3 - Nitrogen Oxides: 100th percentile, 1500 mg/m^3 - Solid particles: 100th percentile, 50 mg/m^3 - Sulfuric acid mist and sulfur trioxide: 100th percentile, 100 mg/m^3 - Sulfur dioxide: 100th percentile, 1700 mg/m^3 - Type 1 and 2 substances in aggregate: 100th percentile, 0.75 mg/m^3 - Volatile organic compounds as n-propane equivalent: 100th percentile, 10 mg/m^3 **L3.5** - In addition to the concentration limits specified in condition L3.4 above, the following 99th percentile concentration limits apply for points 2 and 3 utilising the same units of measure, reference conditions, oxygen correction and averaging period as above for each pollutant listed below: a) nitrogen oxides: 1100 mg/m3; and b) sulfur dioxide: 1400 mg/m3. **L3.6** - For the purpose of condition L3.5 above, the 99th percentile concentration limit for nitrogen oxides does not apply to Boiler 6 until 1 January 2021. **L3.8** - For the purposes of nitrogen oxides at point 2 and 3 and in accordance with the Protection of the Environment Operations (Clean Air) Regulation 2010, Boilers 5 and 6 are taken to belong to Group 2 until 1 January 2022 or unless otherwise approved in writing by the EPA. **E3 Solid alternative fuel –** Solid alternative fuel may only be co-fired with coal and at a rate not exceeding five (5) percent by weight of the coal feed rate. The concentration of Type 1 & 2 elements and substances (as defined in the Clean Air Plant and Equipment Regulation 1997) in solid alternative fuel burnt in the power station, must not exceed 350 milligrams per kilogram.

Appendix C. Review of Existing Vales Point Reports

This Appendix provides a review of existing reports relating to Vales Point emissions regulation, management and control.

The following updates have been made in regards to the reports’ recommendations:

- Unit 6 wide range burner tips on replaced with conventional tips (April 2021) reducing U6 NOx. Unit 6 also had an overhaul in 2021. NOx emissions from Unit 6 have reduced substantially and emissions are now comparable on both units.
- A screening plant has reduced plastic contamination of coal, which had previously caused Mill classifier blockages
- Delta now has a procedure in place to detect PF line blockages using thermal imaging technology.
- Delta have conducted tests on air/fuel ratio with no significant improvement in NOx.
- Delta reports that while contamination still does occur with coal supplies, it is significantly reduced due to the installation of the screening plant.
- Delta are currently replacing secondary air damper actuators to improve control (to be completed by end of 2021).

<table>
<tr><th>Description /Main Findings</th><th>Relevance for NO_X PRS</th></tr>
<tr><td colspan="2">1) Improving Combustion Performance at Older Coal Fired Plant’ report – Alstom, 2002</td></tr>
<tr><td>Wallerawang and Liddell are ICAL designed tangentially fired boilers similar to Vales Pt.
Mt Piper is a Foster Wheeler designed wall fired boiler
<table>
<tr><th></th><th>Fly Ash</th><th>Bottom Ash</th><th>PF Fineness</th><th>NOx Performance</th></tr>
<tr><td>Wallerawang Historical UBC</td><td>11-14%</td><td>30+%</td><td>65%-75um</td><td>~400ppm</td></tr>
<tr><td>Liddell Historical UBC (similar design, different fuel).</td><td>5-7%</td><td>~15%</td><td>65%-75um</td><td>~450ppm</td></tr>
<tr><td>Mt Piper (different design, same fuel)</td><td>3%</td><td>7%</td><td>85%-75um</td><td>~650ppm</td></tr>
</table>
(The Mount Piper plant has a more softly rated furnace and longer residence time)</td><td>Tangential firing produces lower NOx than wall firing.
Increased PF Fineness appears to increase the intensity of the flame (thermal NOx).
ICAL designed boilers have a high furnace volumetric rating, leading to low residence time and high carbon in dust levels.</td></tr>
<tr><td>To maintain CID levels at a minimum, without increasing NOx requires a higher furnace volume and residence time.</td><td>Vales Pt units furnace volume is fixed, and NOx improvements with the current unit configuration will increase CID.</td></tr>
<tr><td>Wallerawang made changes to the burners (Wide Range Tips and primary air reduction) on Unit 8 to initiate combustion earlier to reduce CID.
The burner design life was shortened, with a cost impact</td><td>Changes to operation are possible with the existing boiler design,</td></tr>
</table>

<table>
<tr><th>Description /Main Findings</th><th>Relevance for NOx PRS</th></tr>
<tr><td>
Boiler turndown was improved to 30%
<table>
<tr><th></th><th colspan="2">Ash UBC Performance</th><th>NOx Performance</th><th>Lowest Load with coal only stable combustion</th></tr>
<tr><th></th><th>Flyash</th><th>Bottom Ash</th><th></th><th></th></tr>
<tr><td>Actual pre-conversion</td><td>8.6%</td><td>30+%</td><td>~400ppm</td><td>60%</td></tr>
<tr><td>Actual post conversion</td><td>3.8%</td><td><5%</td><td>~420ppm</td><td>30%</td></tr>
</table>
</td><td>
which reduces CID with only marginal change in NOx.

Note: VP coal may not permit replication of WW results.

VP performance (3.5%CID, 37% min load) is similar to improved WW performance, so there is less room for improvement at VP.
</td></tr>
<tr><td>
A review of WW’s design revealed inconsistency of pulveriser performance, and unequal distribution of air and coal between individual corners.

Intensive combustion with consequent high thermal NOx production may occur with high levels of primary air. Poor PF fineness will contribute to unstable combustion, and high CID.
</td><td>
Similar inconsistency may be occurring at VP. PF fineness, and primary air distribution should be confirmed by testing at VP.
</td></tr>
<tr><td colspan="2">2) ‘Vales Point Power Station Unit 6 NOx & Unburnt Carbon Tuning (Post Wide Range Tip Installation)’ – Alstom, September 2013</td></tr>
<tr><td>
Wide Range burner tips were fitted to VP6 in 2012 which:
• improved CID and turndown
• increased NOx emissions 300 to 350 ppm (contrary to supplier assurances of minimal impact on NOx)

VP6 CEMS was replaced 25/9/2013, which showed 500-600ppm NOx levels (higher than VP5 with standard burners)

In light of the Alstom recommended combustion tuning, and also confirmation of the calibration of both CEMS
<table>
<tr><th>Power Station</th><th>UBC Reduction (approx.)</th><th colspan="2">WRT effect on unit turndown (Low Load Point)</th><th colspan="3">NOx Level [ppmv] (approx.)</th></tr>
<tr><th></th><th></th><th>Before</th><th>After</th><th>Std Tips</th><th>Post WRT retrofit (pre-tuning)</th><th>Post WRT retrofit (post-tuning)</th></tr>
<tr><td>Collinsville</td><td>60%</td><td>80%</td><td>40%</td><td>300</td><td>390</td><td>300</td></tr>
<tr><td>Wallerawang</td><td>60%</td><td>50%</td><td>30%</td><td>400</td><td>420</td><td>Not required</td></tr>
<tr><td>Liddell</td><td>50%</td><td>Not tested</td><td>Not tested</td><td>Data not available</td><td>350</td><td>Not required</td></tr>
<tr><td>VP6 original CEMS</td><td rowspan="2">48%</td><td rowspan="2">Not tested</td><td rowspan="2">Yet to be tested</td><td>300</td><td>350</td><td>CEMS decommissioned</td></tr>
<tr><td>VP6 new CEMS</td><td>not measured</td><td>500 - 600</td><td>Yet to be tuned</td></tr>
</table>
</td><td>
NOx levels increased with wide range burner tips, but CID decreased 50%. As such, NOx levels would reduce to levels similar to VP5 if the burners reverted to conventional design, however CID would increase.

Combustion tuning is recommended to provide reduction in NOx. This was completed in 2015 to little effect
</td></tr>
</table>

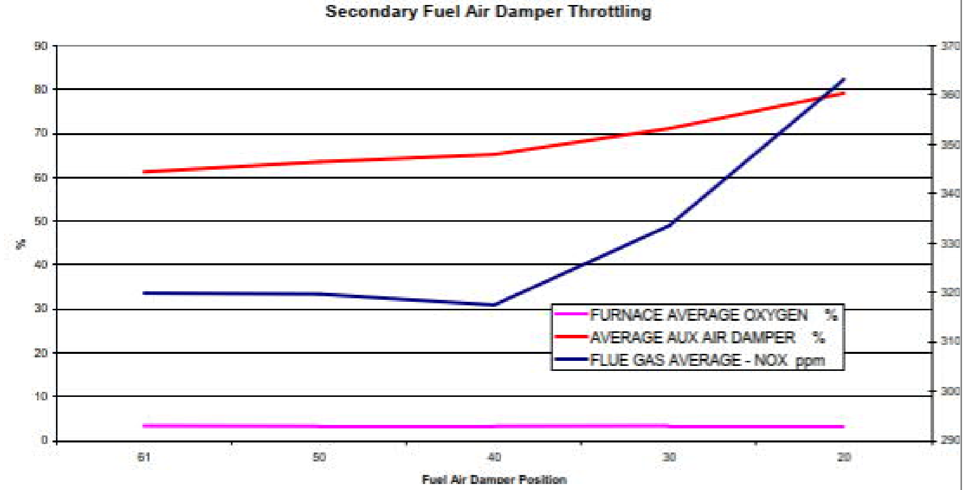
Description /Main Findings	Relevance for NO_X PRS
3) 'Vales Point Power Station Units 5 and 6 Combustion Analysis Report' – Robert Ironside & Associates, April 2015	
1. High carbon in dust (CID) on both units, but particularly on Unit 5; 2. High oxides of nitrogen (NOx) on both units, mostly on Unit 6; 3. Ash fouling in the economiser in both units; 4. Low main and reheat steam temperatures on both units; 5. High fabric filter inlet temperatures; 6. Uneven flue gas oxygen levels between each furnace of each unit, however Unit 5 did not have variations in NOx between furnaces; 7. Mill classifier blockages on both units. 8. Decreasing primary airflow decreases NOx (longer term this change led to mill problems and roping in PF pipes). 9. Combustion tuning completed based on flue gas O_2 10. Notable limitations from the undersizing of the boiler furnace	
4) 'V500781 Burner Upgrade Financial Evaluation White Paper' – Delta, March 2014 (Obj. ID: D1095902)	
The reduced burner primary airflow, achieved by increasing the fuel air ratio from 1.0 to 1.2 has resulted in a reduction in NOx generation and it may have resulted in an improvement in hot reheat steam temperature with no adverse effects observed on any other parameter. Hence, it is recommended that the fuel air ratio be increased from 1.0 to 1.2 on both units and for the operation to be monitored over a two-month period.	
Increasing burner tilt angle increased both NOx and hot reheat steam temperature, although a positive effect on steam temperature was not apparent at the low and high limits of the tilt range. It is recommended that the tilt angle be limited in range from a low of -5° to a high of 12°. This will reduce any observed windup in the control system and will also reduce the adverse effects on NOx with high burner tilt.	Examine feasibility of lowering NOx at the expense of low reheat and steam temperature, which will decrease plant efficiency. (A reduction in steam temperature or reheat temperature by 10°C will reduce plant efficiency by approximately 0.5% each)
The performance of Unit 5 is generally better than that of Unit 6. This may be due to the different burner tip design between the units and/or the difference in windbox to furnace differential pressure set points. Unit 5 has a higher set point, which is thought to provide a better velocity ratio between fuel air and primary air and, therefore, better mixing of the fuel and air as they enter the furnace. Hence it is recommended that the windbox to furnace differential pressure set point on Unit 6 be increased to that of Unit 5 at 1.2kPa.	
The furnace imbalance tests showed that… there was some difference within the furnaces, particularly on Unit 6.	Inconclusive as to effect on NOx.

Description /Main Findings	Relevance for NO_X PRS
	Unit 6 NOx is now balanced
Low levels of CO measured throughout all tests suggest that it may be possible to reduce combustion excess air. This would increase residence time and may reduce both CID and fabric filter inlet temperatures. Recommended that a series of tests be conducted with reduced excess air while monitoring CO, CID, NOx and fabric filter inlet temperatures	Turning was completed and O_2 levels dropped from 3.5% to 3.2%
Consideration should be given to installation of on-line CO analysers in the flue gas ducts upstream of the air heater, with a view to using measured CO to optimise excess air.	Ditto
Plastic contamination of the mill and fuel pipes is unavoidable, but it should not increase in frequency with a reduction in primary airflow. If plastic contamination is likely to lead to a partial loss of unit availability then the installation of a facility to remove the plastic should be considered.	Screening plant installed with noticeable improvement
5) Reduction via overfire air - Feasibility of use of unused sootblower ports in boiler windbox' – Aurecon, July 2015 (Obj. ID: D1260214)	
There are 22 unused sootblower openings above the top burner level could be used for inserting Over Fire Air, but is only 1.9% of secondary air flow. US research (EPRI) using modelling coal fired furnaces was extrapolated, and reportedly 10% NOx reduction could be achieved	<2% airflow would be unlikely to have a measureable improvement.
Alternate options for NOx reduction include:	
Retrofit of purpose designed and located over fire air ports. The Vales Point windboxes are ideally placed to allow a separated OFA system to be implemented. The major expense items would be the waterwall penetrations and a damper system to allow control of the OFA.	Greater potential for NOx reduction than sootblower ports (% reduction not specified in Aurecon report), but significant capital costs due to rearranging pressure parts around penetration.
Explore options with GE and other suppliers. Boiler and burner suppliers such as Babcock, Siemens ABT, BHI Foster Wheeler and MHI all provide burners for tangentially fired boilers	Greater potential for NOx reduction (% reduction not specified in Aurecon report), but significant capital costs due to new Low NOx burners.
6) 'Combustion Working Group - Carbon in Dust Investigation August 2015 & Action Plan' – Delta, September 2015 (Obj. ID: D1261808)	
This paper is focused on means to reduce the carbon in dust (CID) which is essentially unburnt fuel in the ash. Generally CID is inversely proportional to NOx, such that controls decreasing NOx will increase CID and vice versa. CID can be lowered through more intense combustion, but leads to higher temperatures increasing thermal NOx.	Combustion consistency will reduce NOx. Measures include position feedback on

Description /Main Findings	Relevance for NO_x PRS
However inconsistent combustion performance will lead to both high CID and NOx emissions. Inconsistent combustion is generally a result of poor control over air, and coal grind fineness, PF pipe blockages due to coal mine plastic contamination. This will result in some areas being starved of combustion air, while others are over aired, and fuel rich vs lean zones. Measures to improve combustion consistency will also improve CID and NOx.	secondary air dampers, monitoring.
Biomass cofiring is said to increase CID. The main evidence is higher mill motor current when firing cofiring biomass. The addition of biomass will therefore decrease coal fineness. There is no evidence biomass would increase NOx levels. The lower nitrogen content and higher moisture content of biomass should reduce combustion temperature and therefore NOx emissions. Concerns with impact on mills could be mitigated through additional size reduction prior to mixing with coal.	Investigate pre-sizing biomass (etc) to limit negative impact on coal mills. Biomass quantities are small,
7) 'Vales Point Power Station - EPL 761 Licence Variation Application Extension of Group 5 NOX Emission Limit Exemption' report – Delta, Sept 2015 (Obj. ID: A660385)	
This report was prepared by Delta to support their application for a revision of Environmental Protection Licence (no. 761), to continue their exemption to comply with Group 5 emissions standards. The report has been submitted and accepted by the EPA, on the basis that a Pollution Reduction Study (PRS) is prepared to investigate the viability of further NO_x controls at Vales Point.	
<u>Relatively low concentrations of NO_2 and SO_2 measured in ambient air</u> Ambient air quality concentrations in the surrounding region are generally considered low against the air quality criteria for NO_2 and SO_2. Delta suggests that further controls applied for these pollutants at Vales Point would provide negligible additional benefits to local and regional air quality. Specifically the report reviews the Lake Macquarie Wyong Air Quality (LMWAQ) reports published by NSW EPA (2013 – 2015) which conclude air quality on the Central Coast is generally considered good with respect to NO_2 and SO_2, presenting data for the Wyong monitoring station in the report. The NO_2 concentrations measured that the Delta Ambient Air Monitoring Station (AAMS) have always been below the ambient air quality criteria.	Recent data from Wyong Air Quality Index (EPA, 2016) during 2014 and 2015 was reviewed and it was noted that the most recent air quality in this region was poor (1% of time in both 2014 and 2015) and fair (5% in 2014, 3% in 2015) on some occasions, and good or very good for the remainder of the time.
<u>Recent reduction in NO_x sources in the region</u> Sources of NO_x in the local air shed were reviewed for National Pollution Inventory (NPI) for 2008/2009 and 2014/2015. The contribution of electricity generation pollution sources in the Lake Macquarie and Wyong local government areas decreased by 40% between these reporting years because of the closure of Munmorah power station in 2012 (reduction of ~6,000,000 kg of NO_x / annum), also operated by Delta. Further reductions were exhibited at Delta because of reduced electricity demand across the market (estimated as 2,000,000 kg NO_x / annum). Delta acknowledges the increase in NO_x emissions measured following the upgrade to the Unit 6 burner in 2013 which offsets the reduction of emissions as a result of	The reduction in NO_x emissions from reduced electricity demand have not been realised because of the increase in NO_x exhibited following the burner upgrade. Further consideration of the reports and data associated with the increase in emissions

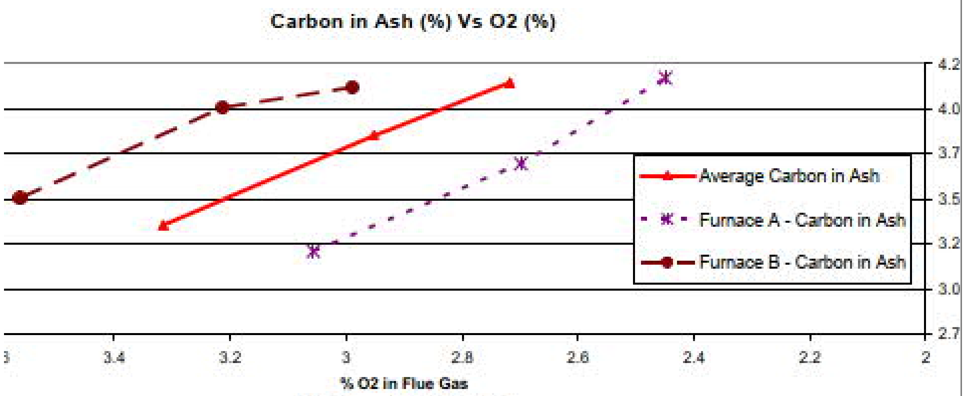
Description /Main Findings	Relevance for NO_x PRS
reduced demand. The upgrade to the burner resulted in plant efficiency gains, improved plant performance at low loads and reduced carbon in ash but the increase in NO_x concentrations has not be explained definitively following investigation and testing by Delta and the supplier Alstom.	following the burner upgrade will be conducted as part of this review.
<u>**Dispersion modelling study finds current emission limit of 1,500 mg/m^3 acceptable**</u> A dispersion modelling study (Wiebe & Castillo, 2010), validated by monitoring data collected at Wyee, demonstrated that the operation of Vales Point under existing conditions with an emission limit of 1,500 mg/m^3 of NO_x would not cause significant environmental harm. Meteorology from 2004 was used in the assessment. Delta considers the modelling assessment to be conservative because the background air quality included Munmorah as a source and did not equate for recent upgrades to Eraring power station.	The modelling study was finalised in 2010 and generally adopted a conservative approach in keeping with established NSW guidelines and modelling processes.
<u>**Cost / benefit analysis finds further controls prohibitively expensive**</u> Average operating conditions for NO_x emissions at Values Point typically meet the Group 5 limit of 800 mg/m^3. Delta would like to maintain the current 1,500 mg/m^3 NO_x emission limit to maintain a margin for compliance for conditions which result in above average emissions. Applying emission reduction controls to meet the 800 mg/m^3 limit for the infrequent occurrence of higher emissions have been determined to be prohibitively expensive by Delta. Delta suggests that any formal evaluations of these costs and emissions reductions would need to be guaranteed by the manufacturer.	The aim of this PRS will be to provide an evaluation of the costs and benefits of available and feasible technologies to inform this finding.
<u>**LBL scheme incentivises feasible emission reduction techniques and technologies**</u> Delta is incentivised by the Load Based Licencing (LBL) scheme to investigate and identify opportunities for improvement to reduce NO_2 and, if practicable and economically viable, implement these options. Delta estimates the additional NOx load-based licence fees incurred by on Unit 6 of the new burners is approximately $500,000 - $600,000 per annum.	A business case to reduce emissions is already in place for Delta so if options are feasible they are likely to be adopted.
8) Vales Point NOx Reduction, Draft Secondary Air Tuning Test Report – Aurecon December 2010 (Report Ref 206272)	
The results presented show that initially as the secondary fuel air dampers are closed, a small reduction in the NOx emissions is evident reaching a minimum at a damper position of 40%. This effect however, was reversed beyond 40% throttling, and the trend results in a rapid increase in the nitrogen oxide production. This increase in NOx emissions at throttle positions of 30% and 20%, also resulted in a greater split in the combustion properties between furnace A and B of Unit 6. The resulting increase in NOx emission when the fuel-air dampers were throttled beyond 40% was unexpected. A possible explanation of the observed behaviour is that when the secondary air fuel velocity is reduced beyond a certain level, the resulting velocity difference with the primary air/fuel stream produces a shear region with high turbulence. This turbulence promotes rapid mixing of the PF and air, thereby increasing NOx production.	Secondary Air Fuel damper positions of 40% appeared to be optimum.

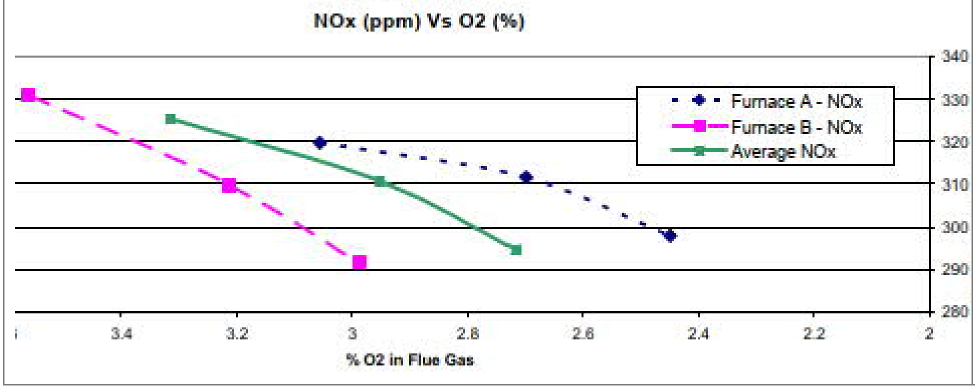
Description /Main Findings	Relevance for NO_X PRS



A reduction in the excess available oxygen, the O_2 set point, corresponds to a reduction in the NOx emissions. The figure also illustrates the difference between the A and B sides of the Unit 6 boiler. The reason for this is outside the scope of this report however imbalances in PF distribution and secondary air distribution are likely contributors.

In addition to the nitrogen oxide relationship with O2 levels, there is an inverse relationship between excess oxygen and unburnt carbon in ash.





A reduction in NOx emissions of almost 10% was achievable with a reduction in flue gas O2 from 3.3% down to 2.7%.

However, this increased the carbon in ash to between 3.7 and 4.1%. Since the limit for carbon in flyash which can be sold to cement produces ranges from 3.5-4.5%, this may restrict the ability of Vales Point to recycle flyash.

Appendix D. Vales Point CEMS Data 2017-2021

Unit 5	Operating	Min NOx 5A	Max NOx 5A	Ave NOx 5A	Min NOx 5B	Max NOx 5B	Ave NOx 5B	Ave NOx Unit-wide	Ave Load	% NOx meas. >800mg/Nm^3
	Hours	mg/Nm^3	mg/Nm^3	mg/Nm^3	mg/Nm^3	mg/Nm^3	mg/Nm^3	mg/Nm^3	MW	mg/Nm^3
2017	6241	347	1075	588	305	1035	592	591	512	0.2%
2018	6268	325	1018	616	348	974	620	621	517	1%
2019	7508	312	932	651	304	914	596	624	514	1%
2020	7011	300	1245	585	302	1045	635	611	470	1%
2021	5120	300	812	529	329	922	647	589	485	0.0%

Unit 6	Operating	Min NOx 6A	Max NOx 6A	Ave NOx 6A	Min NOx 6B	Max NOx 6B	Ave NOx 6B	Ave NOx Unit-wide	Ave Load	% NOx meas. >800mg/Nm^3
2017	6220	337	1184	809	310	1147	762	786	498	46%
2018	7463	339	1507	831	324	1365	846	840	540	64%
2019	7390	332	1071	766	338	1149	816	791	523	48%
2020	7494	313	1132	707	341	1262	774	741	490	28%
Jan-Apr 2021 (WR burner)	2249	384	940	665	313	1070	721	693	416	15%
May-Aug 2021 (conventional)	1086	259	740	513	188	976	551	532	473	0.3%

Appendix E. Calculations and Data For Load Base Fee

Ref. Email from Shannon dated 19/8/2021
https://www.epa.nsw.gov.au/licensing-and-regulation/licensing/environment-protection-licences/load-based-licensing/calculating-pollutant-load-fees
load-based-licensing-overview-150399.pdf

Load bases fees are calculated using and EPA formula where the inputs are:

- **Assessable Load (AL)** - for VPPS the *actual load* is used, not a discounted weighted load. Annual mass of emissions in kg/Tonne
- **Pollutant Weighting (PW)** - - fixed value of 9 for NOx emissions
- **Critical Zone (CZ)** - YPPS is located in regional area, not within the Sydney basin area critical zone. Summer months weighting not applicable. Critical zone weighting 2
- **Pollutant free unit (PFU)** - the dollar cost which for the 2020-2021 reporting period is $51.54 and increases yearly per the below table.

Note that FRT was not included in the assessment as the power production shall be decreasing and the Unit 6 NOx emissions with the removal of the wide range burner tips and installing conventional burner tips have reduced the NOx emission by 32%.

Based on these inputs, the load base fee is calculated and listed in the revised Table 9-2.

For the period 2022-2029:

- The *coal fired generation* is sourced from the document "Fuel Forecast Model June 2021 V5 Jacobs"
- The average NOx emission (corrected to 7% O_2) is **570** mg/Nm^3 (unit 5 & 6 combined). This is based on Unit 6 data post the burner modifications in May-June 2021. A value of **600** mg/Nm^3 is used in the tables to accommodate burner degradation.
- FY22 is from July of 2021 to June 2022

PFU for each year is outlined in the Protection of the Environment Operations (General) Regulation 2009 (Chapter 2, Part 1, Division 3, Clause 19) and is capped at $54.85 after 1 July 2023.

(l) on or after 1 July 2020 and before 1 July 2021—$51.54,

(m) on or after 1 July 2021 and before 1 July 2022—$52.62,

(n) on or after 1 July 2022 and before 1 July 2023—$53.73,

(o) on or after 1 July 2023—$54.85.

AL x PW x CZ x PFU/10 = $/tonne NOx

AL	PW	CZ	PFU	Fee
	9	2	$52.62	$94.716
	9	2	$53.73	$96.714
	9	2	$54.85	$98.73