Combustion Turbine NOx Control Technology Memo

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Purpose

This report summarizes the available nitrogen oxides (NOx) control technologies available for natural gas combustion turbines, including natural gas combined cycle (NGCC) and simple cycle facilities. These technologies are generally divided into two categories: combustion controls and post-combustion controls. Combustion controls reduce the amount of NOx generated in the turbine combustion process and include water injection and dry and ultra-low NOx (ULN and DLN) systems. Post-combustion controls remove NOx from the exhaust gas and includes selective catalytic reduction (SCR).

The following sections provide a brief background of NOx emissions, description of the technologies, a summary of its applicability in various combustion turbines, a typical range of performance, and a cost summary for a sample combustion turbine facility.

NOx Background

There are two mechanisms by which NOx is formed in turbine combustors; fuel NOx and thermal NOx. Fuel NOx is formed by the reaction of nitrogen bound in the fuel with oxygen in the combustion air. Natural gas typically does not have a high nitrogen composition; thus, fuel NOx is not the dominant source of NOx in natural gas fired facilities. Thermal NOx formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form NOx. The major contributing chemical reactions occur in the high temperature area of the gas turbine combustor and NOx formation increases with spikes in temperature and residence time.

There are several compounds that NOx represents, but NO and NO_2 are the most prevalent compounds found in combustion turbine exhaust. The use of duct firing in combined cycle facilities also adds to the total amount of NOx emissions generated. The majority of emissions from combustion turbines at full load are in the form of NO, however, NO is converted to NO_2 in the atmosphere to form ozone (O_3). Additionally, the use of oxidation catalyst for carbon monoxide (CO) control can increase the NO_2 ratio, by oxidizing NO to NO_2.

Water & Steam Injection

Description

Water and steam injection have been used since the 1970’s as a means of controlling NOx emission from combustion turbines. Inside the combustion turbine, fuel rich zones that create high flame temperatures are the result of the simultaneous mixing of fuel and air and their subsequent combustion. Injecting water or steam into the flame area of the combustor provides a heat sink that lowers the combustion zone temperature and reduces thermal NOx formation. As noted earlier in the report, as the combustion zone temperature decreases, NOx production decreases exponentially. Water used in this process must be of high quality (e.g. demineralized water) to prevent deposits and corrosion from occurring in the turbine. While many combined cycle facilities may have existing demineralized water treatment on site, existing simple cycle facilities often do not. In those cases, there is the option to build or rent new water treatment equipment or have high quality water delivered to site.

Water is more efficient for reducing the flame temperature than steam, as the energy required to vaporize the water creates a larger heat sink. Generally, the steam flow required is 1.5-2 times the amount of water required for given NOx reduction. Water and steam injection systems are designed to a specific “water-to-fuel ratio” (WFR) which has a direct impact on the controlled NOx emission rate and is generally controlled by the turbine inlet temperature and ambient temperature.

As combustion turbine designs are developed with higher firing temperatures to increase thermal efficiencies, higher water injection rates are required to control NOx emissions. However, points are reached where the amount of water and steam injected begins to create several design issues that must be considered. As water is injected at higher rates to further reduce NOx emissions, the thermodynamic efficiency of the combustion turbine will decrease, seen as an increase in heat rate, due to the energy required to turn the water into steam; however, depending on the overall mass flow being added, there is a potential to break even on total power generated. In addition, higher water and steam injection rates can cause an increase in the dynamic pressure activity in the combustor which can cause wear and tear within the combustion turbine. As the addition of water and steam creates thermodynamic inefficiencies in the combustion process, higher levels of carbon monoxide production are commonly seen. The rate of carbon monoxide production increases as the amount of water and steam injected increases. Overall, water and steam injection create a dichotomy due to the need for facilities to inject higher water and steam rates to meet lower NOx emission limits, exacerbating the problems associated with increased injection.

Applicability and Typical Performance

Water injection is a well-established technology and modern technology can offer NOx emissions of below 42 ppm (0.05 lb/mmbtu), with the lowest practical emissions of 25 ppm (0.03 lb/mmbtu).[1] Compared to other NOx emission control technologies, water injection may have a lower capital cost, but higher variable costs. This makes water injection especially attractive for peaking combustion turbines or other units that operate infrequently. It is most often applied to smaller frame turbines (e.g. GE LM series of aeroderivatives), rather than the modern large-frame heavy duty turbines (>200 MW) that have been installed since 2010; generally water injection has been superseded by other technology for combustion based NOx control on heavy-duty turbines (see DLN section). The high variable cost is partly due to the quality of water that is required for injection, which not every plant has excess capacity to meet, especially simple cycle facilities, thus facilities with water limitations would not be well suited for water injection. While there may be scenarios where water and steam injection would be more attractive than other control technologies, injection can be added to both new combined cycle and simple cycle facilities, as well as retrofitting existing units. This control method is one of the most historically used technologies to reduce NOx emissions. In addition, water and steam injection can be combined with post combustion control technologies such as SCR systems to further reduce NOx emissions.

Dry Low NOx (DLN) And Ultra-Low NOx (ULN) Burners

Description

DLN combustor technology premixes air and a lean fuel mixture prior to injection into the combustion turbine that significantly reduces peak flame temperature and thermal NOx formation. Conventional combustors are diffusion controlled where fuel and air are injected separately. Combustion occurs locally at stoichiometric interfaces resulting in hot spots that produce high levels of NOx. In contrast, DLN combustors generally operate in a premixed mode where air and fuel are mixed before entering the

[1] GE Power Generation, Schorr, M. M., & Chalfin, J. (1999, September). *Gas Turbine NOx Emissions Approaching Zero – Is it Worth the Price?* (GER 4172). General Electric Power Systems. https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/resources/reference/ger-4172-gas-turbine-nox-emissions-approaching-zero-worth-price.pdf

combustor. The underlying principle is to supply the combustion zone with a completely homogenous, lean mixture of fuel and air. DLN combustor technology generally consists of hybrid combustion, combining diffusion flame (for low loads) plus DLN flame combustor technology (for high loads). Due to the flame instability limitations of the DLN combustor below approximately 50 percent of rated load, the turbine is typically operated in a conventional diffusion flame mode until the load reaches approximately 50 percent. As a result, NOx levels rise when operating under low load conditions. For a given turbine, the DLN combustor volume is typically twice that of a conventional combustor. ULN technology is a further development of DLN technology that uses similar combustor designs to achieve enhanced fuel/air mixing that allow for even further reduction in NOx emissions.

Applicability and Typical Performance

DLN and ULN systems are an attractive option for most combustion turbines due to the lower fuel nitrogen content in natural gas. They offer the potential for substantial reduction of NOx from turbines, as well as improved performance when compared to water injection. Depending on the frame size, these systems can achieve baseline NOx emissions of 9-15 ppm (0.01 – 0.018 lb/mmbtu) for DLN and as low as 5 ppm (0.006 lb/mmbtu) for ULN. However, the combustor design for DLN and ULN systems is typically larger than conventional types, and space may not be available in older turbines for the upgrade. DLN combustors also can be limited in wider operating ranges than conventional combustors. Gas facilities that are expected to cycle on a regular my experience spikes in NOx emissions due to the nature of how the technology performs at lower loads.

DLN / ULN capital costs vary with the size of the turbine and the specifics of the particular turbine being retrofitted. Baseline NOx level will also significantly affect the estimate of cost per ton of NOx reduced. DLN and ULN technologies are applicable to both combined cycle and simple cycle units, and are a developing technology that is being included in new facilities design to help meet ultra-low emission requirements along with being an attractive option for existing facilities that have the available space to accommodate the upgraded combustors. Similar to water and steam injection systems, DLN and ULN can be used in combination with post combustion technologies such as SCR to meet even lower emission rates at the stack.

Selective Catalytic Reduction (SCR)

Description

Selective catalytic reduction (SCR) is the most widely used treatment for a gas turbine and typically required on new installations as part of the Best Available Control Technology (BACT) evaluation results. SCR is a process in which ammonia reacts with NOx in the presence of a catalyst to reduce the NOx to nitrogen and water. The catalyst enhances the reactions between NOx and ammonia, according to the following reactions, but must be within a specific temperature window:

$$2\ NO + 2\ NH_3 + \frac{1}{2}\ O_2 \rightarrow 2\ N_2 + 3\ H_2O$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Note that for high NOx reduction, ammonia is typically injected at higher than a 1.0 stoichiometric ratio of ammonia-to-NOx removed; this results in ammonia slip. Systems design is therefore balanced to ensure NOx reduction is maximized while ammonia slip is minimized.

For an SCR system, multiple reagents may be used, including anhydrous ammonia, aqueous ammonia (19% and 29%), and ammonia generated from urea conversion. This process requires additional equipment to store, vaporize, dilute, and mix the reagent prior to being injected into the system through the ammonia injection grid (AIG). The SCR reactor is located downstream of the combustion turbine itself, and in the case of a combined cycle facility with a heat recovery steam generator (HRSG), it is located within the tube banks at an appropriate temperature region. The typical temperature window for this process is roughly 600-750°F. The most widely used SCR catalyst is formulated with titanium oxide (TiO_2) as a base substance and vanadium pentoxide (V_2O_5) as the active component. Other compounds, such as tungsten oxide and silicon oxide, are added for strength or thermal resistance. Unlike with coal-fired applications, the catalyst used is typically stacked vertically with gas flow horizontally through the catalyst face, has a much smaller pitch due to the limited particulate and plugging concerns, and does not deactivate as rapidly due to minimal catalyst poisons in the flue gas.

Applicability and Typical Performance

SCR systems are used throughout the power industry as a NOx control technology and developments in catalyst technologies have allowed for broader implementation of the process. Almost all new combustion turbine facilities, whether simple cycle or combined cycle, require an SCR system in conjunction with a combustion technology (DLN or water/steam injection) in order to meet stringent NOx emission rates. Based on data from the Clean Air Market Database (CAMD), 80% of combined cycle facilities implement an SCR system compared to 10% of simple cycle units. A combination of SCR with combustion control technologies can achieve levels as low as 2 ppm (0.002 lb/mmtbu) of NOx with 2-5 ppm of ammonia slip, which is currently considered Lowest Available Emission Rate (LAER) for combined cycle units.

Typically, SCR systems are installed in combined cycle applications downstream of the high-pressure steam tubes section due to temperature impacts on the reaction process. However, developments in low and high temperature SCR systems have made installations of SCR systems more widely possible. High temperature catalyst (>800°F), which includes more precious metal composition, can be used on simple cycle systems downstream of the turbine; however, in most applications, a reactor is built with tempering air to utilize typical catalyst temperature composition.

Existing combined cycle facilities with SCR units in place that are looking to further reduce NOx emissions need to understand available space inside their reactor for extra catalyst volume or activity. For combined cycle facilities originally built without SCR, if extra space in the HRSG was not dedicated for the future AIG and catalyst, it may be impossible to retrofit the facility with SCR. Simple cycles units looking to add an SCR unit would see high costs as well due to either the use of a high temperature system that can be placed immediately downstream of the combustion turbine, or a larger SCR reactor that would require tempering air. Either way, duct or stack expansion is required to make an appropriate reactor with decreased flue gas velocity through the catalyst.

As noted above, temperatures of the flue gas and in the SCR play a major role in performance. Temperature requirements dictate the location of where an SCR system is placed within the duct path in order to maintain efficiency of the reactions. Facilities that expect to operate at or near full load will have constant temperatures along the flue gas path, however, cycling units will experience large temperature swings of the flue gas decreasing the reaction kinetics inside the SCR. Below the catalyst design temperature window (typically around 50-60% load), ammonia injection must cease, which may alter the facility’s ability to meet NOx emissions rate at low load. As such, the SCR system design temperature typically dictates the minimum emission compliance load.

Other impacts to the existing facility operation with retrofitting an SCR would be impact to the overall turbine backpressure. Adding a new catalyst bed can add around 4 in.w.c. of pressure drop to the system, causing backpressure to the combustion turbine. This results in a nominal increase to the performance and heat rate of the turbine.

Combustion Turbine Emission Control Summary

The following table provides a qualitative summary of the technologies described in the above sections when reviewing its applicability towards new and existing facilities.

Table 1 – Control Technology Considerations

Control Technology	New Facilities	Existing Facilities (Retrofit)
Water / Steam Injection	- Common system installed historically on small frame turbines. - Requires high quality water for injection. Facility must have available water treatment system. - Due to higher operating costs / lower capital, attractive option for peaking or cycling operation. - Can be used in conjunction with SCR.	- Can be retrofitted to majority of existing facilities (combined or simple cycle). - Similar water considerations. - Similar operational considerations.
Dry / Ultra Low NO_x	- Common system installed in new facilities. - Can be used in conjunction with SCR.	- Can be retrofitted to majority of existing facilities, however, turbine must have available space for new combustors as they are larger than conventional type.
Selective Catalytic Reduction	- Common system installed in new facilities, especially in HRSGs. - Can be used in conjunction with Water/Steam Injection or DLN / ULN systems to achieve BACT or LAER limits.	- Hard to retrofit on NGCC if extra HRSG space was not provided initially. - Requires separate reactor for simple cycle applications that are very costly.

Sample Unit Cost Estimate Summary

To further evaluate the NOx reduction technologies described in the above sections, order of magnitude costs were developed for two potential configurations: a sample simple cycle peaker SCR retrofit and a sample NGCC SCR retrofit. The following section provides a cost summary of the technologies when retrofitting an SCR system outlined in Table 2 below. Project costs account for direct costs of a complete NO_x control system along with general conditions, and project indirect costs. The cost estimate is based largely on Sargent & Lundy LLC experience on similar projects. Detailed engineering has not been performed, and specific site characteristics other than those listed in Table 2 were not taken into consideration. The estimate includes but is not limited to the following scope;

- Direct Costs
  - Material / Equipment and Labor
    - Civil / Structural / Architectural
    - Mechanical Equipment, Piping, Valves, Insulation

- Electrical equipment
- Instrumentation and controls

- General Conditions
  - Additional labor costs, site overhead and other construction indirects
- Indirect Costs
  - Engineering, construction management support, startup/commissioning, contingency.

Operating and maintenance (O&M) costs are also provided in Table 3. Costs are based on fixed costs associated with labor and variable costs associated with utilities, water, reagents, and catalysts as required for operation of the specific control system on an annual basis along with any performance impacts to the plant output. The capacity factor of the facility is accounted for in the order of magnitude cost.

Table 2 – Sample Unit Information

Parameter	Units	Example 1	Example 2
Facility Type		Simple Cycle Combustion Turbine	Natural Gas Combined Cycle
Output	MW	50 MW Turbine	90 MW Turbine
NOx Emissions	lb/mmbtu	0.15	0.05
	ppmvd @ 15% O_2	~40	~13
Capacity Factor	%	15 (during ozone season)	65
Existing NOx Control		Water Injection	Steam Injection

Table 3 – Example 1 Order of Magnitude Cost Summary

Reference Case[1]	Control Technology	Project Cost[2]	Annual O&M Cost[3]
Example 1	SCR System	$16,000,000	$70,000
	DLN / ULN	$2,500,000	$60,000
	Water Injection	$5,000,000	$100,000
Example 2	SCR System	$6,200,000	$300,000

Notes:

1 – Costs based on a retrofit of the sample unit described in Table 2.

2 – Project Costs are overnight total project costs, including all project indirects. All costs are provided in 2021 dollars, reference project cost information used as the basis was adjusted to 2021 dollars using on an escalation factor of 2.5% based on the industry trends over the last ten years (2010 – 2020) excluding the current market conditions.

3 – O&M costs consider loss of power sales due to additional turbine back pressure along with aux power consumption, reagent, and catalyst costs.

As shown in Table 3 above, an SCR system is expected to have the highest project cost of the three evaluated technologies for simple cycle, with the DLN and Water Injection system capital costs being much lower. Cost for the simple cycle SCR factors in a new stack, reactor casing, tempering air system, and a reagent injection system, accounting for large capital items that are not necessary for DLN and water injection. The cost for a NGCC SCR is much smaller, due to only including catalyst, AIG, and an ammonia system; it is assumed that there is already additional space reserved within the HRSG for the catalyst and AIG itself and that the flue gas velocity and temperatures are already appropriate for SCR operation.

Table 4 below summarizes additional considerations when evaluating the capital and operating costs of NO_x reduction technologies that may have a large impact on the overall project.

Table 4 - Capital and Operating Cost Considerations

Control Technology	Capital Cost	Operating and Maintenance Cost
Water / Steam Injection	May require an upgrade to the water treatment system. Cost can increase if a new water treatment system is required.	Requires high quality water for injection and continued inspection and maintenance.
Dry / Ultra Low NO_x	New combustors that must replace existing conventional type. More expensive than conventional combustors.	General maintenance similar to conventional combustors.
Selective Catalytic Reduction	Moderate incremental cost for including in initial NGCC HRSG design. High cost for simple cycle systems to provide a separate reactor.	Reagent supply, catalyst replacement, and general maintenance. Catalyst and reactor pressure drop can decrease turbine output.