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Enhanced turbine monitoring using emissions measurements and data reconciliation

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HIGHLIGHTS

- A diagnostic tool to indicate turbine system problems is proposed.
- NO_x emissions can enhance the data reconciliation process in turbine systems.
- NO_x emissions measurements and data reconciliation can find turbine system problems.

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ABSTRACT

Standard monitoring within a gas-turbine based cogeneration system includes key flow rates, temperatures, pressures and turbine vibration. These standard measurements can be enhanced with continuous emissions monitoring to help pinpoint system problems. A combination of these measurements, a fast NO_x prediction model and data reconciliation constitute an improved monitoring and diagnostic tool that can quantitatively predict the existence of turbine problems (for example, damaged combustor nozzles) even when standard turbine monitoring indicates no problems exist.

1. Introduction

The cogeneration of heat and power is integral to many industrial processing sites. Cogeneration systems represent a large capital investment with costs approaching $1 MM/MW of installed capacity. The gas turbine is the heart of the cogeneration plant. For gas turbines, the early detection of many common problems is difficult, but of critical importance. Unexpected shutdowns of a gas turbine can result in a large increase in the electricity demand charge from the local utility. Such increases typically last one year.

Repair of the combustion chamber in a nominal 20 MW turbine can easily exceed $1/4 MM. On a routine basis (per 4000 h of operation or every six months) turbines are physically inspected to ensure that their bearings and rotors are intact, e.g., no damaged blade tips. Also, turbine vibration is continuously monitored to detect these same problems. A large body of literature is devoted to the importance of performance monitoring and early problem detection. The components of monitoring and detection include data extraction, fault detection, fault location and prognosis [1–4]. Much of the current literature focuses on fault location algorithms which can be broken down into pattern recognition methods such as fuzzy logic [5,6], genetic algorithms [7], Bayesian belief networks [8–10], and neural networks [11–14] and model identification methods such as Kalman filtering [15] and weighted least squares [16–18]. But despite continuous developments in all of these physical and computational techniques, serious gas turbine problems can still quickly develop before corrective actions can take place. For example, fuel nozzles can develop internal cracks that may not immediately affect the gross (vibrational or temperature/pressure) performance of the gas turbine. Such problems are not immediately detectable by standard performance monitoring/diagnostic tools.

In this work we present an improved diagnostic tool to indicate the early onset of problems in a turbine system by utilizing measured NO_x emissions. The quantity of emissions, including NO_x,

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CO, SO_2, VOC and particulates, is regulated at most facilities, so highly accurate NO_x measurements in the exhaust stack are available. As an added benefit, early detection of turbine problems by this method can also help prevent emissions violations. This work significantly contributes to fault simulation methodology by coupling the thermodynamically consistent GRI-Mech 3.0 for natural gas combustion to emissions measurements and engine performance. This deterministic method does generate an easy to implement strategy involving polynomials, because it is just an empirical fit of observed emissions. The current model (using GRI-Mech 3.0) accounts for 53 species and 325 reactions.

All useful diagnostic tools require highly reliable data. Gross error detection and data reconciliation are established techniques to ensure that plant data (chemical and petrochemical, mineral processing, etc.) satisfy material and energy balances [19,20], leading to improved accuracy. These techniques are of increasing importance to the power industry including nuclear power plants [21], coal-fired [22] and combined cycle power plants [23]. Data reconciliation can be used to establish validated cogeneration system operating conditions using the measured flow rates for steam production, natural gas, air, and water injection, along with measured temperatures and pressures. An accurate temperature within the turbine's annular combustion chamber is usually not measured, due to the harsh environment [24], but this temperature is obtainable (observable) from the data reconciliation process. In this work we formulate a chemical reaction model for a natural gas feed in order to relate measured NO_x emissions to the annular combustor temperature. Data reconciliation with the global test method is then used to identify problems within major components of the cogeneration system. At most installations, even if a change in NO_x emissions were detected, this change would not become part of the data reconciliation or used to help pinpoint where problems may exist, because an annular combustor performance model would also be needed.

2. Process description

2.1. LSU's cogeneration system

Louisiana State University installed a 20 MW cogeneration system in 2006 to help meet campus electricity and steam demands. The system utilizes a GE LM-2000 aeroderivative engine operating with natural gas fuel. Water injection is one of the technologies used to control the NO_x emissions [25]. Fig. 1 depicts the cogeneration system, consisting of an air compressor, annular combustor, gas turbine, power turbine and heat recovery steam generator (HRSG). Ambient air (state 0) passes through a cooler to adjust its temperature to a nominal 520 R. Regardless of the ambient temperature, state 1 will always be ~520 R, because this helps maximize turbine performance. Water is the heat exchange fluid in the air cooler, chilled water used on hot days or chilled water produced otherwise. This consistent incoming air temperature at state 1 does influence modeling and observed NO_x. Natural gas, with compressed air and injected water, is burned in the combustor, which delivers hot exhaust gases to the gas generating turbine (expander). We assume (for calculation purposes) that all the work done by the gas generating turbine powers the compressor. The power turbine is connected to an electrical generator. The HRSG includes both economizer and evaporator sections.

Water injection in the combustion chamber moderates the flame zone temperature, both reducing the NO_x and increasing the power output. The water exits with exhaust gas in the stack. The drawbacks of water injection include additional costs for treated water, but, more seriously, water injection can promote abnormal wear of the fuel injectors or the turbine blades.

A Vivicom Continuous Emissions Monitoring System (CEMS) monitored the NO_x emissions at the stack continuously. The CEMS pumps a sample from the stack, converts any NO_2 to NO, then measures the combined NO_x in the range of 0–450 ppmvd (ABB Limas 11UV photometric analyzer). The meter is calibrated daily with a bottled calibration gas (Airgas, Certified Standard). To measure the CO and any unburnt hydrocarbon emissions, the exhaust was sampled into evacuated 500 mL 316 stainless steel bombs. These samples were analyzed using an Agilent 490 Micro GC containing 5A molecular sieve and Porapak U columns. Analysis conditions were 10 min, 80 °C, helium carrier gas. Fuel (natural gas) samples were also analyzed similarly, as NO_x and other emissions vary with fuel composition.

2.2. Standard cogeneration system diagnostic tools

The flow rates, temperatures, pressures and turbine vibration monitored by the distributed control system can help identify any abnormalities in the combustor/gas turbine. A key diagnostic is the exhaust gas temperature spread at the power turbine inlet. As shown in Fig. 2, 11 thermocouples at this location are mounted radially. Current diagnostic strategy is to flag a temperature difference greater than 150 °F between any two thermocouples. For any temperature difference exceeding 200 °F, usual practice is to shut down the turbine.

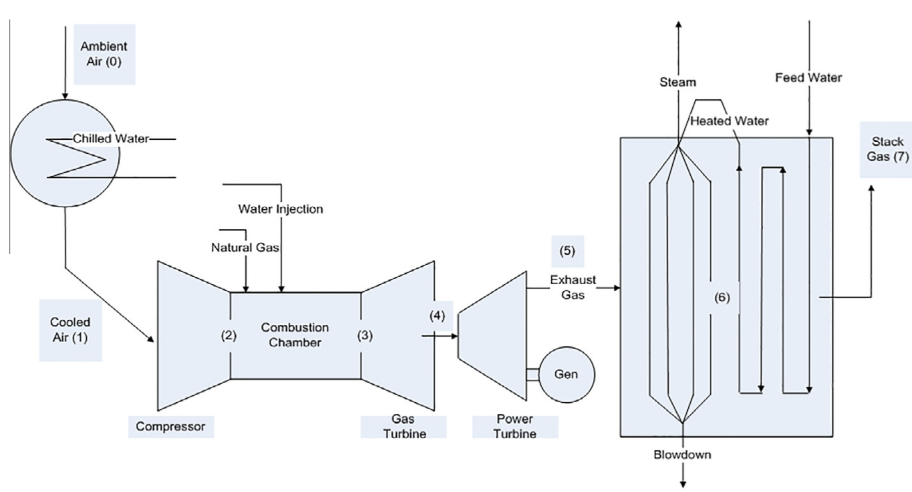

Fig. 1. Gas turbine cogeneration system – air cooler, turbine system and HRSG.