

# NO<sub>x</sub> Emissions from Hydrogen-Methane Fuel Blends

---

**Christopher Douglas**, Research Engineer, Georgia Institute of Technology

**Benjamin Emerson**, Senior Research Engineer - Georgia Institute of Technology

**Timothy Lieuwen**, Executive Director - Strategic Energy Institute, Georgia Institute of Technology

**Tom Martz**, Principal Technical Leader - Electric Power Research Institute

**Robert Steele**, Technical Executive - Electric Power Research Institute

**Bobby Noble**, Gas Turbine Programs Manager - Electric Power Research Institute

January 2022



Georgia Tech  
Strategic Energy  
Institute

Concerns associated with climate change are leading to a variety of new proposals to reduce the carbon dioxide (CO<sub>2</sub>) emitted by global energy and transport systems. In addition to producing CO<sub>2</sub>, many energy systems also release a variety of pollutants to the atmosphere, raising environmental and respiratory health concerns. As such, emissions associated with the combustion of fuels are regulated by a variety of national and local authorities. For example, in the US, subpart KKKK of the EPA code lays out federal emissions limits for nitrogen oxides (NO<sub>x</sub>) and sulfur dioxide (SO<sub>2</sub>). The primary source of NO<sub>x</sub> in most gas-fired systems comes from the ambient air itself, as its dominant constituents (nitrogen, N<sub>2</sub>, and oxygen, O<sub>2</sub>) react together under high temperature conditions. A variety of proposals are in place to utilize hydrogen (H<sub>2</sub>) as a green energy carrier which can be transported in pipelines and burned by a variety of stationary and mobile sources, such as power plants, heaters, and trucks. As a carbon-free fuel, hydrogen has the desirable property that its combustion releases no CO<sub>2</sub>. However, H<sub>2</sub> combustion does generate NO<sub>x</sub> since, as noted above, NO<sub>x</sub> is formed when air is heated to high temperatures.

From a NO<sub>x</sub> emissions perspective, the combustion of fuel blends containing H<sub>2</sub> raises two key issues. First, changes in fuel composition affect NO<sub>x</sub> production pathways and, therefore, can directly alter the amount of NO<sub>x</sub> generated by a system operating at a given power output. This issue is not addressed here, but is discussed in a companion white paper. Second, regardless of the actual NO<sub>x</sub> emissions per unit of power, changes in fuel composition can indirectly influence the reported NO<sub>x</sub> emissions due to details of the accounting and bookkeeping methods used to measure and report NO<sub>x</sub> emissions across a variety of fuel blends and devices. This whitepaper focuses on the latter issue and, in particular, shows that many studies could be interpreting their NO<sub>x</sub> emissions incorrectly by as much as 40% against high-hydrogen systems.

The environmental and air quality community has well-developed approaches to account for these variations which are factored into allowed emissions associated with air quality permits. Typically, these permitted levels can ultimately be traced back to net mass production of regulated pollutants. However, it is volumetric stack concentrations of pollutants, and not their actual mass production rates, which are actually measured using the continuous NO<sub>x</sub> analyzers at the plant. As such, methods are needed to convert volumetric measurements (ppmv) to a mass basis (lb/MMBtu or lb/hr). For example, codes for gas turbine emissions often define allowable fractions of exhausted NO<sub>x</sub> based on standardized sample preparation processes. In this standard process, the combustion products are sampled, the water is removed, and the dry sample is mathematically corrected simulate air dilution to 15% O<sub>2</sub> (for gas turbines) before measuring the NO<sub>x</sub> levels. This correction approach is performed in order to evenly evaluate systems with varying levels of excess air. In the United States, typical stack exit permits are on the order of 3-30 ppmv @ 15% O<sub>2</sub>. However, the constant of proportionality between mass production of pollutants and this measured ppmv value is in fact fuel dependent. Again, this point is well known in the environmental community, and corrected via an “F-factor.” However, a key motivator for this whitepaper is that the combustion community, which is currently evaluating low NO<sub>x</sub> combustion technologies with results that are being used by a wide variety of stakeholders in evaluating the benefits of a hydrogen economy, is often not applying this correction and improperly comparing measured NO<sub>x</sub> ppmv emissions between one fuel and another. For example, many papers in the literature are directly comparing NO<sub>x</sub> emissions from methane/hydrogen blends, based on these NO<sub>x</sub> ppmv concentration values. While this correction is negligible for many fuels (e.g., when comparing between natural gas and diesel fuel), it is very substantial for hydrogen.

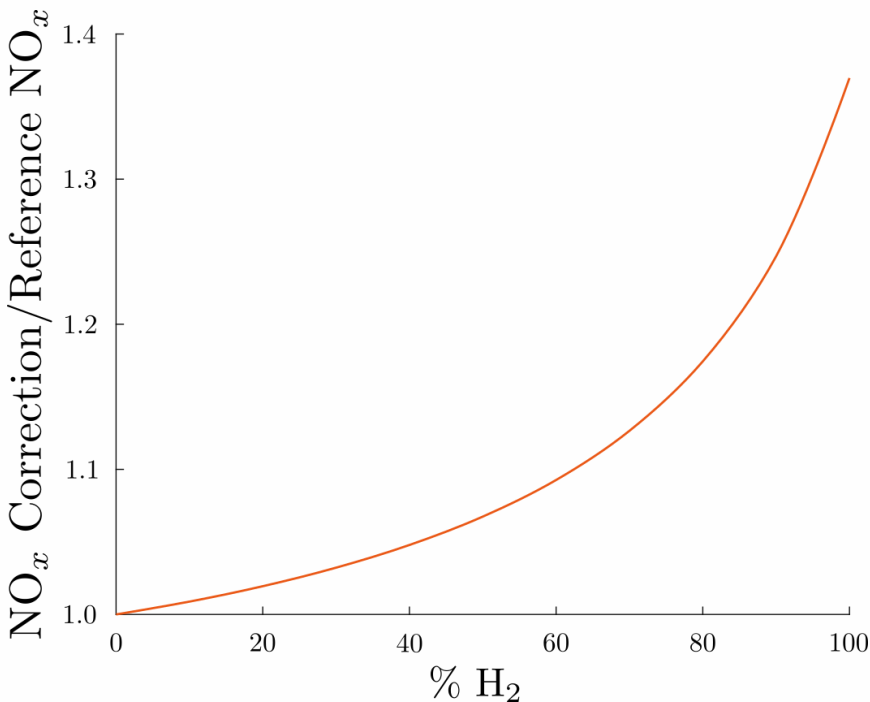
However, as will be discussed in this whitepaper, at conditions with equal power output, hydrogen/methane fuel blends yield combustion products with higher proportions of H<sub>2</sub>O and O<sub>2</sub> than pure methane. Hence, even when the mass production rate of NO<sub>x</sub> emissions are identical, higher hydrogen systems will have higher composition-based value when reported in ppmv @ 15% O<sub>2</sub>. The next section presents a simple way to correct for this.

## NO<sub>x</sub> Corrections for H<sub>2</sub>-containing Fuel Blends

To demonstrate the effect of fuel composition on NO<sub>x</sub> emissions calculated using the dry concentration corrected to 15% O<sub>2</sub>, this section presents correction curves, assuming that the different blends are operated at the same flame temperature. Equilibrium chemistry calculations are performed for fuel blends ranging in composition from pure methane to pure hydrogen at constant adiabatic flame temperature. Assuming equal molar NO<sub>x</sub> production across these conditions, the dry NO<sub>x</sub> @ 15% O<sub>2</sub>, relative to that for pure natural gas are shown Figure 1. When using ppmv-based values, the emissions should be divided by the value on the vertical axis for a given hydrogen fraction. While the results in this plot are specific to the pressure and the reactant and flame temperatures noted in the caption, the correction curve varies only weakly for other conditions.

The key point is to show how a volume-based (ppmv) measurement approach can indicate higher NO<sub>x</sub> emissions from H<sub>2</sub>-blended systems for the exact same mass of NO<sub>x</sub> as a methane-fired plant. For example, this correction is about 7% for a 50%/50% H<sub>2</sub>/CH<sub>4</sub> blend, 17% for an 80%/20% blend, and 37% at 100% H<sub>2</sub>.

Although not shown, similar corrections for other common fuels are generally negligible. For example, consider the case of *n*-dodecane (an approximate simulation of diesel fuel), where the corresponding ratio between 100% methane and dodecane fuel for the two conditions shown in the appendix are 0.996 and 0.979, i.e., only 2%. This appears to be the reason that this correction is not widely appreciated in the combustion test community.



*Figure 1: Dry NO<sub>x</sub> emissions (in ppmv @ 15% O<sub>2</sub>) for a constant temperature system operated at various hydrogen/methane ratios relative to the dry NO<sub>x</sub> emissions from pure methane. When using ppmv-based values, the emissions should be divided by the value on the vertical axis for a given H<sub>2</sub>-fraction. Results calculated for 300 K reactants at 1 bar with adiabatic flame temperature of 2000 K.*

## Appendix: Tabulated Corrections

### 1 bar, 300 K reactants, $T_{ad} = 2000$ K

Fuel % H <sub>2</sub>	Fuel % CH <sub>4</sub>	Prod. %CO <sub>2</sub>	Prod. %H <sub>2</sub> O	Prod. %O <sub>2</sub>	NO <sub>x</sub> corr.	Ratio
0	100	7.69	15.38	3.70	0.4264	1.000
20	80	7.15	16.07	3.82	0.4347	1.019
40	60	6.39	17.03	4.00	0.4468	1.048
60	40	5.27	18.45	4.25	0.4659	1.092
80	20	3.46	20.74	4.66	0.5008	1.174
100	0	0.00	25.13	5.45	0.5840	1.370

### 20 bar, 700 K reactants, $T_{ad} = 2000$ K

Fuel % H <sub>2</sub>	Fuel % CH <sub>4</sub>	Prod. %CO <sub>2</sub>	Prod. %H <sub>2</sub> O	Prod. %O <sub>2</sub>	NO <sub>x</sub> corr.	Ratio
0	100	6.04	12.05	7.39	0.5414	1.000
50	50	4.61	13.78	7.76	0.5800	1.071
100	0	0.00	19.37	8.96	0.7528	1.390

## References

1. Emerson, B., Lieuwen, T., Espinoza, N., Noble, B., "Hydrogen Utilization in the Electricity Sector: Opportunities, Issues, and Challenges." (<https://doi.org/10.35090/gatech/65364>)
2. Shigehara, Roger T., and Howard F. Schiff. "Determining F-factors from Gas Chromatographic Analyses," *Source Evaluation Society Newsletter* 22.2 (1998): 7-l.
3. Mehmet Salih Cellek, Ali Pınarbası, "Investigations on Performance and Emission Characteristics of an Industrial Low Swirl Burner While Burning Natural Gas, Methane, Hydrogen-enriched Natural Gas and Hydrogen as Fuels," *International Journal of Hydrogen Energy*, Volume 43, Issue 2, 2018, Pages 1194-1207, ISSN 0360-3199. <https://doi.org/10.1016/j.ijhydene.2017.05.107>
4. Therkelsen, P., Werts, T., McDonell, V., and Samuelsen, S. (February 19, 2009). "Analysis of NO<sub>x</sub> Formation in a Hydrogen-fueled Gas Turbine Engine." ASME. *J. Eng. Gas Turbines Power*. May 2009; 131(3): 031507. <https://doi.org/10.1115/1.3028232>
5. Todd, D., & Battista, R. (2001). Demonstrated Applicability of Hydrogen Fuel for Gas Turbines.
6. Stuttaford, P, Rizkalla, H, Chen, Y, Copley, B, & Faucett, T. "Extended Turndown, Fuel Flexible Gas Turbine Combustion System," ASME. <https://doi.org/10.1115/GT2010-22585>
7. Lacy, B, Ziminsky, W, Lipinski, J, Varatharajan, B, Yilmaz, E, & Brumberg, J. "Low Emissions Combustion System Development for the GE Energy High Hydrogen Turbine Program," ASME. <https://doi.org/10.1115/GT2008-50823>
8. Bullard, T, Steinbrenner, A, Stuttaford, P, Jansen, D, & de Bruijne, T. "Improvement of Premixed Gas Turbine Combustion System Fuel Flexibility with Increased Hydrogen Consumption in a Renewable Market Place," ASME. <https://doi.org/10.1115/GT2018-75553>