
Hydrogen Blending and Cofiring Demonstration Project at Halton Hills

Atura Power

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1. Executive Summary

The Halton Hills Hydrogen Blending Project, led by Atura Power (Atura) and supported by the Independent Electricity System Operator (IESO) through the Hydrogen Innovation Fund 2023, is pioneering a utility-scale demonstration aimed at reducing the carbon intensity of electricity generation in Ontario.

This initiative focuses on retrofitting the Halton Hills Generating Station (HHGS) to enable blending of hydrogen with natural gas in its Siemens Energy SGT6-5000F combined cycle gas turbines. The project demonstrates the technical and operational feasibility of hydrogen blending at up to 15% by volume, with the goal of maintaining full participation in IESO-administered electricity markets while reducing greenhouse gas (GHG) emissions.

1.1 Project Scope and Milestones

The project was structured around three key milestones:

1. **Engineering & Procurement** – Design, fabrication, and delivery of hydrogen blending skids and associated equipment.
2. **Construction, Commissioning & Operation** – Installation and integration of blending systems into HHGS, followed by commissioning and operational readiness.
3. **Testing for Wholesale Grid Services** – Performance testing at 5%, 10%, and 15% hydrogen blends to assess impacts on turbine operation, market responsiveness, and emissions.

1.2 Key Outcomes

- **GHG Emissions Reduction:** Calculated CO₂ reductions of up to **5%** at 15 vol% blend, with potential for further reductions at higher blend ratios.
- **Grid Reliability:** The CTG delivered stable operation, full ramping capability, and OR performance while co-firing hydrogen, demonstrating no adverse impact to real-time market participation.
- **Successful Technology Integration:** HHGS became the **first utility-scale Canadian plant** to integrate hydrogen blending infrastructure and operate reliably across the full 0–15% range
- **Effective Emissions Management:** NO_x and CO remained within expected operating ranges
- **Foundational Insights:** The trials validated technical feasibility and highlighted economic, regulatory, and infrastructure requirements needed for commercial adoption.

1.3 Innovation and Impact

This project is the first commercial-scale hydrogen blending initiative for electricity generation in Canada, setting a precedent for future deployments across the country's gas-fired power plants. It provides critical data to inform policy, regulatory frameworks, and future investment decisions in hydrogen infrastructure and clean energy technologies.

While the original proposal referenced Atura's Niagara Hydrogen Centre (NHC) as a potential hydrogen source, NHC's hydrogen was not available at the time of testing and hydrogen was instead sourced through alternative means.

The project supports Ontario's climate goals and contributes to the IESO's published Pathways to Decarbonization [R1] by enabling dispatchable, low-carbon generation during peak demand periods.

2. Abbreviations

Acronym Abbreviation	/Description
AHJ	Authority Having Jurisdiction
CEMS	Continuous Emission Monitoring System
CHIC	Canadian Hydrogen Installation Code
CO	Carbon Monoxide
CO ₂	Carbon Dioxide
CRN	Canadian Registration Number
CTG	Combustion Turbine Generator
DCS	Distributed Control System
ESA	Electrical Safety Authority
GHG	Green House Gas
HAZOP	Hazard and Operability Study
HBS	Hydrogen Blending Skid
HHGS	Halton Hills Generating Station
HHV	Higher Heating Value
HIF	Hydrogen Innovation Fund
H ₂	Hydrogen
IESO	Independent Electricity System Operator
LHV	Lower Heating Value
MLP	Minimum Load Point
NG	Natural Gas
NO _x	Oxides of Nitrogen
NHC	Niagara Hydrogen Centre
OR	Operating Reserve
PHA	Process Hazard Analysis
PRS	Pressure Reduction Skid
S-E	Siemens-Energy

Sm ³	Cubic meters of a gas reported at standard conditions (101.225 kPaa and 15°C)
TSSA	Technical Safety and Standards Authority
vol%	Percent by Volume

3. Introduction

Atura Power is the owner and operator of the Halton Hills Generating Station (HHGS), a natural gas-fired power plant located in Milton, Ontario. HHGS is a 710MW Combined Cycle Power plant with a 2x1 configuration. The plant is equipped with two (2) Siemens Energy (S-E) combustion turbine generators (CTG), two (2) Alstom Heat Recovery Steam Generators (HRSGs) and an Alstom Steam Turbine. HHGS has been providing safe, reliable and dispatchable power to Ontario's grid since 2010.

As part of its support towards reducing carbon emissions and supporting broad industry decarbonization, Atura implemented a Hydrogen Blending Project (the 'Project'). The Project is a first-of-its-kind, utility-scale demonstration of hydrogen blending for electricity generation in Canada led by Atura Power and supported by the Independent Electricity System Operator (IESO) through the Hydrogen Innovation Fund (HIF). The project aimed to demonstrate the technical, operational, and market feasibility of hydrogen blending for cofiring in the CTGs at up to 15% by volume, with infrastructure designed to scale to 30%, pending future CTG modifications. With 15 vol% hydrogen content, it is expected that the carbon dioxide (CO₂) will be reduced in the order of approximately 5%, and at 30 vol% hydrogen content the expected CO₂ reduction is approximately 12%.

3.1 Project Overview

Hydrogen was delivered to site via mobile gaseous tube trailers where its pressure was reduced using mobile pressure reduction skids (PRS) and then injected into the CTG fuel delivery system using purpose-built hydrogen blending skids (HBS) that ensured the homogeneous mixing of hydrogen and natural gas prior to combustion. Once mixed, the fuel gas blend was consumed in the CTG operating at power levels between the Minimum Load Point (MLP) and Baseload (full power).

The project included piping and equipment associated with both temporary and permanent installations at the facility. The temporary installation comprised of bays for 4 mobile tube trailers (that also served as onsite hydrogen storage), two mobile PRSs to reduce the pressure from tube trailers (180 barg when fully filled) to supply the CTGs (approximately 41 barg), and a piping header that connected the PRS to the permanent hydrogen piping at HHGS. The permanent plant equipment included a stainless-steel piping system that transported hydrogen from each PRS unit and distributed hydrogen gas to two HBSs (one HBS for each CTG). This piping network also consisted of an over pressure protection system (i.e., pressure safety devices, vent header and vent stacks) as well as ancillary systems (i.e., nitrogen, instrument air, etc.) to facilitate proper operation.

During operation, the HBS controls the hydrogen flow to provide the hydrogen blend ratio selected by an operator (i.e., 0-15 vol% for these trials). Once a hydrogen blend rate was selected, the controlled flow of hydrogen was piped to an injection point in the fuel gas system and the homogenous fuel gas mixture of hydrogen and natural gas was supplied to the CTG.

For the blending system commissioning and trials, gaseous hydrogen was delivered to the HHGS site in pressurized tube trailers from a commercially available source. As the Ontario hydrogen market develops, hydrogen may be sourced from production via electrolysis or other new technologies, from low-carbon intensity power sources such as the Ontario grid, hydro power, wind, and/or solar.

The following image, Figure 3-1, depicts the equipment layout associated with the temporary and permanent equipment installation of the hydrogen blending infrastructure at HHGS:

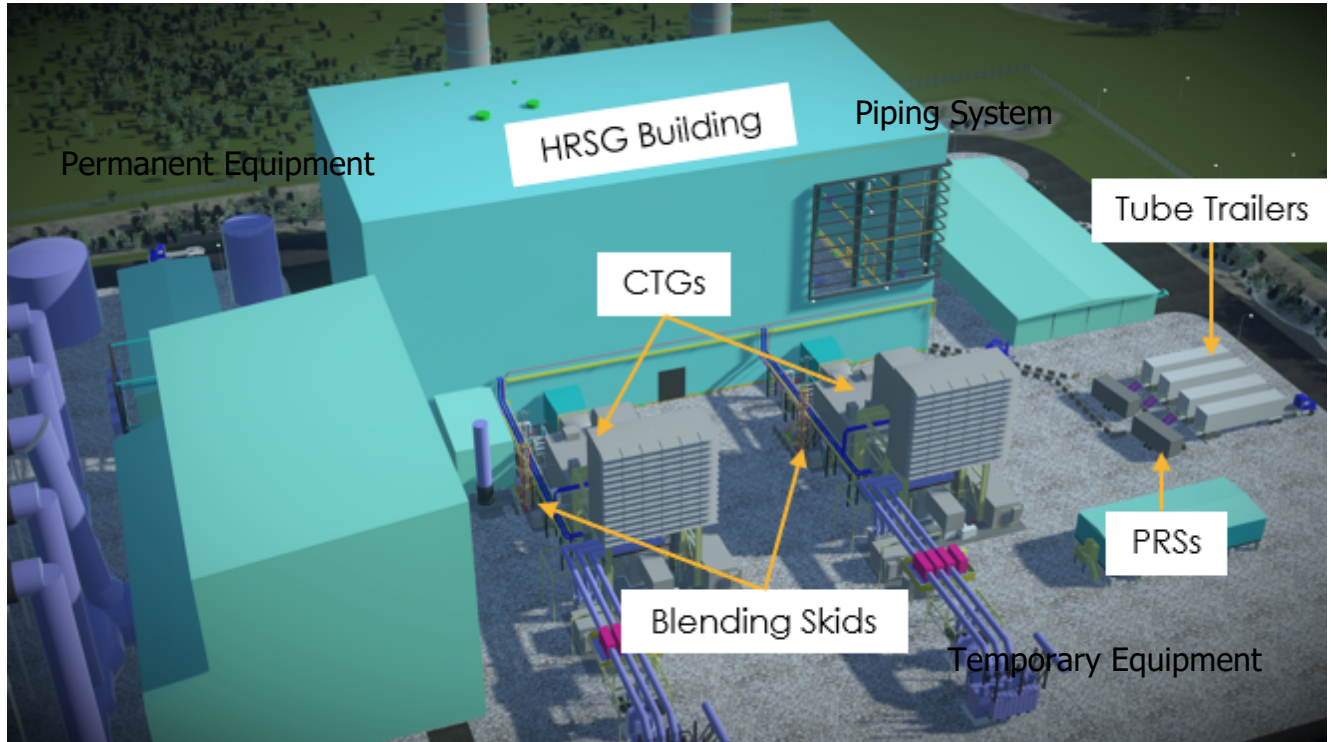


Figure 3-1: Hydrogen Blending Infrastructure at HHGS

Prior to formal IESO testing, the installed hydrogen blending system included cold commissioning of both HBS units to validate the functionality of all valves and sensors of the control system. Once validated, each HBS underwent hot commissioning cofiring testing that consisted of three separate test days for each CTG. The test duration was planned between 3 and 4 hours each day to align with the amounts of hydrogen available in the four mobile tube trailers (1,200 kg to 1,500 kg total hydrogen per day). Commissioning concluded upon demonstration of a stable operating combustion system that can cofire using up to 15 vol% hydrogen.

Once commissioning was completed, the hydrogen cofiring system was handed over to Atura's operational staff to perform the testing protocol as approved by the IESO. The hydrogen blending trials were performed over 2 days.

Upon the completion of the formal hydrogen blending trials, the mobile hydrogen tube trailers, the PRS units and piping associated with the temporary installation was decommissioned and removed from the HHGS site. The permanent site equipment was de-energized, physically isolated from the operational plant and preserved to permit future operations.

3.2 Scope

The scope of this project was broad and encompassed several engineering and professional disciplines to design, procure, install, commission and operate the hydrogen blending system, and are summarized below:

- **Engineering and procurement** activities related to blending infrastructure (HBS, interconnecting piping, vent systems, pressure reduction skids and tube trailers), which included the development of P&IDs, electrical area classification, general arrangement and detailed drawings. This phase also included permitting and equipment registration with the authority having jurisdiction (AHJ) (i.e., the ESA and TSSA). The blending skids were issued a CRN with TSSA BPV (Boiler and Pressure Vessels), and TSSA FS (Fuel Safety) was engaged in the design registration of the High Pressure Piping (HPP) sections of the blended fuel gas as well as the hydrogen piping.
- **Installation, safety checks and commissioning** of the HBSs, the PRSs, ancillary systems (e.g., nitrogen, instrument air), interconnecting piping, tie-ins and the control system. Cold and hot commissioning, integration with existing plant controls and operational testing was performed. These activities also included the verifications of overpressure protection systems, as well as performing pressure tests (mechanical integrity) and leak detection, system purging and system charging with hydrogen.
- **Performance testing** with the IESO-approved testing protocol to show the ability of a CTG to operate under different operating conditions 5%, 10%, and 15% hydrogen blends rates.
- **Evaluation of combustion performance** such as emissions savings, ramping capabilities, and market responsiveness
- **Decommissioning of temporary hydrogen supply infrastructure** —including mobile tube trailers, pressure reduction skids (PRS), and associated piping—were safely shut down and removed from the Halton Hills Generating Station (HHGS). Permanent hydrogen blending equipment was isolated and preserved for potential future use.

3.3 Purpose

The purpose of this document is to summarize the results of the formal IESO trials at HHGS using blended hydrogen and natural gas as a CTG fuel.

4. Approach/Methodology and Assumptions

4.1 Testing Overview

This section provides an overview of the methodology used during the commissioning and testing at HHGS. The methodology has been summarized from the IESO-approved protocol [R2] and supplemented with the operator inputs.

Test cases are summarized in Table 4-1 and align with the approved protocol. An overview of each test type is provided in subsequent sections along with the nominal hydrogen blend profiles.

Table 4-1: Test Cases, Type and Blending Percentage.

Test Case	Test Name	Hydrogen Blend Percentage (vol%)
Test 1	Ramp CTG from MLP to Baseload	0, 5, 10, 15
Test 2	Ramp CTG from Baseload to MLP	0, 5, 10, 15
Test 3	Operating Reserve Activation	5, 10, 15

Test 1 and Test 2 were completed to demonstrate:

- The ability of the CTG to hold steady state output at MLP or baseload, while changing blending levels within expected design values.
- The ability of the CTG to ramp (up or down) according to a prescribed ramp rate while changing blend levels.
- Changes in heat rate and emission output levels.
- The fuel control system's ability to adjust blending ratios, including recovering from a hydrogen trip.

Test 3 was completed to demonstrate:

- The ability of the CTG to hold steady state outputs at both MLP and (MLP+25MW) at fixed blending levels (5 vol%, 10 vol%, 15 vol%).
- The ability of the CTG to provide 10 minutes OR (i.e., reach OR target within 10 minutes) at each blending level.
- Changes in heat rate and emission output levels.

Each test was performed once, and testing was conducted using one (1) CTG (i.e., Unit 1 CTG). Data was collected during the formal IESO blending trials from three sources: the CTG, the HBS, and the continuous emission monitoring system (CEMS) analyzer within the vent stack. CTG data provided the power generated and the natural gas flow rate. The data collected by the HBS provided the actual hydrogen flow rate and the actual (calculated) volume percent of the blend that was mixed with the natural gas. Finally, the CEMS captured the NO_x and CO emissions at the CTG stack outlet. All data sources were time-stamped allowing for the synthesis of data into a complete dataset.

4.2 Pre-test Commissioning Activities

System commissioning was conducted by personnel from S-E over a period of 5 days prior to data collection. S-E was responsible for the commissioning as they are the OEM of CTGs and designed, manufactured and installed the HBSs.

Commissioning was initiated with steady-state hydrogen co-firing operation (i.e., fixed CTG load), with varying hydrogen content across the entire blending range (i.e., 0 vol% to 15 vol%). On subsequent commissioning days, the CTG load was varied while hydrogen was maintained constant followed by operation where the CTG load and hydrogen blend percentage were varied simultaneously.

The testing validated the function of the blending system over the entire operating range of load from MLP to Baseload and hydrogen co-firing from 5 vol% to 15 vol%. In addition to these load tests, operation modes that addressed how the control system reacts to a low hydrogen supply pressure and hydrogen depletion tests ("trip tests") were conducted to ensure that the control system could respond and transition to 100 vol% natural gas without impacting CTG electrical output.

As part of the commissioning phase, HBS control loops were tuned, CTG combustion parameters were optimized for hydrogen co-firing, and blending gas samples were gathered and taken to an independent testing facility to confirm composition.

The commissioning was conducted with the IESO and the Atura Commercial and Operations teams. Careful coordination was required to ensure that the IESO was aware of varying CTG loads (i.e., HHGS load changes during the various ramps, system derates, etc.).

The units were commissioned with the intent that once completed, the HBS and modifications to the HHGS control system were considered permanent and that the system was ready for commercial operation. As such, when hydrogen is available at HHGS in the future, an operator can specify a blend rate from 0-15 vol% and the system will operate accordingly.

Test plans and associated data collected from Unit 1 CTG and Unit 2 CTG commissioning are provided in Appendix 1.

4.3 Ramp CTG from MLP to Baseload Procedure (Test 1)

Test 1 consisted of 3 parts. First, the CTG load was held constant at the MLP while the hydrogen concentration was varied with time between 0 vol% and 15 vol%. This part aimed to observe CTG stability and combustion performance during intermittent hydrogen supply and blend fluctuations. Second, the CTG load was ramped from MLP to Baseload conditions while hydrogen concentration was varied with time. This part aimed to assess CTG performance while increasing the power demand with changes in hydrogen concentration. Finally, a depletion condition was simulated at the end of the test by closing the hydrogen supply valve at the final blend setpoint (15 vol%). The CTG and hydrogen blending setpoints for Test 1 are presented in Figure 4-1.

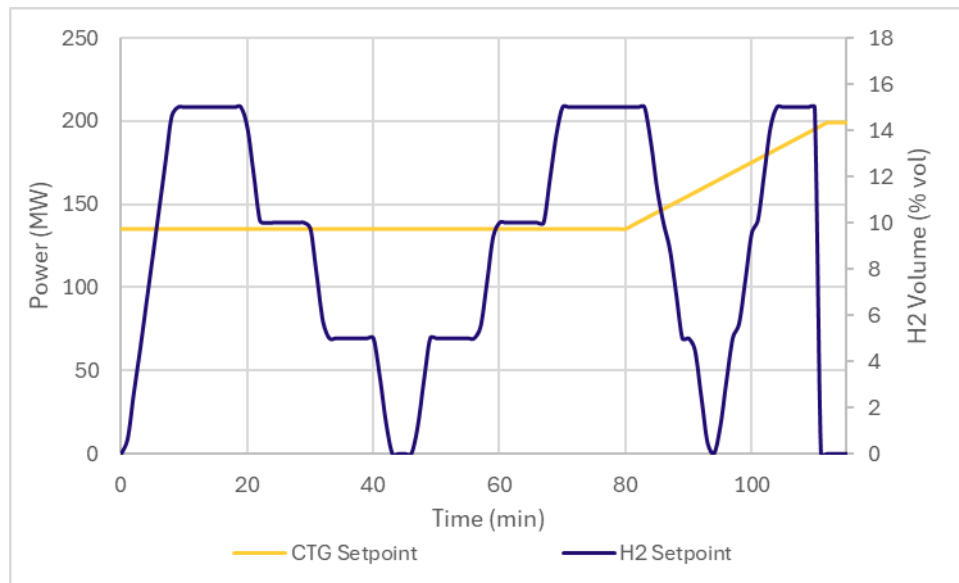


Figure 4-1: Test 1 Profile, CTG Load Setpoint and Hydrogen vol% Target.

Detailed operator setpoints for Test 1 are provided in Appendix 1.

4.4 Ramp CTG from Baseload to MLP Procedure (Test 2)

Test 2 consisted of 2 parts. First, the CTG load was held constant at the Baseload while the hydrogen concentration was varied with time between 0 vol% and 15 vol%. This part aimed to observe CTG stability and combustion performance during intermittent hydrogen supply and blend fluctuations. Second, the CTG load was ramped at both a “slow-ramp rate” followed by a “fast-ramp rate” (indicated by the yellow diamond in the figure) from Baseload to MLP conditions while hydrogen concentration was varied with time. This part aimed to assess CTG performance while decreasing the power demand while the hydrogen concentration was quickly ramped to 15 vol% and then stepped down to 0 vol% and back to 5 vol% before simulating a depletion condition (indicated by purple diamond in the figure). The test was concluded by maintaining hydrogen at 15% until hydrogen was depleted from the tube trailers. The CTG and hydrogen blending setpoints for Test 2 are presented in Figure 4-2.

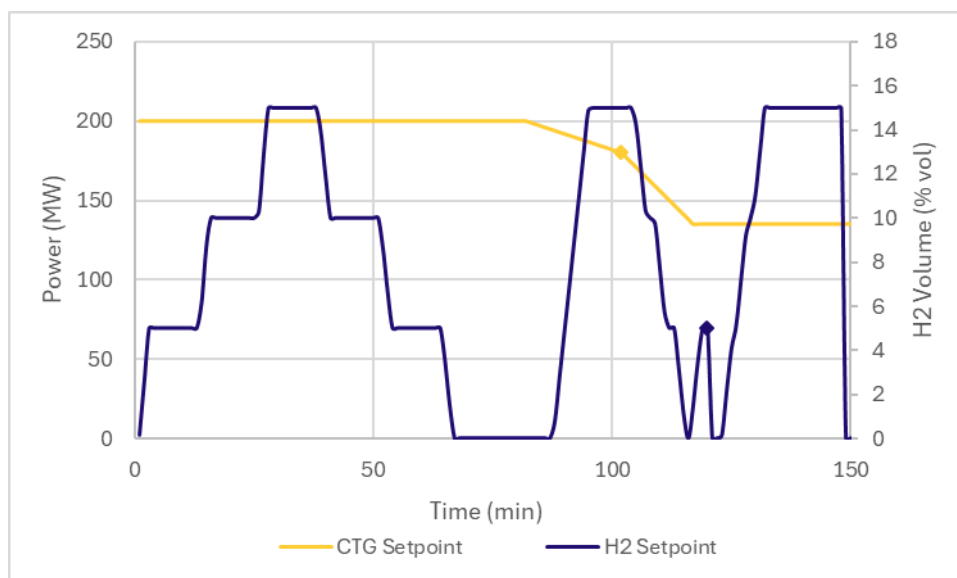


Figure 4-2: Test 2 Profile, CTG Load Setpoint and Hydrogen vol% Target.

Test 2 was supposed to be conducted in a single session (i.e., continuously over one (1) day), however due to the availability of onsite hydrogen, the test was completed partially across two days. The division is noted in the results section for Test 2.

Detailed operator setpoints for Test 2 are provided in Appendix 1.

4.5 Operating Reserve Activation Procedure (Test 3)

Test 3 consisted of 3 parts. During each part of the test, the hydrogen concentration increased from 0 vol% to the setpoint while simultaneously ramping the CTG from the MLP to Baseload conditions. Hydrogen depletion condition was simulated by closing the supply valve at each blend ratio before performing the next part. The 3 parts were at 5 vol%, 10 vol% and 15 vol% hydrogen blend ratios. The CTG and hydrogen blending setpoints for Test 2 are presented in Figure 4-3.

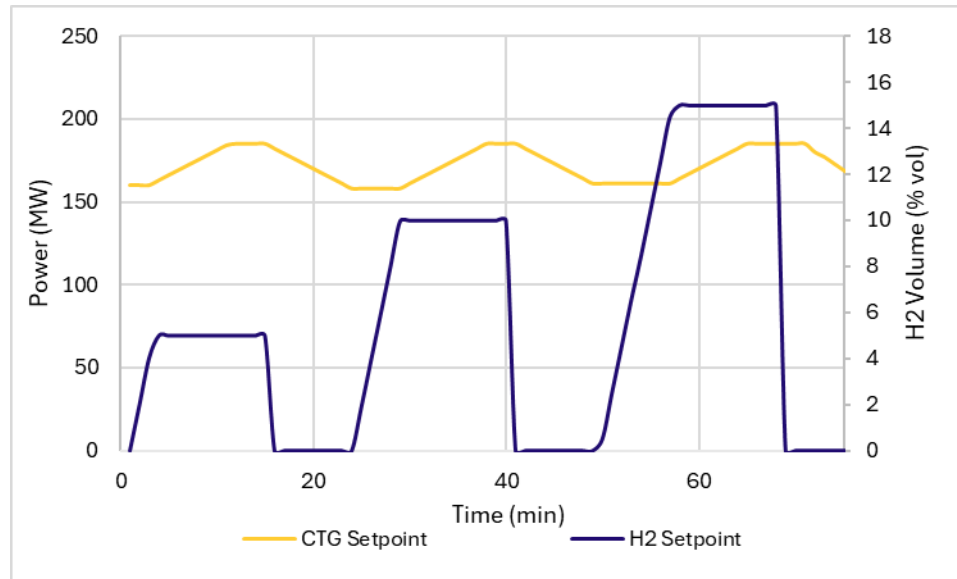


Figure 4-3: Test 3 Profile, CTG Load Setpoint and Hydrogen vol% Target.

Detailed operator setpoints for Test 3 are provided in Appendix 1.

4.6 CO₂ Emissions Calculations

Atura is required to provide greenhouse gas (GHG) emissions data to the Province of Ontario on a yearly basis. To facilitate this, the natural gas fuel consumption (in Sm³) and subsequent carbon content of the natural gas (in metric tons) that were consumed is used to calculate CO₂ emissions (in metric tons) on a month-to-month basis. Informed by Atura's annual emissions report, an emissions factor of 2.73 kg CO₂ / kg NG was calculated by taking the average of the monthly reported CO₂ emissions and dividing it by the average monthly NG consumed. All absolute emissions calculated and reported below used this average emissions factor.

When hydrogen was co-fired with natural gas in the CTG, the CO₂ emissions produced is based on only the natural gas consumed. This value was calculated by taking the natural gas flowrate (on a mass basis) and multiplying it with the emission factor described above (2.73 kg CO₂ / kg NG).

To determine the CO₂ emission reduction by using a blended fuel, the hydrogen portion of the blended fuel (on a mass basis) was converted to an equivalent natural gas quantity (on a mass basis) by using the energy equivalency ratio of H₂ and NG. This energy equivalency conversion from hydrogen to natural gas was performed by using the lower heating values (LHV) of each constituent as follows:

$$NG_{equivalent} \left[\frac{\text{kg}}{\text{hr}} \right] = H_2 \left[\frac{\text{kg}}{\text{hr}} \right] \times \frac{120\text{MJ}}{\text{kg } H_2} \times \frac{\text{kg NG}}{47.8\text{MJ}} \quad Eq (1)$$

Once the equivalent natural gas flowrate was determined for a given blend, it was converted to CO₂ emissions using the emission factor above (2.73 kg CO₂ / kg NG); this value represents the CO₂ emission savings while hydrogen was blended into the CTG fuel.

The sum of the consumed NG and equivalent NG represents the baseline NG consumptions and the associated CO₂ emissions. Emissions data was calculated for each timestep and as a percentage of CO₂ emissions savings relative to the baseline CO₂ emissions.

4.7 Assumptions and Exclusions

- These trials were to be conducted at ambient temperatures greater than 10°C in line with TSSA regulatory approvals. Refer to Lessons Learned for additional details.
- Based on the HBS control valve tuning process and confirmation from gas testing reports during the commissioning phase, the recorded hydrogen blend is assumed to be the actual hydrogen blend due to the unavailability of the continuous gas blend monitoring system during the trials (refer to Lessons Learned for further details).
- Duct burner firing was deactivated for the turbine undergoing testing.

4.8 Operational Deviation

This section describes deviations from the design basis of the equipment or process that was encountered during the testing and its impact on the results.

4.8.1 Continuous Gas Blend Monitoring

Each HBS is equipped with a Coriolis mass flow meter that is used to accurately measure hydrogen as it is dosed into the natural gas system. In addition to direct hydrogen flow measurement, S-E intended

on installing equipment within the fuel gas line to measure the Wobbe Index of the blended gas. The Wobbe Index is a property of a fuel gas that indicates its energy per volume of the gas mixture and can be used for the direct control of combustion gas flow and energy release. S-E also planned on installing an additional inline device that measures the thermal conductivity via gas analyzer to determine the hydrogen content of the blended gas.

At the time of construction, the Wobbe meter and thermal conductivity analyzer could not be installed as the required certification for pressure retaining equipment for these devices was found to be non-compliant with Ontario regulations (i.e., these devices did not have valid Canadian Registration numbers [CRN]). As such these devices could not be used during the co-firing tests. Instead of using these devices, it was decided to draw several samples of the blended gas at 5 vol%, 10 vol% and 15 vol% and use a gas analysis performed by a 3rd party testing laboratory to determine the hydrogen content of the gas to validate the hydrogen flow metering and mixing accuracy of the blending system.

Based on the results of the gas sample analysis, it was found that the blend ratios are within specification and that the gas blend is homogeneous (well mixed and not stratified). Therefore, it can be concluded that this deviation (i.e., operation without Wobbe meter) did not have an impact on the test results.

5. Results and Analysis

This section provides a summary of results and analysis of collected data from the three formal hydrogen blending trials. At a high level, the focus is mainly on CTG power generation, CO₂, NO_x and CO emissions, and CTG heat generation at the selected hydrogen blending percentages.

CTG and HBS tuning were completed during commissioning and are not included in this section due to misalignment with the intended hydrogen and CTG power setpoint profiles as included in the approved testing protocol. Note that all relevant commentary associated with commissioning is provided in the Appendix.

The order of tests is presented in Table 5-1. The testing occurred over the course of two days with Test 3 conducted first due to the low complexity of setpoints and the short test duration. Following the completion of Test 3, Test 1 was performed on Day 1 and ran to completion. Test 2, which also started on Day 1, was completed on Day 2 to match hydrogen availability on site.

Table 5-1: Order of Performed Tests.

Day	Test Performed	Time Range [Duration (min)]
1	Test 3	09:00-10:15 [75]
	Test 1	10:25-12:20 [115]
	Test 2 – partial	12:25-13:35 [70]
2	Test 2 – partial	09:00-10:10 [70]
Day 1: 19 July 2025		
Day 2: 22 July 2025		

5.1 Power Generation and Hydrogen Concentration

CTG power generation (MW) and hydrogen blending (vol%) measurements with respect to time for each test are provided in Figure 5-1 to Figure 5-3. All tests showed stable CTG operation at MLP and Baseload conditions. Minor variability in CTG power was observed during steady state operation and is consistent with normal operation. CTG Power Setpoints were recorded by the operator, as presented in Appendix 1. The hydrogen blending measurements throughout the testing indicated that equipment was functioning as expected and followed the test plan profile.

When operating in hydrogen co-firing mode, the CTG power needed to be reduced (de-rated) with an increasing hydrogen blend ratio to stabilize combustion and to avoid overheating physical components. This was programmed into the CTG control logic during commissioning prior to the trials. The CTG power de-rate is more prominent at Baseload power than MLP as the de-rating is a

function of turbine outlet temperature. The turbine operated as expected and was able to attain the setpoint value typically within 3 minutes of a change in hydrogen concentration (also observed during commissioning, refer to Appendix 2). CTG de-rating during hydrogen co-firing is further discussed in Section 6.1.

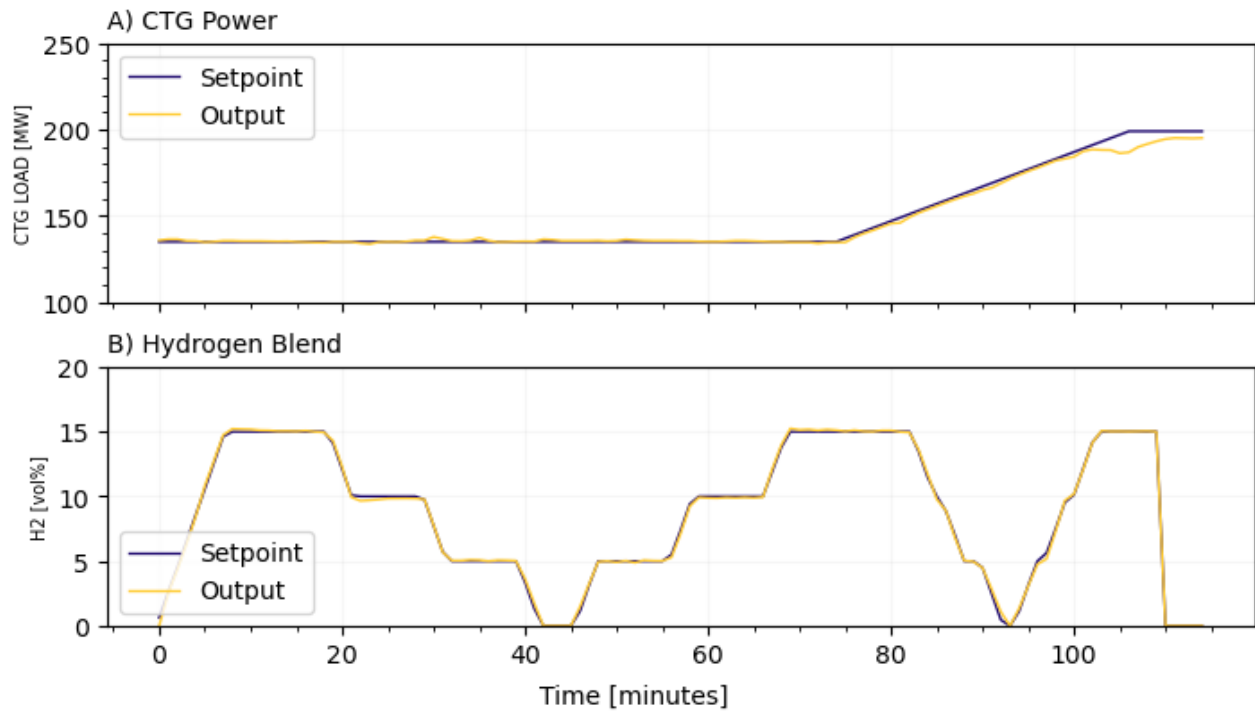


Figure 5-1: Test 1, CTG Power and Hydrogen Blend Outputs.

Test 2 was completed over the course of 2 days. The first half of Test 2 was completed during the second day of testing whereas the second half was completed on the first day of testing. In Figure 5-2, the red-shaded area from 0 to 70 minutes represents the second day of testing that was transposed in the figure to align with the test plan CTG power and hydrogen blend profiles. All subsequent Test 2 results have been adjusted in the same way and are presented without the shaded area. The test was completed after 140 minutes of operation and data collected after this point is included in the figure.

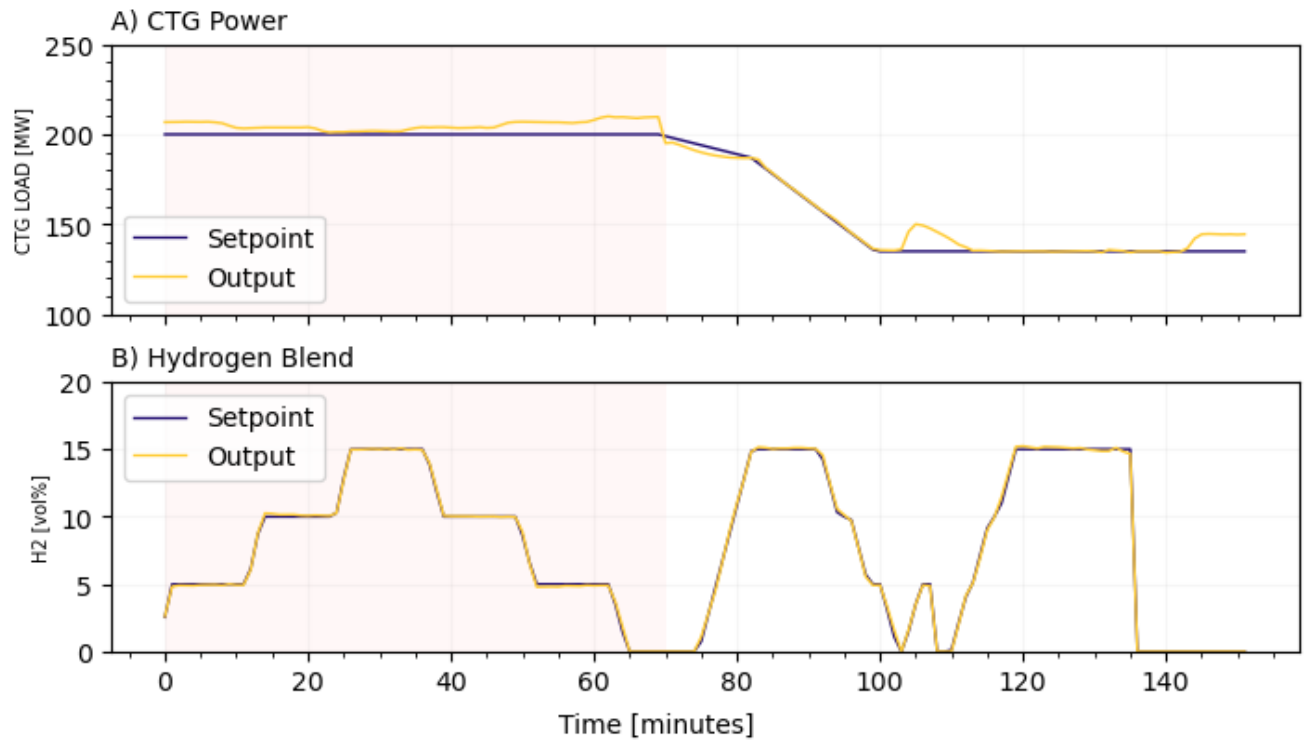


Figure 5-2: Test 2, CTG Power and Hydrogen Blend Outputs.

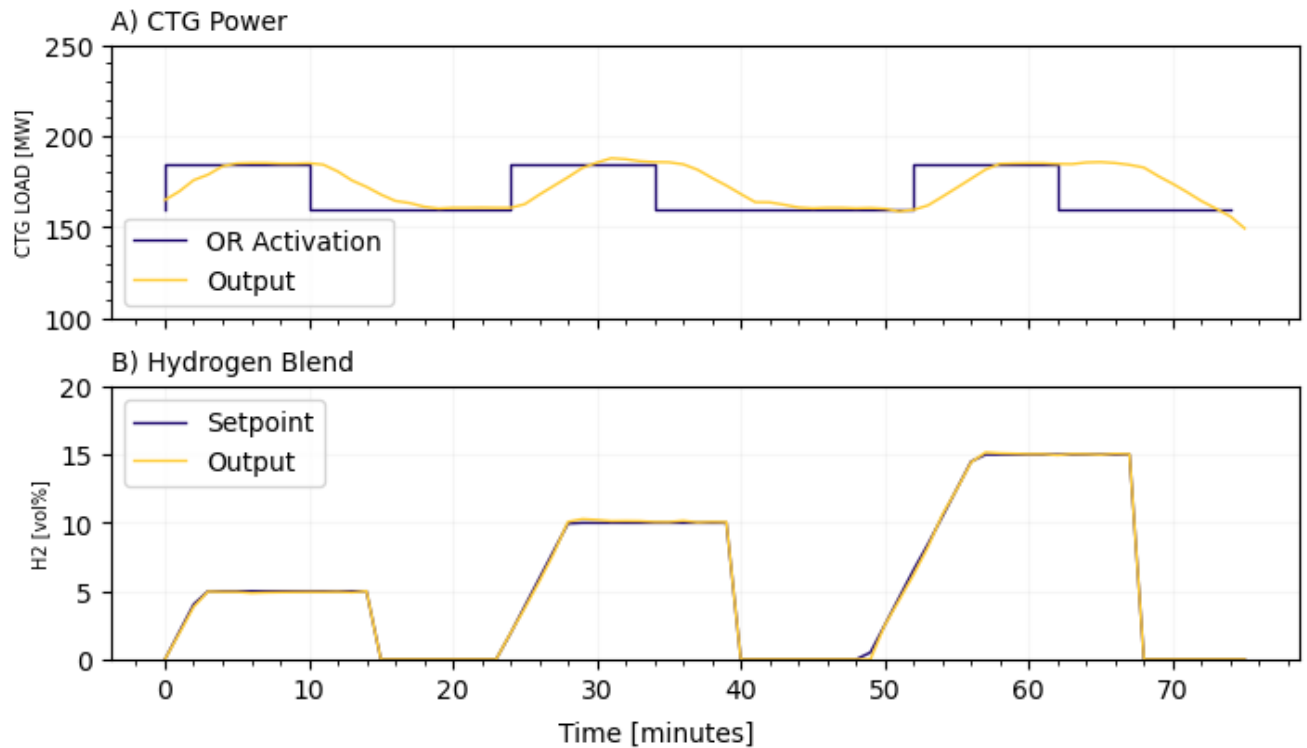


Figure 5-3: Test 3, CTG Power and Hydrogen Blend Outputs.

Figure 5-3 A) demonstrates the activation and deactivation of Operating Reserve (OR) whereby a signal is transmitted to the generator by the IESO and the CTG is needed to respond within 10 minutes. A summary of activation response times is provided in Table 5-2. The OR Activation Time is the elapsed time corresponding to the x-axis in Figure 5-3. The Time from the OR Activation to +25MW is the relative time it took the CTG to respond. All response times were observed to be within 10 minutes.

Table 5-2: Response Time of CTG.

H2 (vol %)	OR Activation Time (min)	Generator Output at Time of OR Activation (MW)	Time from OR Activation to +25MW (min)
5	0	164.9	5
10	24	160.6	6
15	52	159.5	7

5.2 CTG Emissions – CO₂

Figure 5-4 to Figure 5-6 contain aggregate data related to CO₂ emissions for corresponding CTG load and hydrogen blending outputs. In each test, the CO₂ emissions reduction curves (absolute in subplot D and percentage in subplot E) were similar to the hydrogen blending profile. The similarities between the CO₂ emissions data and hydrogen blend profiles were expected and are reflective of the combustion chemistry, that is, by replacing carbon-based fuel with hydrogen (which is not carbon based) the consequent combustion products have less carbon dioxide.

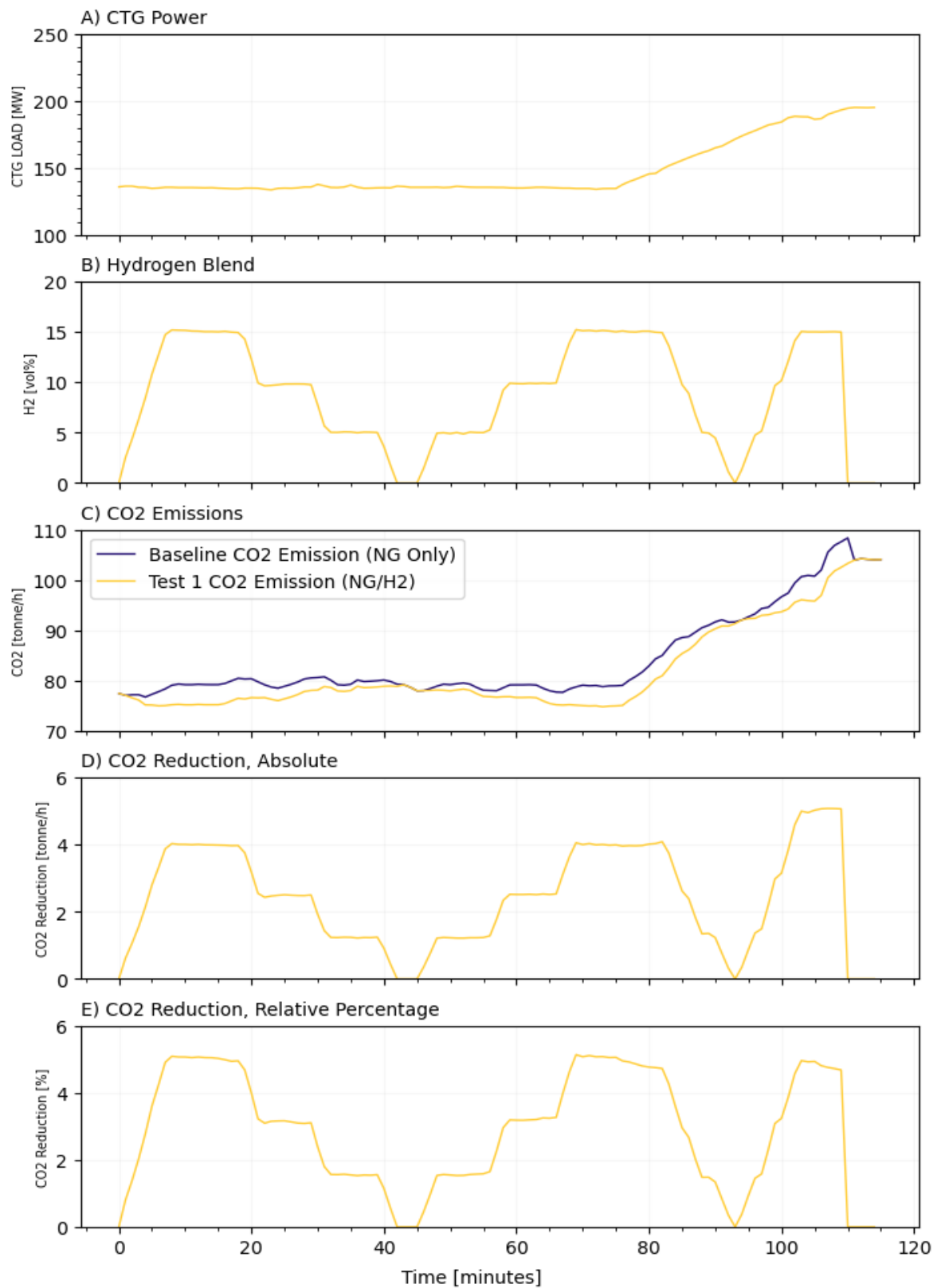


Figure 5-4: Test 1, CTG CO₂ Emissions Under Non-Blending and Blending Conditions, Instantaneous Absolute CO₂ Reduction and Relative Reduction Percentage to Baseline.

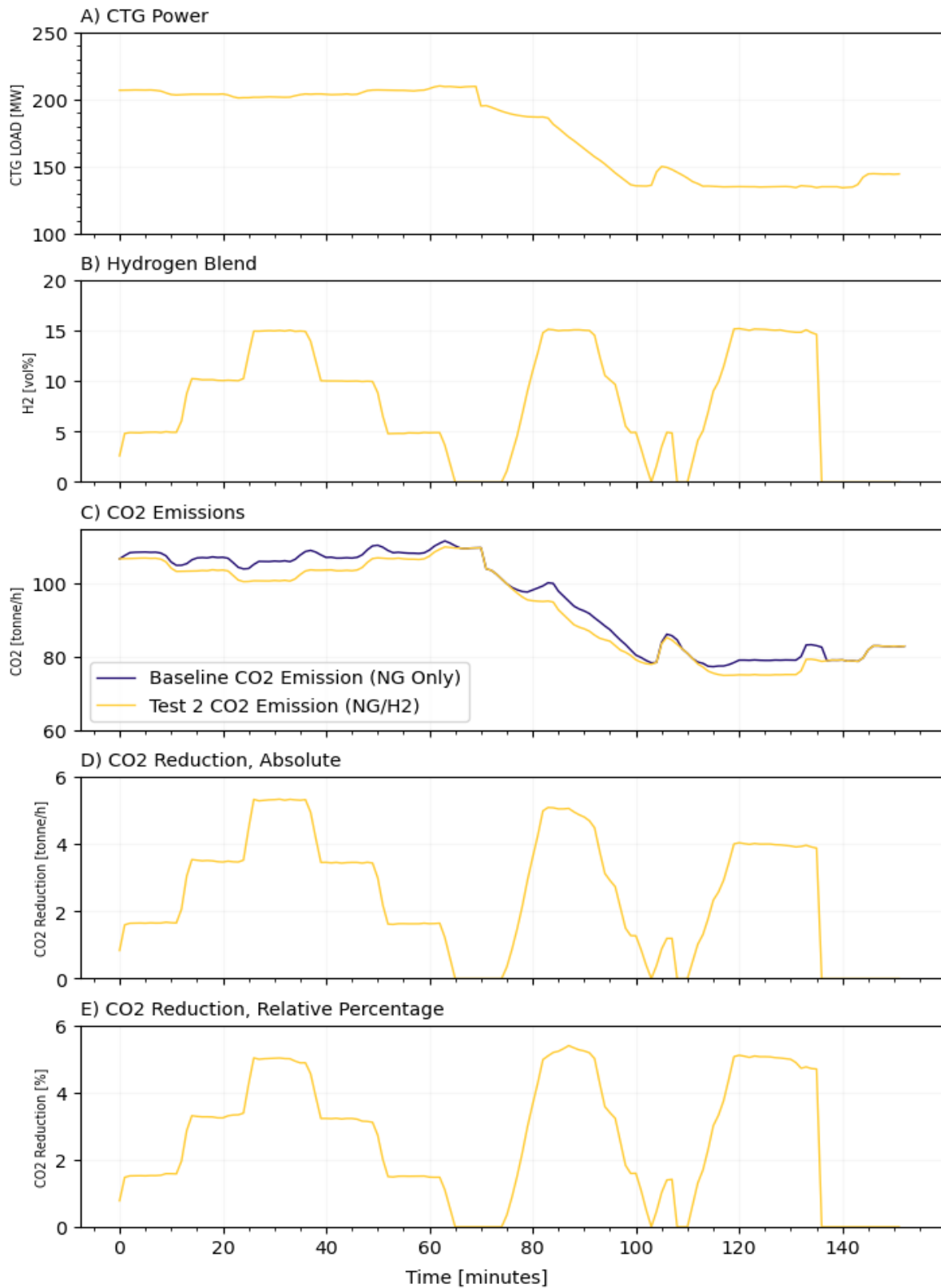


Figure 5-5: Test 2, CTG CO₂ Emissions Under Non-Blending and Blending Conditions, Instantaneous Absolute CO₂ Reduction and Relative Reduction Percentage to Baseline.

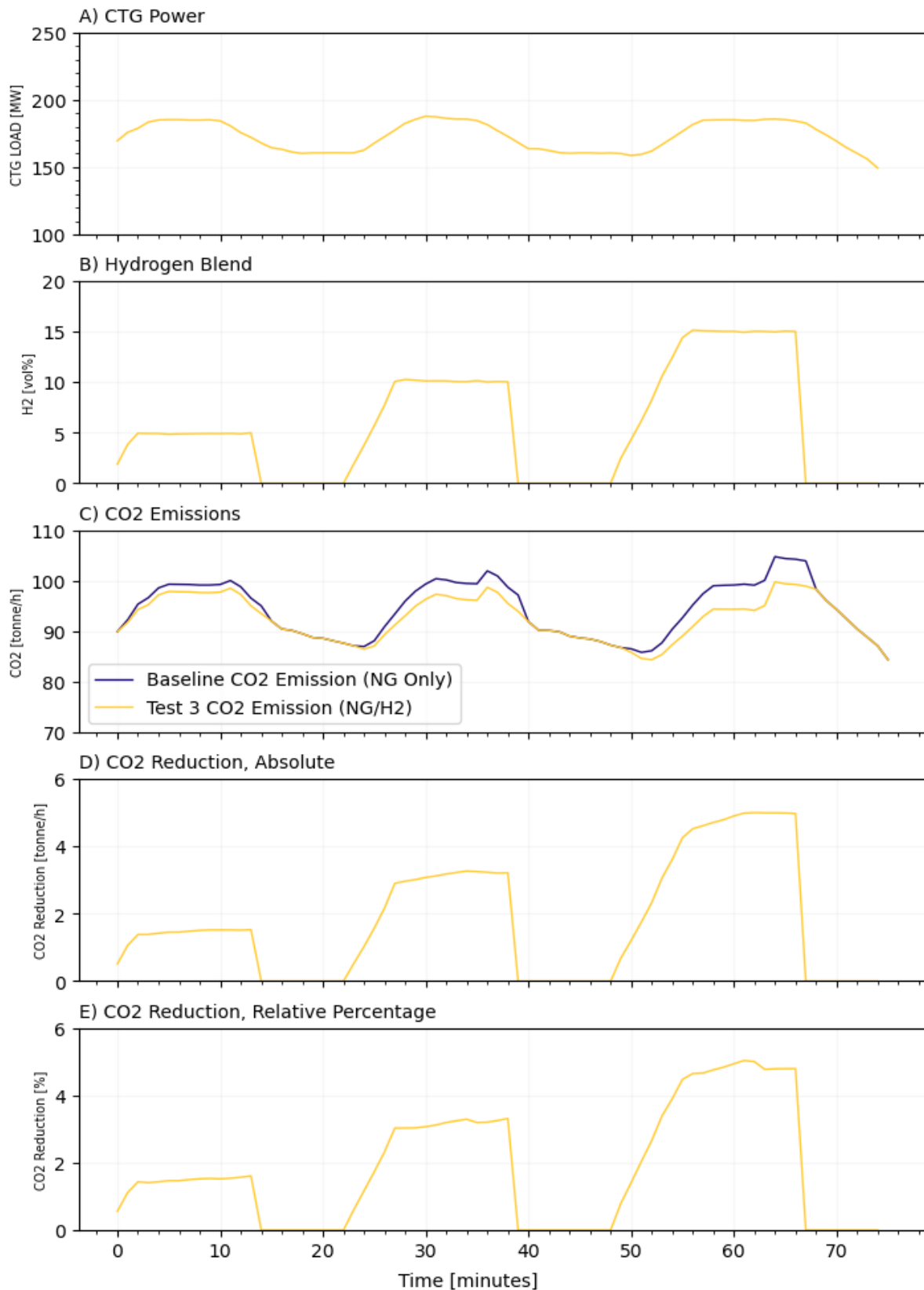


Figure 5-6: Test 3, CTG CO₂ Emissions Under Non-Blending and Blending Conditions, Instantaneous Absolute CO₂ Reduction and Relative Reduction Percentage to Baseline.

The baseline and actual emissions profiles are presented in subplot C) of Figure 5-4 to Figure 5-6. While the overall profile trends are similar, a measurable difference demonstrates the CO₂ reduction achieved through hydrogen substitution.

The general correlation between the hydrogen blending percentage and CO₂ reduction from all testing datapoints has been plotted in Figure 5-7. In the hydrogen blend range of 0 vol% to 15 vol% the relationship is linear with good alignment with the regression curve (i.e., "goodness-of-fit" is high with $R^2=0.997$). The grouping of points at 5, 10 and 15 vol% hydrogen blend is due to the quantity of data points collected at steady state operation. Conversely, the areas between these 3 (three) hydrogen blend percentages represent transient operation and are, therefore, more spread out.

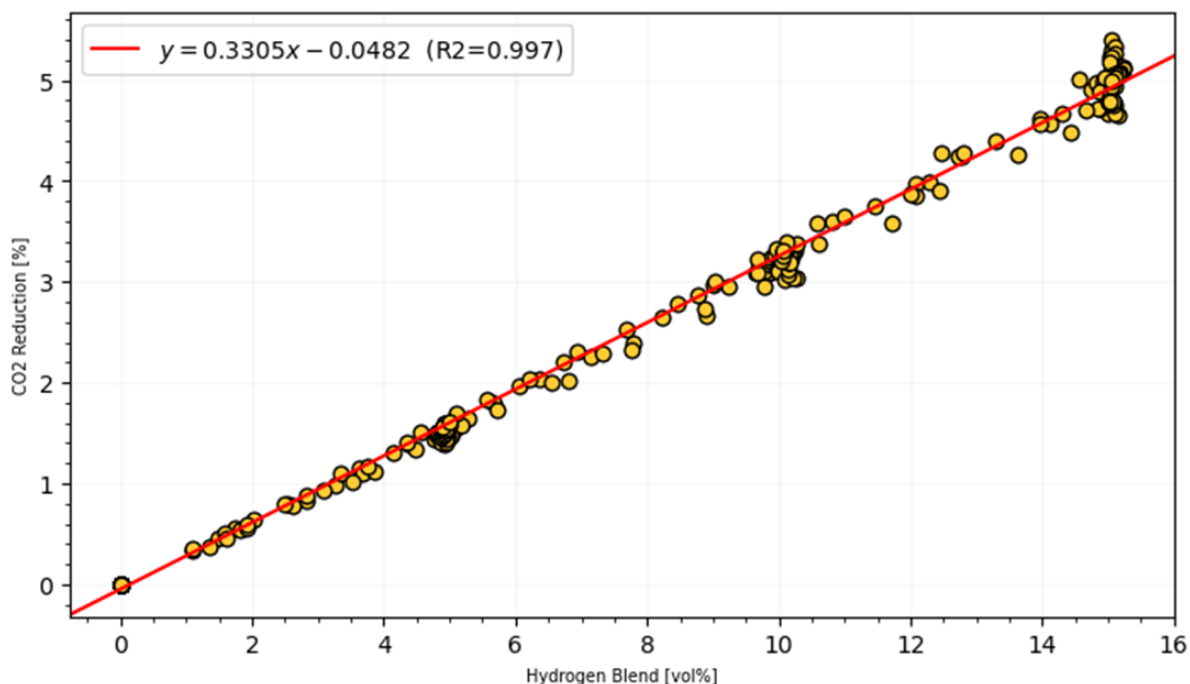


Figure 5-7: Hydrogen Blend Percentage (by Volume) and Relative CO₂ Reduction Correlation, Combined Tests.

5.3 CTG Emissions – NO_x and CO

The NO_x and CO emissions were also of interest during the test and captured on a time basis from plant instrumentation in the CTG stack. The respective NO_x and CO emissions for all three tests are presented in Figure 5-8 to Figure 5-10. The collected data shows minor variability of emissions with respect to CTG Load and hydrogen blend outputs between cases, which is within normal operating variability. During steady state operation where the hydrogen blend was constant, variations in NO_x and CO emissions were observed within tests and between them. Localized peaks appeared when the CTG power was varied, as seen in subplots C) and D) of Figure 5-8, were not present in the same subplots in Figure 5-10. This is typical operating behaviour for the CTG and is within expectations.

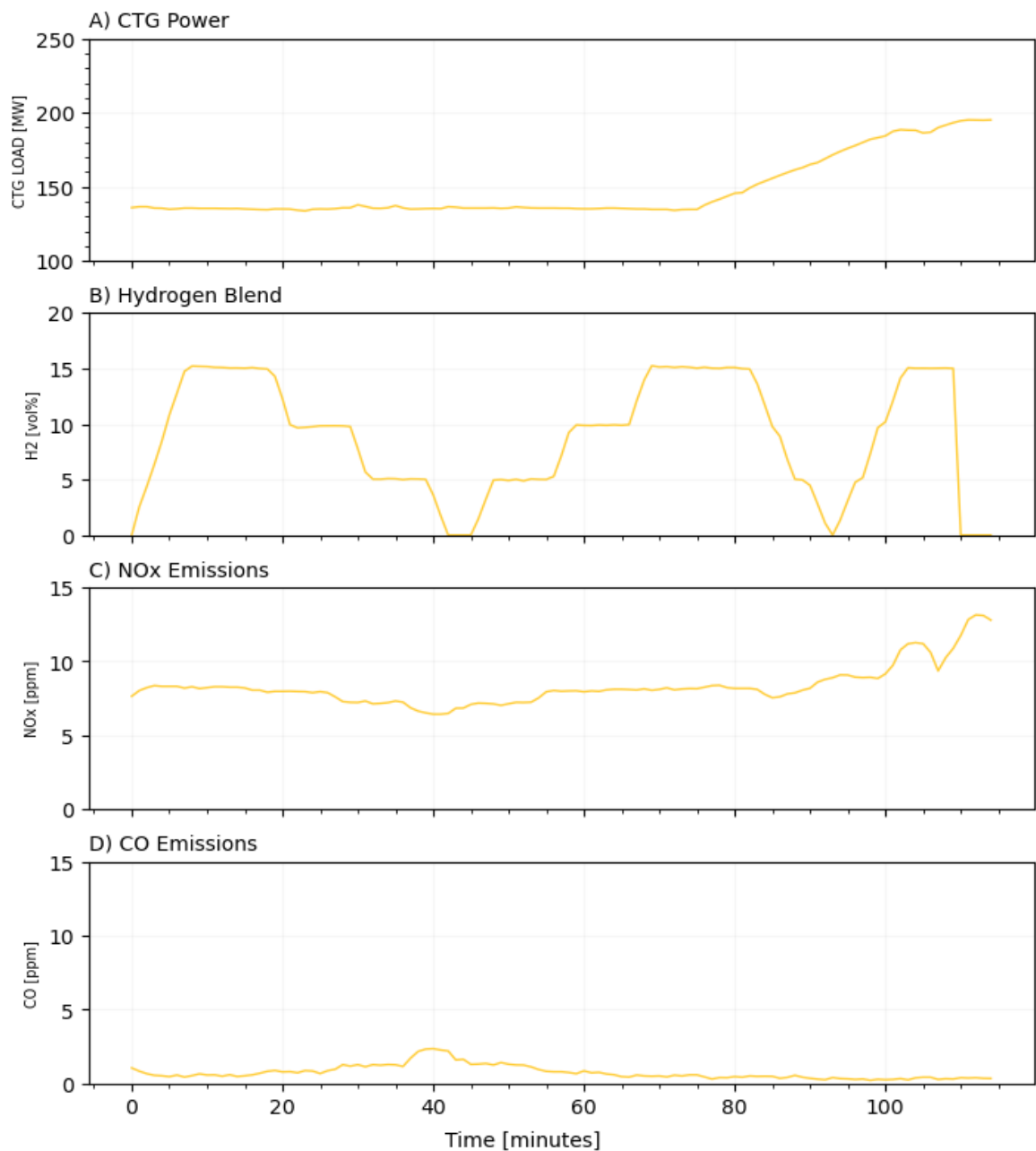


Figure 5-8: Test 1, NO_x and CO Emissions.

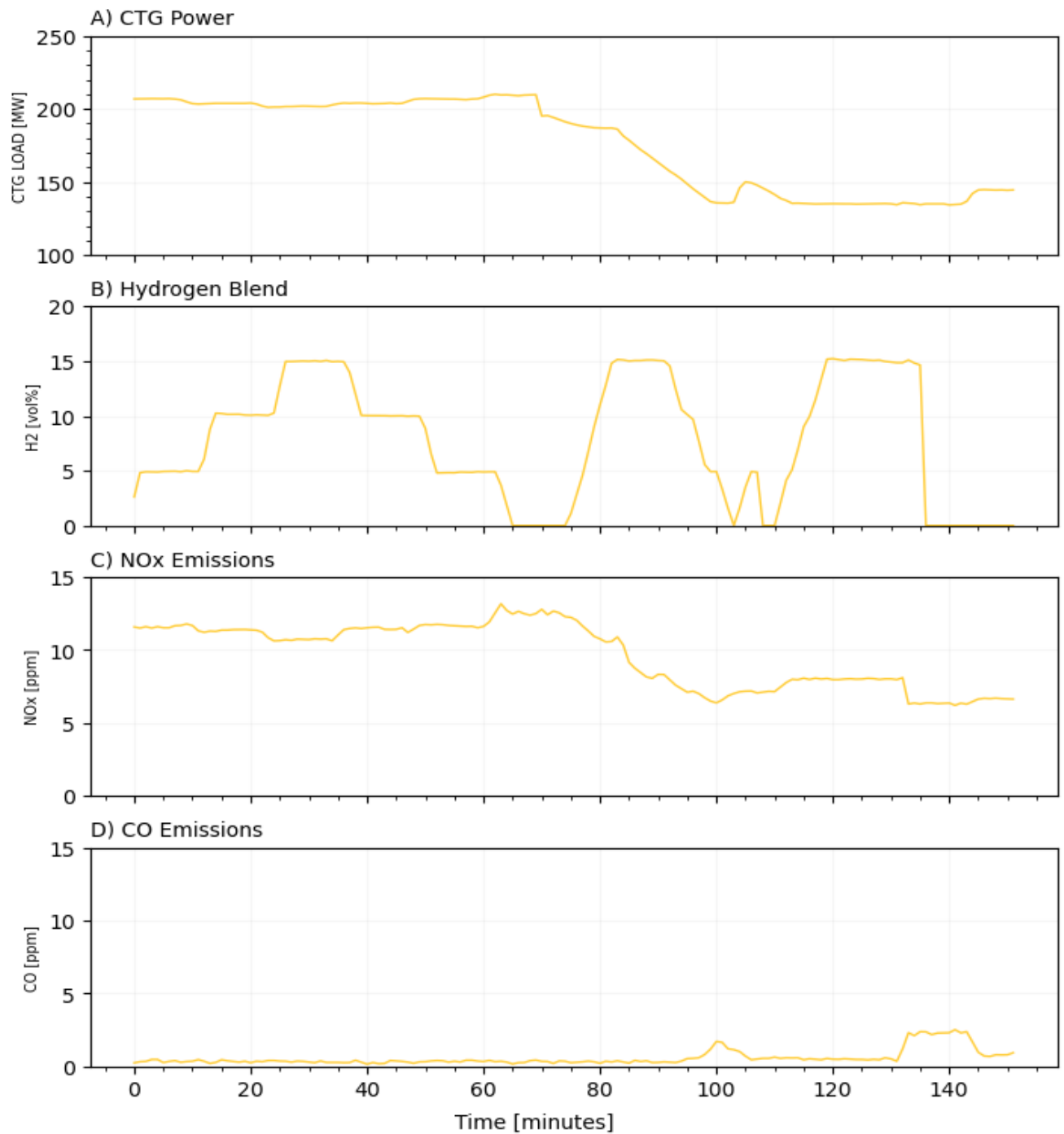


Figure 5-9: Test 2, NO_x and CO Emissions.

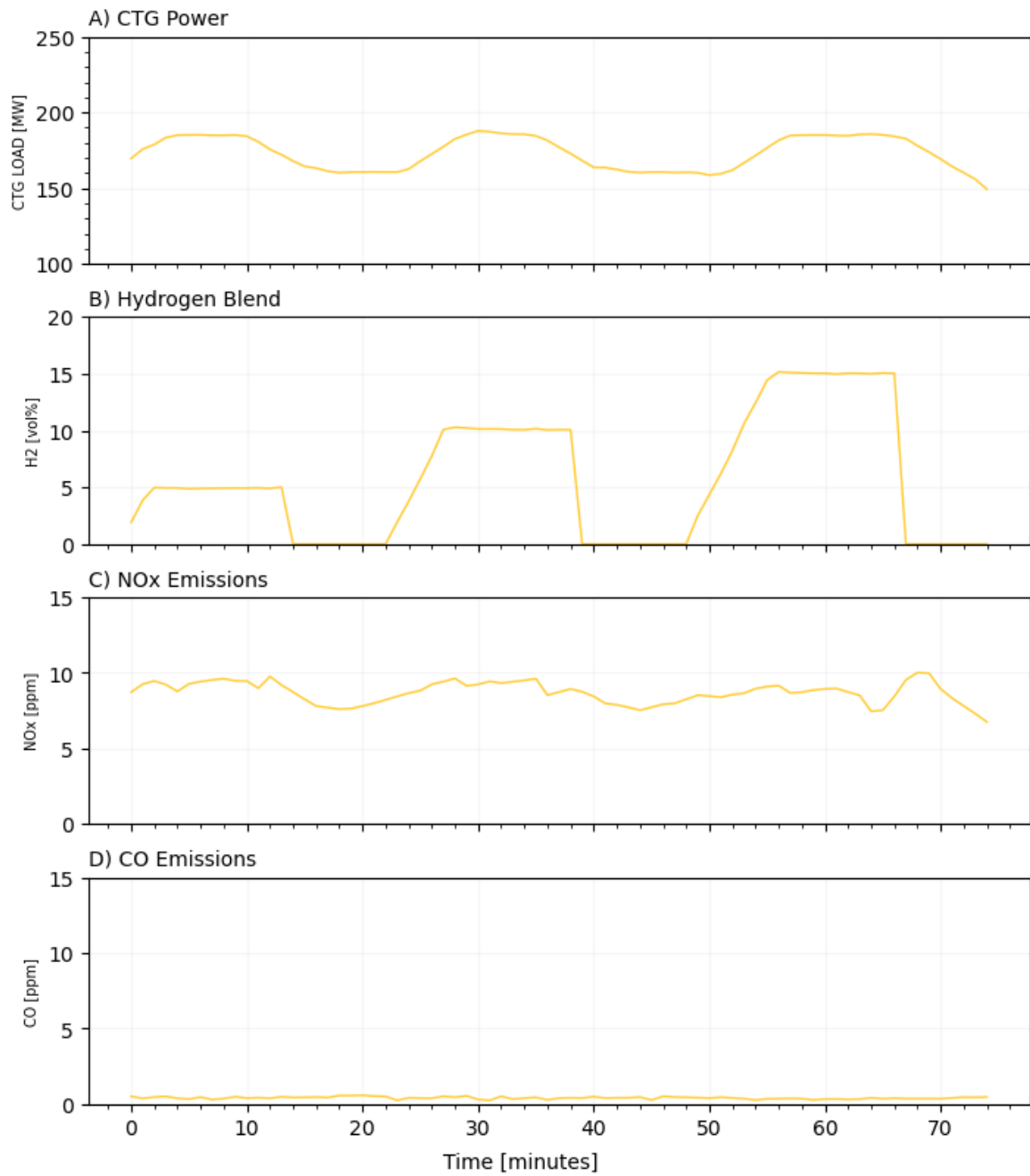


Figure 5-10: Test 3, NO_x and CO Emissions.

NO_x emissions, presented in Figure 5-11, are between 6 and 14 ppm with varying hydrogen blend percentage and slightly converging with increased hydrogen content, but resulted in a low fit relative to the trendline ($R^2=0.0016$).

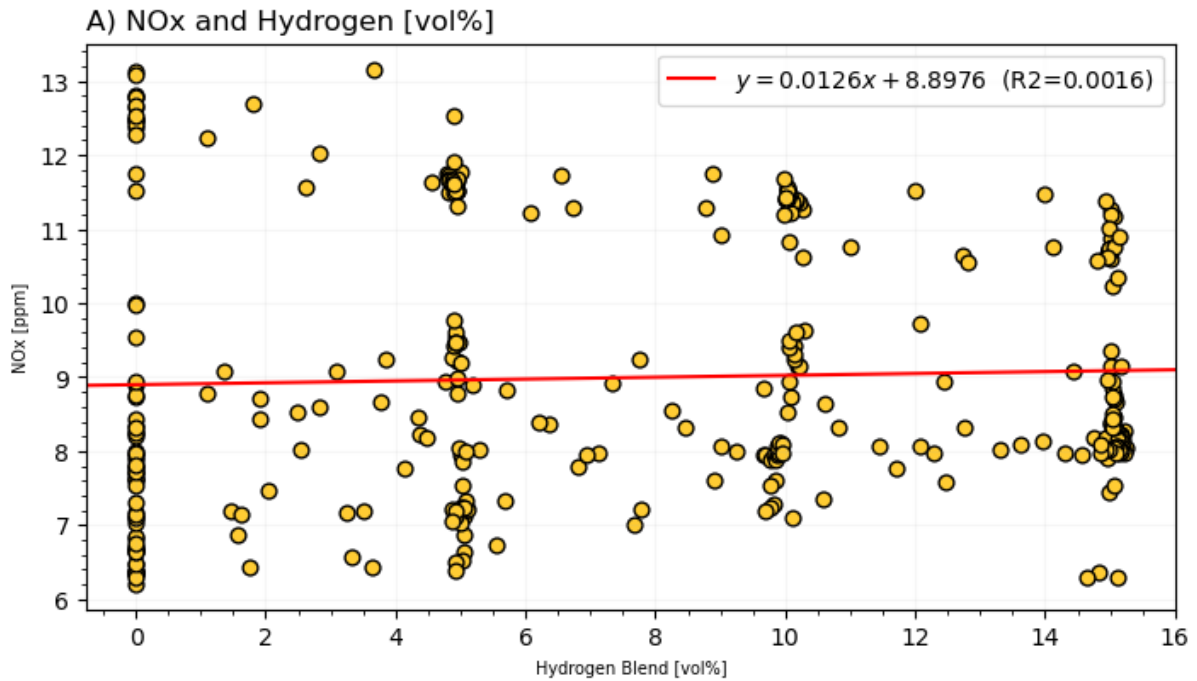


Figure 5-11: NO_x Emissions with Respect to Hydrogen Blend Percentage.

A negative trendline slope between CO and hydrogen blend percentage was observed with low fit ($R^2=0.0649$) and presented in Figure 5-12. CO emissions vary between 0 and 2.6 ppm with respect to the hydrogen blend percentage and converge with higher hydrogen content (at 15 vol% three outliers are seen between 2 and 2.5 ppm).

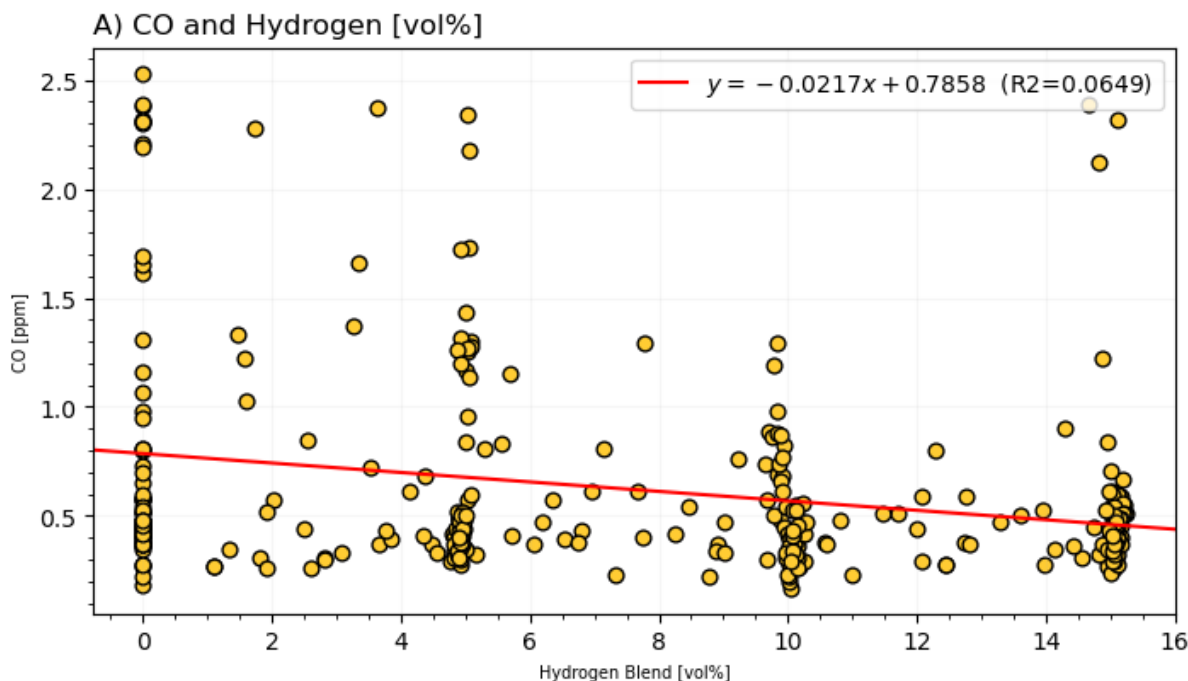


Figure 5-12: CO Emissions with Respect to Hydrogen Blend Percentage.

5.4 CTG Heat Generation and Heat Rates

CTG heat generation was also calculated during the three tests. Figure 5-13 to Figure 5-15 present the collected data from Tests 1, 2 and 3. The heat generation was calculated using turbine performance outputs recorded by the control system—principally fuel flow, turbine firing temperature, and generator load and Heating Values (LHV) of the fuel gas. The heat generated is dependent on the fuel blend provided into the system and by the power generation; as such, the heat generation profile is expected to track the CTG power output.

The heat generation is not a measurement of exhaust heat or HRSG inlet energy, although it correlates with those values. The temporary field instrumentation installed for the demonstration did not include burner metal temperature or flame-dynamics sensors; therefore, the computed heat generation value is the approximate indicator for combustion-system behaviour under hydrogen blending conditions.

During the trials, peaks were observed in the CTG heat generation during steady state operation after ramping events. This is most clearly observed in Test 3, (Figure 5-15 subplot C), where CTG heat increases a few minutes before the hydrogen blend percentage is decreased. Since no changes are being made to the CTG power or hydrogen blend percentage, the peaks are likely linked to other parameters in the CTG that were not recorded during these tests, such as the internal temperature, etc..

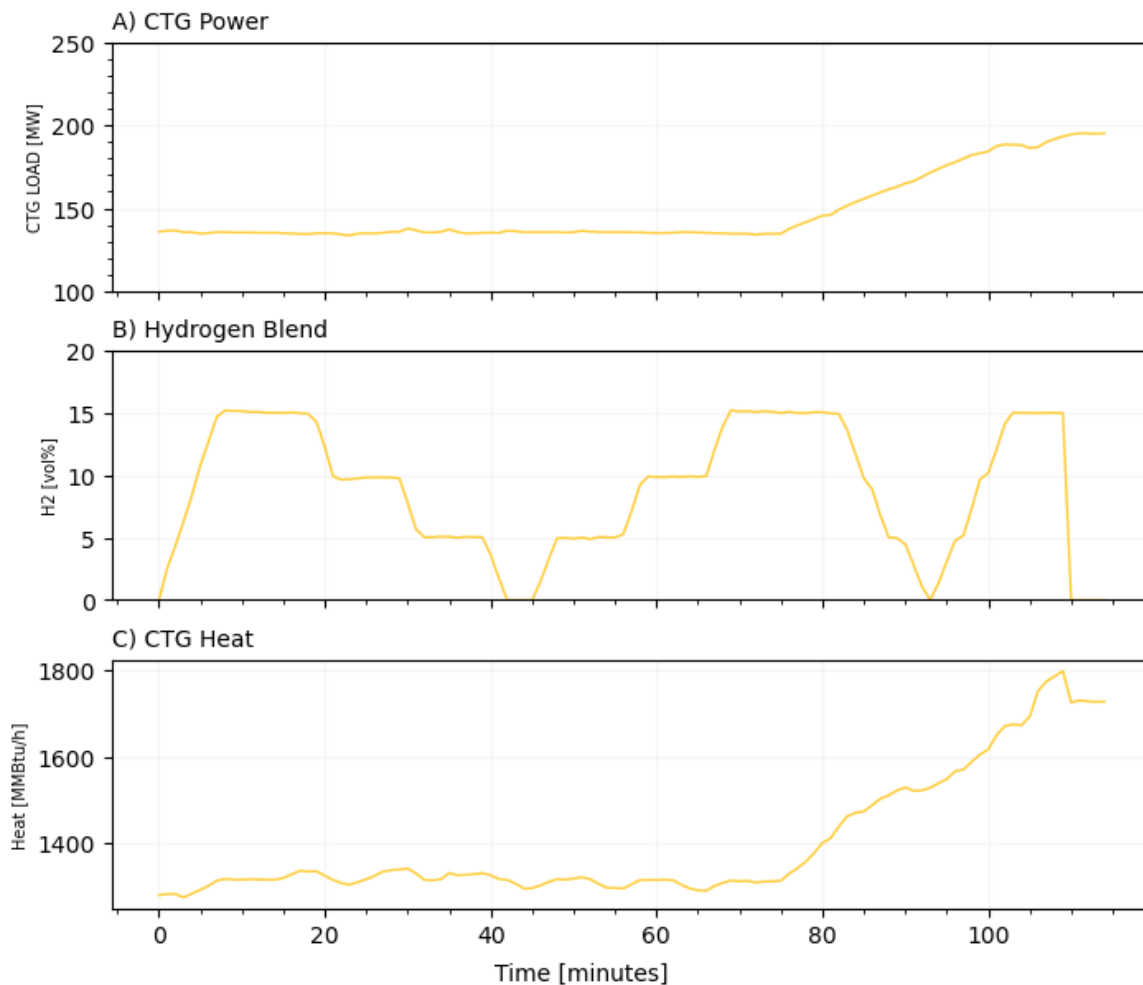


Figure 5-13: Test 1, CTG Heat Generation.

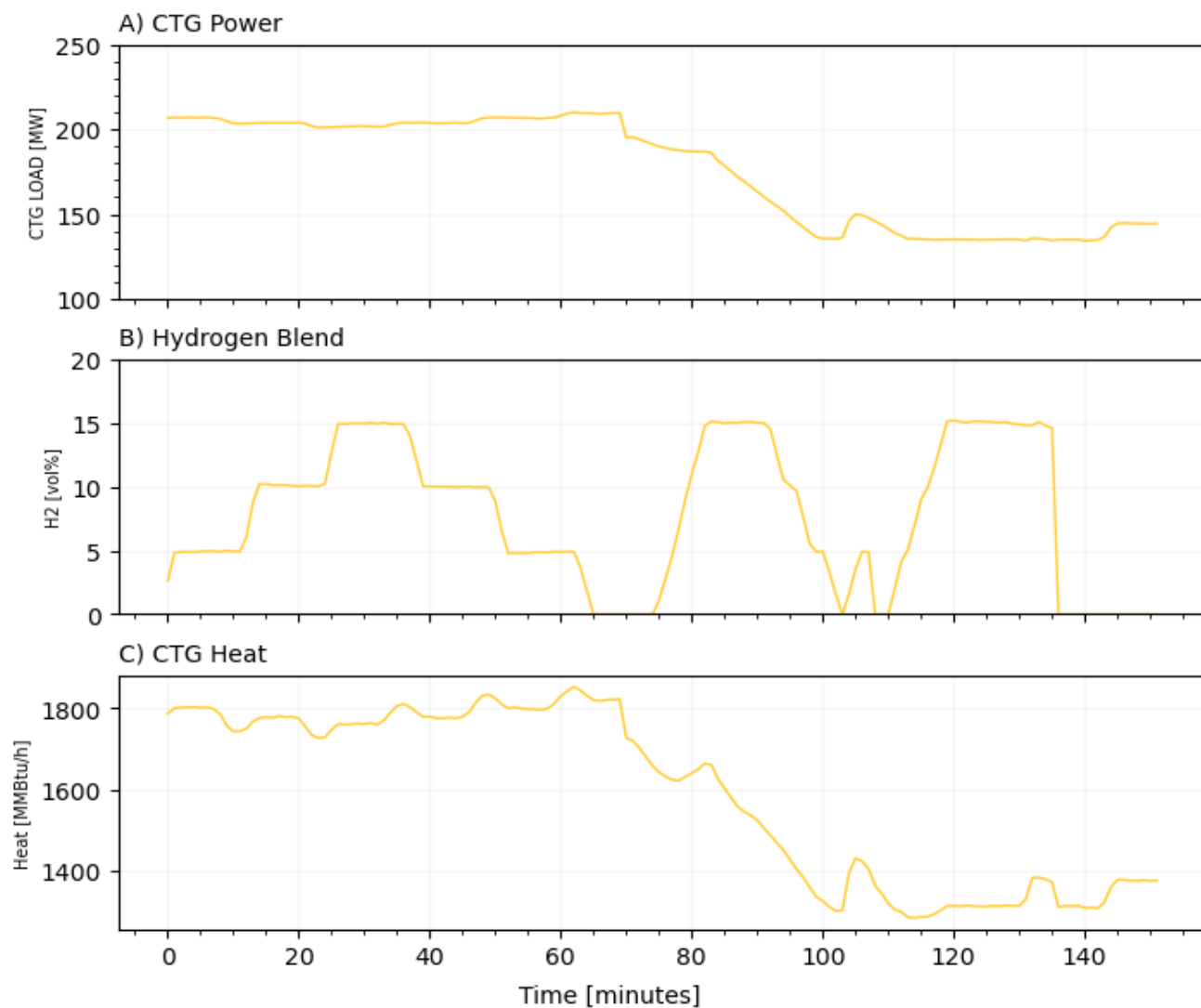


Figure 5-14: Test 2, CTG Heat Generation.

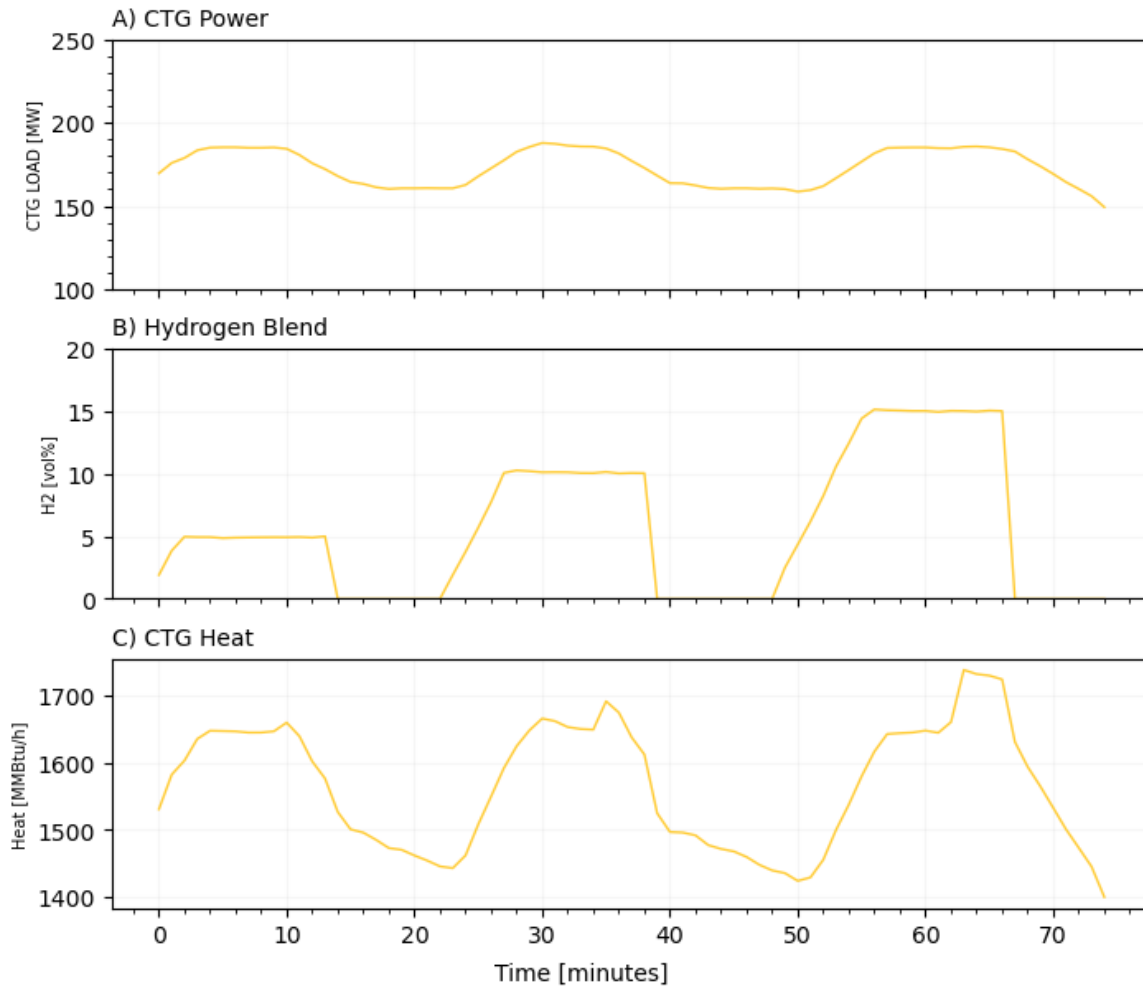


Figure 5-15: Test 3, CTG Heat Generation.

The heat rate for the CTG was calculated from the recorded data during tests 1 to 3 and plotted in Figure 5-16. The data points were divided into two groups characterized by a CTG power generation threshold of 185MW. The basis for this threshold was to observe heat rate near the Baseload CTG power output (subplot B) independent of the MLP or transitional heat rates (subplot A).

A wider band of heat rates, ranging between 8.5 and 10.5 MMBTU/MWh (LHV basis), was observed when CTG power was less than 185MW. When the CTG power was restricted to greater than 185MW the heat rate ranged from 8.5 to 9.5 MMBTU/MWh between 0 vol% to 15 vol% of hydrogen. At hydrogen blends of 0 vol%, 5 vol% and 10 vol% the range was smaller, typically within 8.5 and 9.0 MMBTU/MWh, however, at 15 vol% more variation was observed – approximately between 8.5 to 9.5 MMBTU/MWh.

The experimentally obtained heat rate was used to calculate the cost per MWh in Section 7.

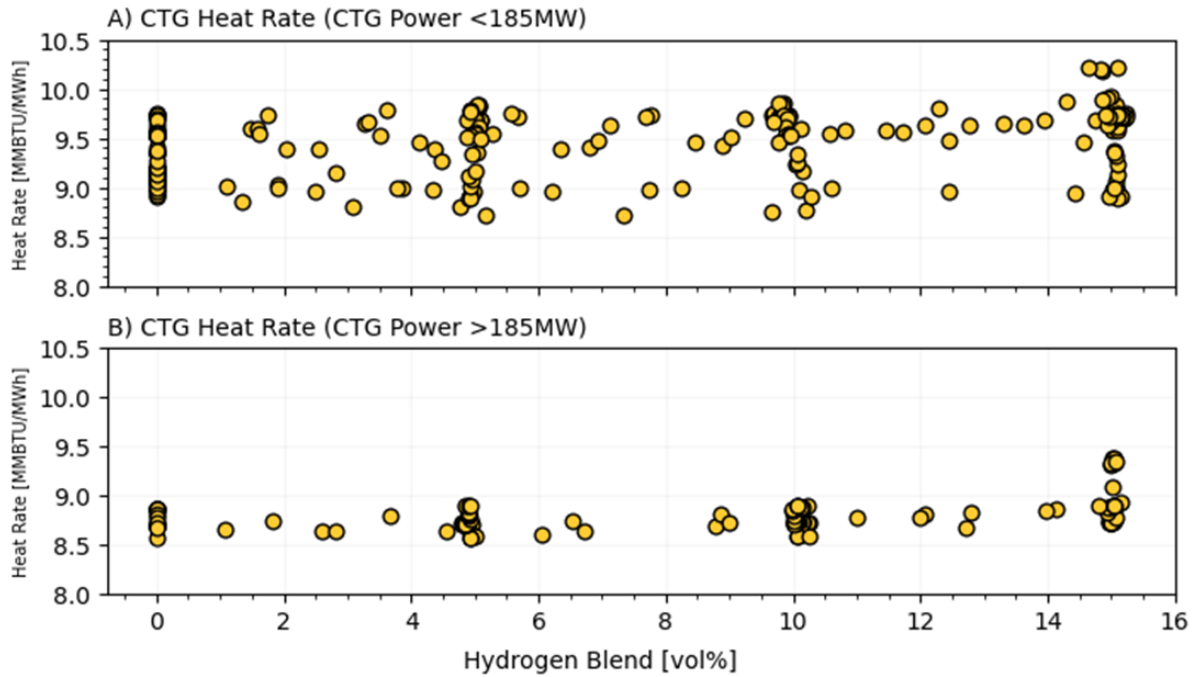


Figure 5-16: Tests 1-3, CTG Heat Rate.

5.5 STG Power and HRSG Efficiency

The resulting impact on surrounding operations including HRSG Efficiency and STG Power were captured over the duration of the trials. The respective HRSG Efficiency, STG Power, and CTG Exhaust Temperature for all three tests are presented in in Figure 5-17 to Figure 5-19 and show minor to no changes with respect to the CTG load and hydrogen blend results between cases. This is because it would take long term hydrogen operation to have a substantial impact on the downstream systems. The trials performed herein, were not over a long enough period to materially change the power or efficiency of the STG and HRSG respectively.

Recall that Test 2 was completed over 2 days, and the red-shaded area between 65 and 75 minutes in Figure 5-18, subplot D), represents the time where the dataset transitions from day 2 to day 1. The immediate drop-off is a result of the dataset merging and emphasizes the discontinuity of the tests independent of CTG power output and hydrogen volume percent between the two days.

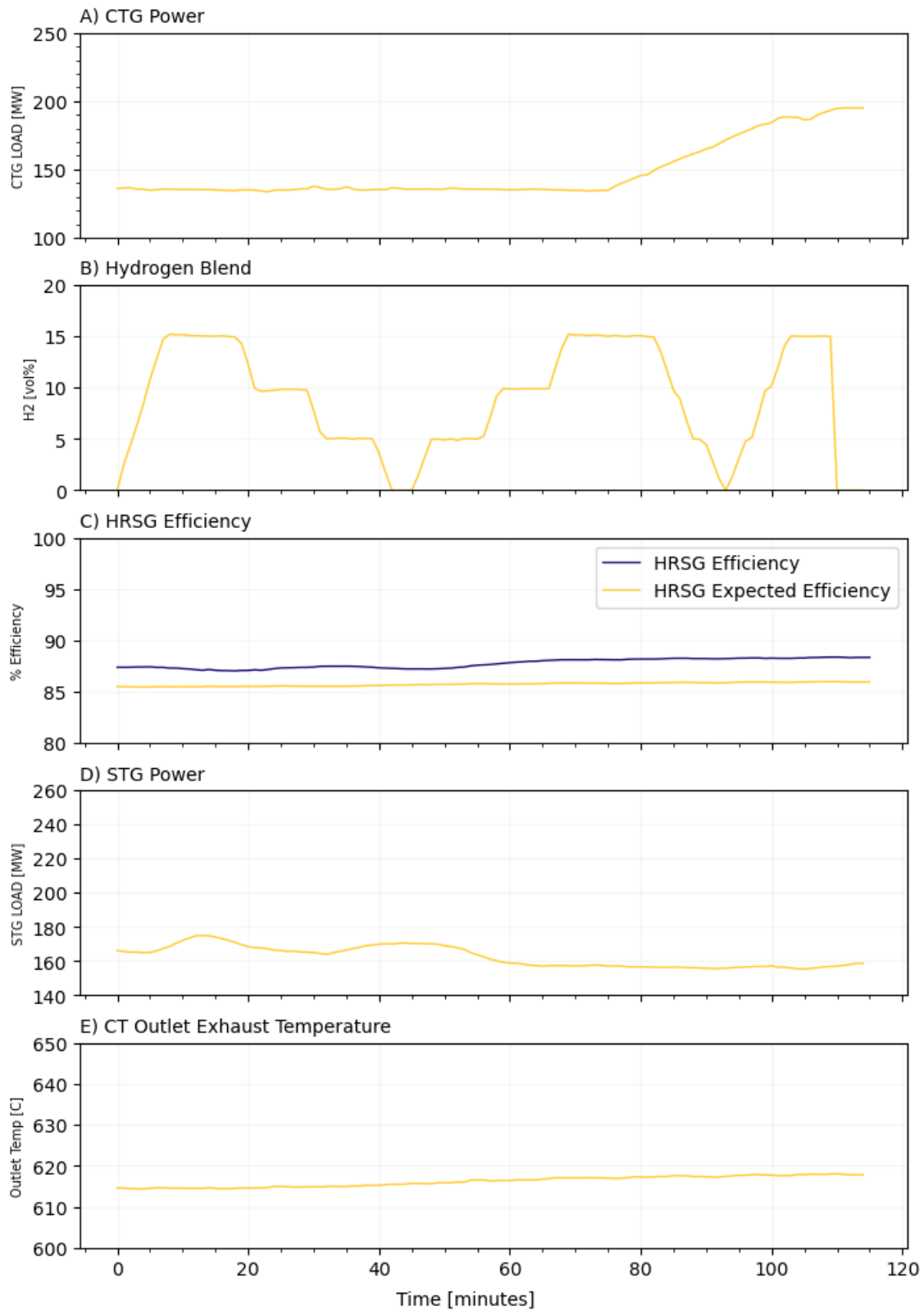


Figure 5-17: Test 1, HRSG Efficiency, STG Power, and CT Outlet Exhaust Temperature

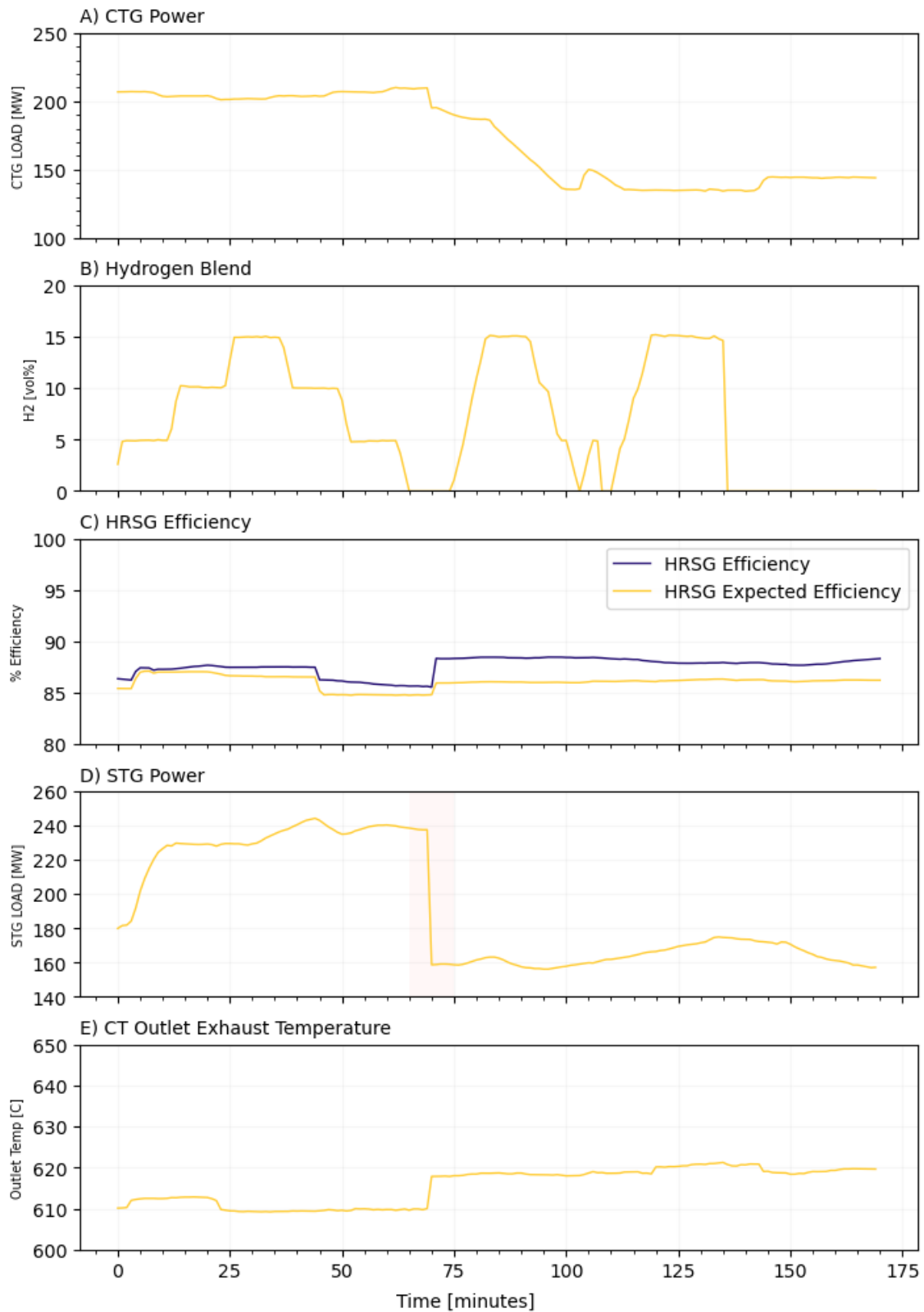


Figure 5-18: Test 2, HRSG Efficiency, STG Power, and CT Outlet Exhaust Temperature

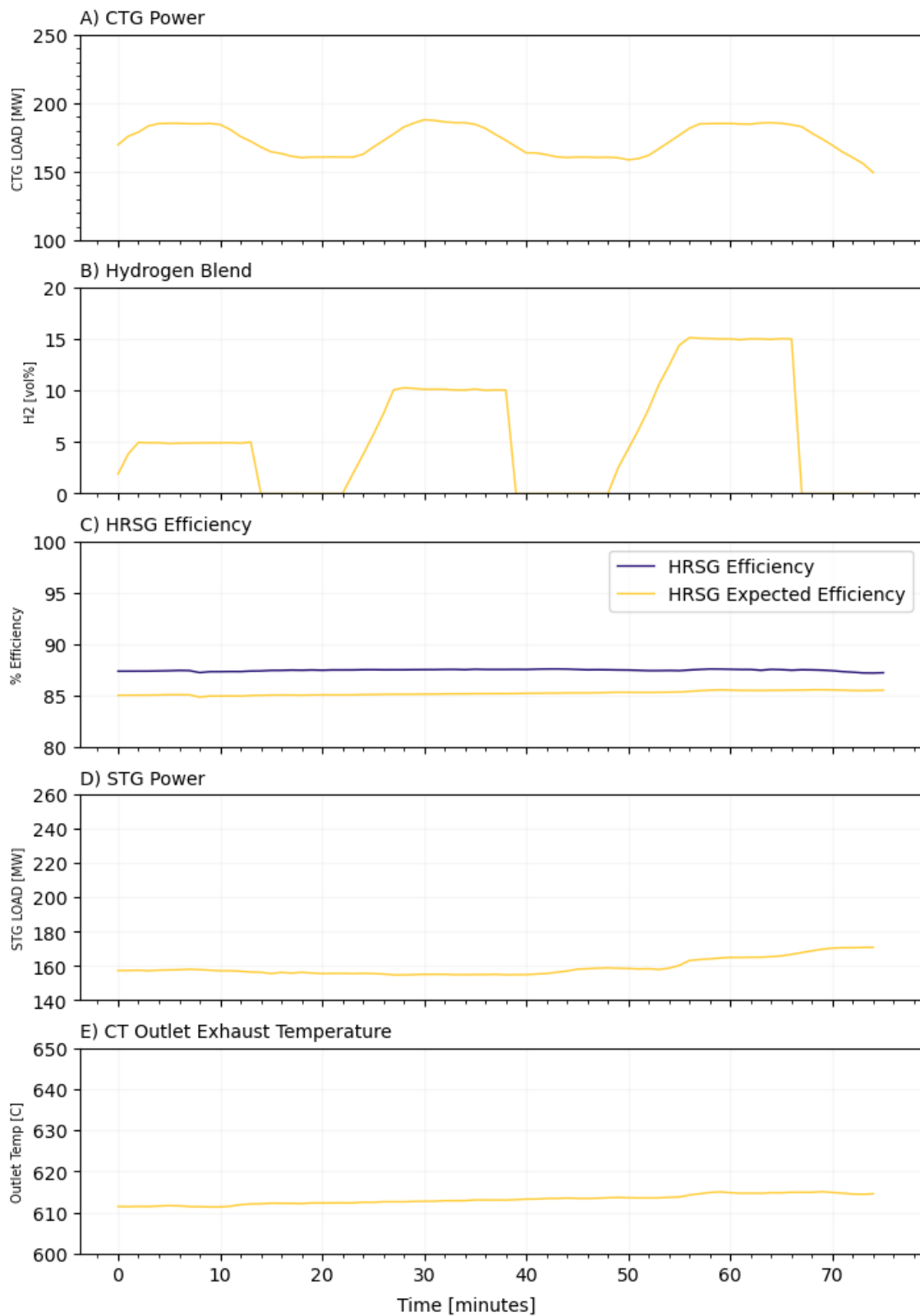


Figure 5-19: Test 3, HRSG Efficiency, STG Power, and CT Outlet Exhaust Temperature.

6. Discussion

6.1 Derating of the Gas Turbine During Hydrogen Co-firing

When operating under hydrogen co-firing conditions, the gas turbine power output must be reduced as the hydrogen ratio increases to maintain combustion stability and prevent overheating of physical components. This intentional derating also offsets the tendency to generate higher NO_x emissions when hydrogen was blended into the CTG fuel. The derating of the CTG power for hydrogen co-firing operation lowers the firing temperature as measured at the turbine outlet (turbine outlet temperature is a continuously monitored variable that is an input to the de-rating function in the control system). The required degree of derating was established by S-E through combustion testing and commissioning activities prior to the formal hydrogen blending tests. Derating curves based on ambient conditions and hydrogen content were established to operate the CTG in a stable and predictable manner.

S-E is able to optimize the performance through additional testing with local (temporary) instrumentation to monitor actual burner metal temperature and flame dynamics which was outside of scope for this project. S-E plans to utilize the burner test setup and combustion dynamics testing on future projects with hydrogen co-firing to minimize/remove the derating. In general, the CTG power derate is proportionate to the hydrogen blend percentage. For example, at 0 vol% hydrogen gas there is a 0% derating and with a 15 vol% a derate of up to 5.8% is expected.

Data collected in Test 2 demonstrated the impact of CTG derating. In Figure 5-2 subplot A), the CTG power was observed to change inversely to hydrogen concentration while operating at the Baseload. It should be noted that Test 1 was operating at MLP (i.e., the CTG power is at its lowest) and the system was not de-rated.

6.2 CO₂ Emissions Reduction

The relationship between hydrogen volume percentage and CO₂ emissions reduction is non-linear due to differences in fuel properties and system behaviour across a full hydrogen blend range of 0 to 100 vol% [R5]. Hydrogen possesses a lower volumetric energy density than natural gas; therefore, a given hydrogen volume fraction represents a smaller proportion of the total heat input, particularly at lower blending levels [R6]. As a result, initial increases in hydrogen content yield modest reductions in CO₂, while higher concentrations produce disproportionately greater benefits.

The substitution of hydrogen for natural gas is governed by both mass and energy ratios rather than volume alone, resulting in a non-linear trend across the full hydrogen blend range [R7]. Additionally, turbine derating, combustion stability, and burner temperature constraints influence the effective energy contribution of hydrogen, further reinforcing this non-linear relationship [R8]. Consequently, CO₂ reduction plotted against hydrogen volume percentage follows a polynomial trend. The data presented in Figure 5-7 exhibits a linear trend, consistent with expected results for blends up to 15 vol% hydrogen. Non-linear behaviour typically becomes apparent once the blend ratio exceeds approximately 50 vol% [R5]. Therefore, increasing the blend to 30 vol% may still maintain a linear relationship when testing the emission characteristics of the CTG (i.e., with a limited operation of 30 vol% hydrogen).

6.3 NO_x & CO Emissions Reduction

The CTGs at HHGS are equipped with ultra-low-NO_x (ULN) burners, which minimizes nitrogen oxide emissions without requiring water or steam injection. As NO_x and CO formation are dependent on combustion temperature, higher hydrogen concentrations would typically increase NO_x due to hydrogen's higher flame temperature. However, the opposite trend was observed, and is attributed to intentional system derating as discussed in Section 6.1. The turbine's power output was reduced as hydrogen was introduced to lower the flame temperature for flame stability and protect burner components within safe temperature limits. During commissioning, the turbine was tuned to incorporate automated control logic to manage these effects automatically. As a result, NO_x emissions during hydrogen co-firing are comparable to, or lower than, those produced under natural gas-only operation, as demonstrated in Section 5 Results and Analysis.

7. Economic Impact, Technical Impact, and Risk Assessments

7.1 Economic Impacts

For the purposes of the economic analysis, the spot price for natural gas and hydrogen are compared. An evaluation of the capital costs for net new infrastructure, delivery and transportation service costs for both fuels, normalized to the power output, are required to do an accurate comparison and is beyond the scope of this report.

Natural gas remains the benchmark for cost-effective dispatchable generation in Ontario, typically priced at **\$2–\$4/GJ**. In contrast, hydrogen presents a significantly higher cost profile:

- **Hydrogen used in the demonstration project (15 vol%)** was procured at **\$17/kg**, translating to **\$120/GJ for hydrogen** and **\$4.50-\$6/GJ for the blended gas**.

For natural gas power plants, electricity market offer prices is primarily driven by fuel costs and conversion efficiency (heat rate). For HHGS, which operates as a combined cycle natural gas facility, the baseline marginal cost is relatively low when fueled solely by natural gas. However, hydrogen blending introduces a substantial increase in fuel cost, which directly affects offer pricing.

The demonstration project relied on temporary infrastructure and mobile hydrogen logistics. Transitioning to a firm, stable supply would significantly reduce fuel costs and improve operational reliability but requires cost sharing or contract mechanisms to support hydrogen cost recovery.

To illustrate this, we compare the marginal cost per megawatt-hour (MWh) for natural gas and hydrogen using their respective higher heating values (HHV) and Heat Rates at Baseload operation as the required fuel input:

Table 7-1: Marginal Cost for Natural Gas and Hydrogen Composition.

Case	H2 (vol%)	NG (vol%)	Fuel HHV (MJ/kg)	Heat Rate (GJ/MWh) [MMBTU/MWh]	Marginal Cost (\$/MWh)
NG only	0	100	54.55 ²	9.24 ⁷ [8.76]	18-37 ⁴
Hydrogen Blending Project (Project Supply)	15	85	56.36 ³	9.12 ¹ [8.64]	40-58 ⁵
Hydrogen Blending Project (Future Target Price)	15	85			24-42 ⁶

Notes:

- 1) Experimental value, Baseload conditions (i.e., CTG power >185 MW)
- 2) NG HHV: 54.55 MJ/kg (38.85 MJ/Sm³)
- 3) H2 HHV: 141.7 MJ/kg (12.08 MJ/Sm³)
- 4) NG Cost: \$2-4 /GJ
- 5) H2 Cost – current: \$17/kg
- 6) H2 Cost – Future Target Price: \$4.50/kg
- 7) Heat Rate for a single turbine, not for the entire (combined cycle) HHGS facility

Table 7-1 shows that currently blending hydrogen at 15% by volume represents a **57-122%** increase in marginal costs compared to natural gas.

As hydrogen production technologies mature and economies of scale are realized, future target prices for hydrogen could reach \$4.5/kg, assuming hydrogen is produced via electrolysis and no incentives or environmental attributes are applied. This reduces the overall marginal costs; however, there is still a premium of **14-33%** the cost natural gas today.

Hydrogen at \$4.5/kg produces a marginal cost to generate electricity of **\$24-42/MWh** for a 15% hydrogen blended natural gas turbine. However, it requires a substantial buildout of hydrogen infrastructure and services for reliable operations. The project incurred additional costs relating to the mobile equipment, tube trailers, pressure let down trailers and technical field support that is not reflected in this price. Natural gas in Ontario today has the advantage of existing infrastructure with the capital costs being shared amongst the Rate Base and amortized over long periods of time. Hydrogen blending for power generation could be economically viable under the following conditions:

- Contractual mechanism for hydrogen cost recovery.
- Carbon pricing offsets (e.g., \$170/tonne CO₂e by 2030).
- Clean Fuel Standard credits

- Hydrogen production incentives (e.g., Clean Hydrogen Investment Tax Credit).

Without contractual support or market incentives, it limits the ability for a facility to contribute to reliability and emissions reductions and enable cost recovery.

7.2 Impact of Increased Service Intervals Due to Hydrogen Blending

Hydrogen blending introduces new operational dynamics that may affect maintenance schedules and long-term asset performance:

- Higher flame temperatures may accelerate wear on turbine components.
- Increased NO_x formation may require more frequent tuning and emissions control.
- Hydrogen's diffusivity can impact piping systems, seals, valves, and sensors.

Additional testing will need to be completed should hydrogen cofiring systems be retrofitted in existing assets, the scope of which is beyond this report. Further, the projected cost increases to support hydrogen blending must be incorporated into long-term O&M budgets and CES recovery frameworks.

7.3 Technical Impacts

7.3.1 Turbine Performance

Operational data from the hydrogen blending trials demonstrated that the CTG maintained stable operation across all tests, both at MLP and Baseload conditions. The turbine exhibited stabilization, within three minutes of hydrogen introduction or removal, and demonstrated load-following capabilities at fast and slow ramp-rates.

More information regarding the setpoints and ramp-rates can be referenced in Appendix 1. Automated interlocks ensured safe shutdown during low-pressure conditions or hydrogen trips, enabling seamless transition back to 100% natural gas without impacting turbine stability. These enhancements allowed the blending system to respond accurately during steady-state operation, load ramps, and hydrogen depletion scenarios.

Heat Rate improved at higher CTG loads consistent with NG-only operation, with heat generation closely tracking power output and hydrogen blend profiles. Overall, the system demonstrated reliable combustion stability and effective control response under varying hydrogen blending conditions making this operation feasible for commercial operation.

7.3.2 Combustion Characteristics and Emissions

Hydrogen co-firing required intentional derating of the CTG to control the internal temperature of the turbine and thereby maintain flame stability, as hydrogen's higher flame temperature increases combustion temperature. CTG derating maintained combustion stability while protecting burner components.

During commissioning, the turbine's burner tuning and control logic were refined to automatically regulate firing temperature. Consequently, NO_x emissions during hydrogen co-firing were observed to

be comparable to or lower than natural-gas-only operation. CO₂ emissions followed a linear reduction trend up to 15 vol % H₂, however it is predicted that at a hydrogen blend greater than 50 vol% this result would be positive non-linear. Refer to Section 6 more information regarding the Combustion Characteristics and Emissions trends observed during this trial.

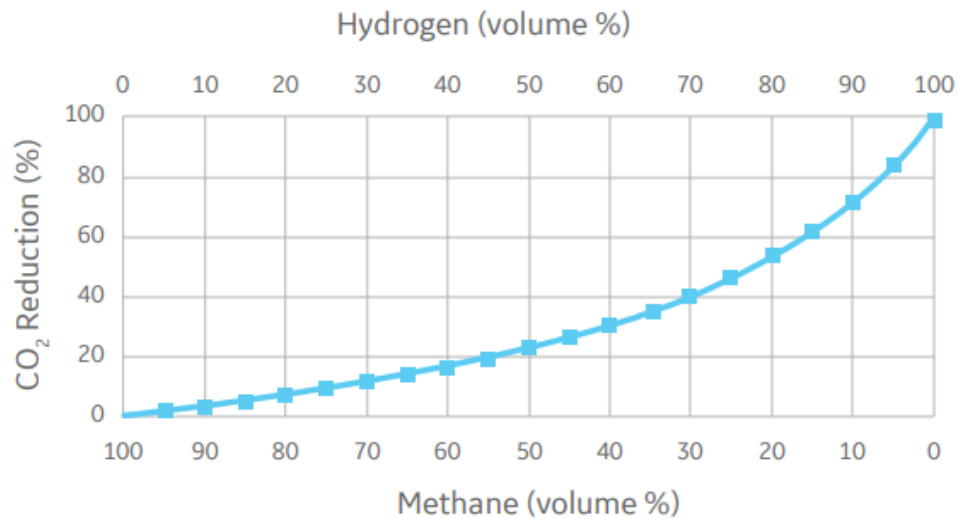


Figure 7-1: Predicted relationship between CO₂ emissions and hydrogen/methane fuel blends (volume %) [R-5].

7.4 Risk Assessment

7.4.1 Operational Risks

Operational risks identified during the hydrogen blending trials primarily relate to hydrogen measurement, supply continuity, and CTG burner integrity.

The inability to install the Wobbe meter due to CRN restrictions required manual gas sampling, which delayed verification of hydrogen blend ratio. Potential safety hazards when taking samples given hydrogen's high diffusivity were addressed by safe working procedures.

Hydrogen supply interruptions also presented operational challenges. Delays in tube-trailer refilling and transport led to adjustments in the trial schedule, demonstrating the need for contingency measures and flexible scheduling to maintain testing continuity. Maintaining consistent hydrogen quality and delivery is essential to ensuring reliable turbine performance and emissions control.

Finally, derating the turbine introduced an operational risk to the existing facility of not being able to fully meet its capacity as on 100% natural gas. Derating was required to protect burners from overheating and degradation when hydrogen was introduced to protect the turbine component life. Future operations should investigate utilizing 100% hydrogen burners and monitor the internal temperature to prevent degradation during hydrogen co-firing.

7.4.2 Safety Risks

Hydrogen is a colourless, odorless gas that forms explosive mixtures with air over a wide range of hydrogen-air ratios (5%-75%). In addition, the ignition energy is very low making it particularly dangerous in an industrial environment. Hydrogen has a low density in comparison to air making buoyant and quick diluting in the event of a release in an outdoor environment. Finally, hydrogen as a molecule is much smaller compared to methane or other gas, making it prone to leaks. Explosion protection, using proper area classification (via the electrical code), must be integral to the design, especially around potential leakage areas of a hydrogen piping system, such as flanges, valves and instrumentation.

The following table compares the characteristics of hydrogen with methane:

Table 7-2: Hydrogen and Methane Property Comparison.

Parameter	Unit	Methane	Hydrogen
Relative Density (to air)	-	42%	7%
Diffusion Coefficient (20°C)	cm ² /s	0.21	0.76
Lower Explosion Limit (LEL)	-	5%	4%
Upper Explosion Limit (UEL)	-	15%	75%
Autoignition Temperature	°C	537	560

Health and safety measures guided the entire system design process, with special focus on planning and execution. A comprehensive hazard and operability study (HAZOP) and process hazard analysis (PHA) was conducted with all recommendations implemented. Consequence modelling and a dispersion assessment was undertaken to minimize risk to the plant.

During setup, commissioning, and testing, safety protocols were implemented to ensure safe operation within the hydrogen environment. A no-phone and no-sparking-tool policy mitigated ignition risks, while continuous site-wide communication via walkie-talkies enabled real-time coordination between the control room and field personnel. Morning meetings were conducted with all parties to discuss daily activities, along with afternoon meetings to discuss daily learnings and areas for improvement. These check-points allowed for effective communication between the parties by dedicating time to ensure alignment and address concerns held by any personnel.

The new hydrogen system was pressure tested (as required by TSSA and relevant code) before the system was purged and filled with hydrogen using established procedures. After the system was charged with hydrogen, the system was kept under positive pressure to ensure there was no air ingress.

Throughout testing, and days between testing, the system pressure was monitored to ensure that the pressure was constant (i.e., no leaks). Potential leakage areas like pipe flanges were wrapped with hydrogen-sensitive tape, which changes colour when in contact with hydrogen gas. The hydrogen tape was monitored via plant personnel every day during their normal rounds, and before and after testing. Through the design and construction phases, local fire departments were engaged as well as Municipal

authorities to educate personnel about the site and the hydrogen trials including the safety measures being implemented.

8. Conclusion and Recommendations

The Halton Hills Hydrogen Blending Project successfully demonstrated the technical and operational feasibility of hydrogen co-firing in a commercial combined cycle gas turbine environment. Hydrogen blending into a functioning turbine supplying power to the IESO was achieved across the range of 0–15 vol%, with the turbine exhibiting stable performance and rapid recovery following hydrogen trips. This testing validates the operational potential for hydrogen integration into Ontario’s dispatchable generation fleet.

Operational data confirmed that CO₂ emissions reduction followed a linear trend within the tested range, achieving up to 5% reduction at 15 vol% hydrogen. While this relationship is expected to become non-linear at higher blend ratios, the trials provide a strong foundation for scaling to higher blend ratios in the future. The project also highlighted the necessity of turbine derating during hydrogen co-firing to maintain combustion stability and protect burner components, which simultaneously mitigated NO_x emissions.

Beyond technical validation, the project delivered critical learnings in permitting, safety, and stakeholder coordination. Atura Power gained valuable experience navigating regulatory requirements with the TSSA and implementing robust safety protocols for hydrogen handling. These insights will inform future hydrogen projects and support Ontario’s decarbonization objectives.

8.1 Recommendations

1. **Enable Economic Viability Through Market Design**

Introduce mechanisms within IESO-administered markets and CES contracts to recognize hydrogen as an eligible fuel. Key elements should include:

- a. Pass-through of incremental hydrogen fuel and maintenance costs.
 - b. Performance-based incentives tied to emissions reductions.
 - c. Integration of carbon pricing and clean fuel credits into settlement processes.
- These measures will allow generators to recover costs and participate competitively while supporting Ontario’s broader industrial decarbonization goals.

2. **Expand Testing Scope and Funding**

Provide funding and program flexibility for future trials that include:

- a. Expand funding scope for retrofitting existing assets (e.g. turbines) to accommodate higher blend ratios.
- b. Evaluation of hydrogen blends at 30 vol% or above

3. **Support Hydrogen Infrastructure Development**

The IESO should enable investment in permanent hydrogen infrastructure through targeted programs or RFPs and support cost reduction measures such as interruptible electricity rates for hydrogen production facilities. These steps will lower production costs, improve supply

reliability, and allow extended-duration blending trials, paving the way for commercial-scale adoption.

9. Lessons Learned

During the hydrogen blending trials, several key lessons were identified that will inform future operations and testing protocols.

Early verification of equipment compliance and certification: The Project found that many “off the shelf” components, while technically suitable for service, do not have the required certification(s) to be used in Ontario. For example, the Wobbe meter, intended for measuring gas composition, could not be installed due as it did not have an Ontario CRN. This necessitated manual gas sampling, which introduced additional safety and accuracy risks due to hydrogen’s low molecular weight and high diffusivity. Future projects should prioritize early procurement planning and regulatory review to confirm CRN compliance, ensuring that key instrumentation can be installed and commissioned as intended.

To meet the requirements of the CHIC, all gaseous hydrogen piping system components must have a minimum design temperature range of -40°C to 65°C. All piping and equipment was compliant with the CHIC with the exception of the control valves on each HBS; these valves had a lower design limit of -29°C. Due to this temperature limitation, to operate this equipment: (1) A variance was required from the TSSA to allow this equipment to be used as these valves are not code compliant; and (2) In order to guarantee that the lower temperature limit of this equipment was not exceeded, all testing had to take place at ambient temperatures that were above 10°C and safety systems were in place (and demonstrated to be functional to the TSSA) to shut down the system if hydrogen gas temperatures approached -29°C. The minimum ambient limit arose from a simulation of the predicted gas temperature (and sufficient margin) due to the cooling effect from adiabatic expansion during rapid tank decanting. If the hydrogen blending will be conducted in the future, the existing hydrogen control (metering) valves on the HBS will be required to be replaced with valves that meet the design temperature requirements stipulated in the CHIC.

Delays in hydrogen supply highlighted the value of flexible scheduling and proactive contingency planning. Tube trailer filling delays required more time than originally anticipated, shifting the trial schedule from every other day to every three days. Despite these challenges, the team adapted effectively, and due to positive progress with the hydrogen trials, the team was able to reallocate hydrogen volumes, and complete the trials ahead of schedule. This experience reinforced the importance of maintaining adaptable project schedules and strong interdisciplinary coordination when working with multiple suppliers and regulatory stakeholders.

Trials occurred during peak summer temperatures, a period when grid reliability was a primary concern for the IESO. Due to the tests coinciding with the hottest days of the year there was a concern that the IESO could have requested suspension of the hydrogen trials at any time to prioritize grid stability. In order to be preemptive, Atura Power had a specialized Energy Manager working in the control room to coordinate with the IESO. The team's proactive communication, providing the IESO with advance notice of trial activities and load changes, proved essential to maintaining grid stability and trust. This experience emphasized the importance of continuous coordination with external stakeholders, particularly when conducting grid-connected hydrogen testing during high-demand periods.

During the blending trials, strict safety measures were implemented to ensure safe operation in a hydrogen environment. A no-phone and no-sparking-tool policy was enforced to prevent ignition risks in the event of a hydrogen leak. Continuous communication across the site was critical to maintaining safety and coordination, walkie-talkies were effectively used to relay real-time updates between the control room and field personnel. This demonstrated the importance of clear and consistent communication protocols when operating in hydrogen environments.

Early engagement with the TSSA. The Canadian Hydrogen Installation Code (CHIC) has been adopted in the Province of Ontario for projects where hydrogen is used as a fuel and is enforced under the "Fuels Safety" division of the TSSA. The requirements within the CHIC are not well suited to industrial applications, leaving room for code interpretation by the designer and the AHJ; this can ultimately lead to confusion when planning a plant modification and/or installing new hydrogen related equipment. As such, early engagement with the TSSA and other potential AHJs (i.e., the fire department, building department, etc.) should be a requirement and is recommended for any fuels related hydrogen project during the early phases of engineering to establish an agreed upon design roadmap. Regular check-ins (with the TSSA in particular) as the project phases progress is essential to ensure that the project requirements are understood by all parties and that there are no "new" requirements based on differences in code interpretation and/or inspector judgement.

10. Next Steps

While the demonstration confirmed the technical feasibility of hydrogen blending, the next phase must address the economic and policy conditions required for commercial adoption. Current hydrogen costs remain significantly higher than natural gas, creating a barrier to market competitiveness. To overcome this, Ontario's market design should evolve to include cost recovery mechanisms, performance-based incentives for emissions reductions, and integration of carbon pricing and clean fuel credits. These measures will ensure hydrogen can transition from a pilot-stage fuel to a viable option for dispatchable generation.

Building on the outcomes of the trials, several areas have been identified for further investigation to enhance understanding of hydrogen co-firing performance and system behaviour.

Exploring hydrogen blend ratios up to 30 vol%: Additional testing is recommended to investigate a wider range of hydrogen blend percentages to characterize the relationship between hydrogen volume fraction and CO₂ emissions reduction.

Minimize or eliminate CTG Output Derate: The next phase of testing should include continuous monitoring of the turbine's internal component temperatures to allow for a more comprehensive assessment of the results and how hydrogen flame characteristics influence turbine performance and combustion dynamics compared to natural gas. These measurements should allow for the CTG output derate to be reduced or eliminated at different blend ratios.

Evaluating ambient temperature effects: Future trials to be conducted under a range of ambient conditions, particularly at lower temperatures, to assess how environmental variations impact turbine efficiency, stability, and emissions behaviour.

Analyzing exhaust temperature and performance over longer durations: Further analysis should be conducted to assess the impacts of hydrogen blending over longer durations. This should include evaluating the CTG exhaust conditions to determine how hydrogen co-firing affects overall steam production cycle over longer durations. This assessment will provide a more complete understanding of system wide impacts and identify any performance adjustments required to optimize efficiency under hydrogen-blended operation.

Implementing a permanent PRS: Future work should assess the design and integration of a permanent PRS into the facility. This installation would replace the temporary mobile pressure reduction skids used during the trials. A fixed installation would enable continuous operation and support future scalability for commercial hydrogen blending.

References

Ref No.	Document Name	Document Number	Revision
[R1]	Pathways to Decarbonization Pathways to Decarbonization		Dated: 2022
[R2]	Phase 1 IESO Blending Tests Summary Presentation	4480A-180-209-STND-0001	0
[R3]	Atura Power - HHGS H2 Blending (Co-Firing) Commissioning & Testing Report	21437	0
[R4]	Ontario Ministry of the Environment, Conservation and Parks - Verification Statement under Section 18 of Ontario Regulation 390/18 for 2024 Reporting Year	N/A	Dated: August 28, 2025
[R5]	Hydrogen for power generation Hydrogen for power generation	N/A	Dated: March 2022
[R6]	Hydrogen Gas Turbines ETN Global Report ETN-Global-Hydrogen-Gas-Turbines-Report-10-2024.pdf	N/A	Dated: October 2024
[R7]	Hydrogen Combustion: Features and Barriers to Its Exploitation in the Energy Transition Hydrogen Combustion: Features and Barriers to Its Exploitation in the Energy Transition	N/A	Dated: October 20, 2023
[R8]	Hydrogen in Combustion Turbine Electric Generating Units TSD - Hydrogen in Combustion Turbine EGUs.pdf	Docket ID No. EPA-HQ-OAR-2023-0072	Dated: May 23, 2023
[R9]	Hydrogen Strategy for Canada: Progress Report Hydrogen Strategy for Canada: Progress Report - Natural Resources Canada	N/A	Dated: May 2024

Appendix 1 – IESO Testing Operator Setpoints

The following section outlines the activities completed during the hydrogen testing. For each day, a comprehensive table summarizes the minute-by-minute activities, including parameters such as minimum loading point, run-time, and ramp rates. These tables provide a quantitative record of the operational setpoints.

Approximate time step of activities on IESO Test 1 Day 1

Test	Task	Description	Approx. Time of Step (mins)
1	CTG @ MLP load	Set at Minium Load Point (MLP) on CTG ~135MW	-
1	Ramp to 15 vol% H2	Hold for 10 minutes	7.5
1	Set blend to 15 vol% H2	Hold for 10 minutes	10
1	Step down to 10 vol% H2	Hold for 10 minutes	10
1	Step down to 5 vol% H2	Hold for 10 minutes	10
1	Step down to 0 vol% H2	Hold for 10 minutes	10
1	Step up to 5 vol% H2	Hold for 10 minutes	10
1	Step up to 10 vol% H2	Hold for 10 minutes	10
1	Step up to 15 vol% H2	Hold for 10 minutes	10
1	Initiate ramp of CTG to Baseload	Continue at 15 vol% H2 blending while ramping CTG for 3 mins	0
1	Hold H2 at 15 vol%	Hold 3 mins while continuing CTG Ramp	3
1	Step down to 10 vol% H2 - While Ramping	Change H2 set point to 10 vol% - hold 3 mins while CTG Ramps	3
1	Step down to 5 vol% H2 - While Ramping	Change H2 set point to 5 vol% - hold 3 mins while continuing CTG Ramp	3
1	Step down to 0 vol% H2 - While Ramping	Change H2 set point to 0 vol% - hold 3 mins while continuing CTG Ramp	3
1	Step up to 5 vol% H2 - While Ramping	Change H2 set point to 5 vol% - hold 3 mins while continuing CTG Ramp	3

Test	Task	Description	Approx. Time of Step (mins)
1	Step up to 10 vol% H2 - While Ramping	Change H2 set point to 10 vol% - hold 3 mins while continuing CTG Ramp	3
1	Step up to 15 vol% H2 - While Ramping	Change H2 set point to 15 vol% - hold 3 mins while continuing CTG Ramp	3
1	Hold @ Baseload & 15 vol% H2	Hold for 5 minutes	5
1	Trip H2 Supply Valve	End Test	-
1	Test 2 End	CTG left at Baseload (or per requirement of OPS)	-

Approximate time step of activities on IESO Test 2 Day 1

Test	Task	Description	Approx. Time of Step (mins)
2	CTG @ Baseload	Set at base load on CTG ~200MW	-
2	Ramp H2 to 15 vol%		7.5
2	Initiate ramp to MLP (135MW)		0
2	Hold H2 at 15 vol%	Step up to 15 vol% H2 and hold for 4 minutes - Continue ramping down CTG.	4
2	Step down to 10 vol% H2	Step down to 10 vol% H2 and hold for 4 minutes - Continue ramping down CTG.	4
2	Step down to 5 vol% H2	Step down to 5 vol% H2 and hold for 4 minutes - Continue ramping down CTG.	4
2	Step down to 0 vol% H2	Step down to 0 vol% H2 and hold for 4 minutes - Continue ramping down CTG.	4
2	Restart Blend - Step up to 5 vol% H2	Set up to 5 vol% H2 and hold for 3 minutes.	3
2	Step down to 0 vol% H2	Set up to 0 vol% H2 and hold for 3 minutes.	3
2	Step up to 5 vol% H2	Set up to 5 vol% H2 while ramping to 10 vol%	1
2	Step up to 10 vol% H2	Set up to 10 vol% H2 and hold for 3 minutes.	3
2	Step up to 15 vol% H2	Set up to 15 vol% H2 and hold for 3 minutes.	3
2	Maintain hydrogen blend until depletion	End Test	15

Approximate time step of activities of IESO Test 2 Day 2

Test	Task	Description	Approx. Time of Step (mins)
2	Step up to 5 vol% H2	Change H2 set point to 5 vol% - Allow up to 2 minutes to ramp H2. Hold 10 mins with CTG @ Baseload and H2 at setpoint.	12
2	Step up to 10 vol% H2	Change H2 set point to 10 vol% - Allow up to 2 minutes to ramp H2. Hold 10 mins with CTG @ Baseload and H2 at setpoint.	12
2	Step up to 15 vol% H2	Change H2 set point to 15 vol% - Allow up to 2 minutes to ramp H2. Hold 10 mins with CTG @ Baseload and H2 at setpoint.	12
2	Step down to 10 vol% H2	Change H2 set point to 10 vol% - Allow up to 2 minutes to ramp H2. Hold 10 mins with CTG @ Baseload and H2 at setpoint.	12
2	Step down to 5 vol% H2	Change H2 set point to 5 vol% - Allow up to 2 minutes to ramp H2. Hold 10 mins with CTG @ Baseload and H2 at setpoint.	12
2	Step down to 0 vol% H2	Change H2 set point to 0 vol% - Allow up to 2 minutes to ramp H2. Hold 10 mins with CTG @ Baseload and H2 at setpoint.	12
2	Adjust CTG 1 & CTG 2 to Baseload (grid demand)	Ramp at 13MW/min	N/A
2	Ramp to 10 vol% H2 on both CTGs simultaneously	Ramp at 2.5 vol% H2/min	4
2	Hold at 10 vol% H2	Hold for 3 minutes	3
2	Ramp to 15 vol% H2 on both CTGs simultaneously	Ramp at 2.5 vol% H2/min	2
2	Hold at 15 vol% H2 until depletion	End Test	N/A

Approximate time step of activities on IESO Test 3 Day 1

Test	Task	Description	Approx. Time of Step (mins)
3	Start	Set CTG to Baseload (~200MW)	
3	CTG @ MLP load - H2 at 0 vol% for time = 0	CTG @ 160MW	-
3	Ramp H2 to 5 vol%	2 vol%/min increase of Hydrogen	2.5
3	Ramp CTG by 25MW	Hold H2 constant	5
3	Hold CTG @ 185MW & H2 @ 5 vol%	Hold for 5 mins	5
3	Trip H2 Supply Valve	End test 1A	0
3	CTG @ MLP load - H2 at 0 vol% for time = 0	H2 @ 0 vol%	0
3	Ramp H2 to 10 vol%	Ramp at 2 vol%/min	5
3	Ramp CTG by 25 MW	Hold H2 constant	5
3	Hold CTG @ 185MW & H2 @ 10 vol%	Hold for 5 mins	5
3	Trip H2 Supply Valve	End test 1B	3
3	CTG @ MLP load - H2 at 0 vol% for time = 0	H2 @ 0 vol%	-
3	Ramp H2 to 15 vol%	Ramp at 2 vol%/min	7.5
3	Ramp CTG by 25 MW	Hold H2 constant	5
3	Hold CTG @ 185MW & H2 @ 15 vol%	Hold for 5 mins	5
3	Trip H2 Supply Valve	End test 1C	0

Appendix 2 – Commissioning Operator Setpoints & Results

The following section outlines the activities completed during the commissioning days. For each day, a comprehensive table summarizes the minute-by-minute activities, including parameters such as minimum loading point, run-time, and ramp rates. Accompanying each table is a corresponding graph illustrating changes in megawatt output (MW) and hydrogen volumetric percentage (vol%) over time. Together, these tables and figures provide a visual and quantitative record of the operational setpoints during the hydrogen blending commissioning.

Commissioning Results

It should be noted that the commissioning graphs display increased noise, as they represent the initial recordings taken during hydrogen introduction and Siemens Energy specialists adjusted the turbine's automated response during this phase. The observed fluctuations reflect deliberate testing by Siemens Energy, who intentionally stressed the system to ensure robustness for commercial operation.

Commissioning Operator Setpoints

Day 1 - July 2nd, 2025

Item	Task	Description	Approx. Duration of Step (mins)
1	Test Start - CTG @ Baseload	Set CTG to Baseload (~210MW)	0
2	Baseline Test - H2 at 0 vol%	No H2 blending, baseline for 1 hour	60
3	Ramp up to 5 vol% H2	Ramp 1 vol%/min for 5 minutes	5
4	Steady state test at 5 vol% H2	Hold for 20 minutes	20
5	Ramp up to 10 vol% H2	Ramp 1 vol%/min for 5 minutes	5
6	Steady state test at 10 vol%	Hold for 25 minutes for tuning	25
7	Ramp up to 15 vol% H2	Ramp 1 vol%/min for 5 minutes	5
8	Steady state test at 15 vol%	Hold for 45 minutes	45
9	Ramp down to 0 vol% H2	Ramp 1 vol%/min for 15 minutes	15
10	Hold at 0 vol% H2	Hold for 10 minutes	10
11	Ramp up to 5 vol% H2	Ramp 1 vol%/min for 5 minutes	5
12	Hold at 5 vol% H2	Hold for 1 minute	1

13	Ramp to 10 vol% H2	Ramp 1 vol%/min for 5 minutes	5
14	Ramp down to 5 vol% H2	Ramp 1 vol%/min for 5 minutes	5
15	CTG @ Baseload – 5 vol% H2	Hold for 10 minutes	10
16	Close H2 flow control valve	Test End	0.1

Item	Task	Description	Approx. Duration of Step (mins)
1	Test Start - CTG @ Baseload	Set CTG to Baseload (~210MW)	0
2	Ramp up to 5 vol% H2	Ramp 1 vol%/min for 5 minutes	5
3	Steady state test at 5 vol% H2	Hold for 10 minutes	10
4	Ramp up to 10 vol% H2	Ramp 1 vol%/min for 5 minutes	5
5	Steady state test at 10 vol%	Hold for 10 minutes	10
6	Ramp up to 15 vol% H2	Ramp 1 vol%/min for 5 minutes	5
7	Steady state test at 15 vol%	Hold for 10 minutes	10
8	Ramp down to 10 vol% H2	Ramp 1 vol%/min for 5 minutes	5
9	Steady state test at 10 vol%	Hold for 5 minutes	5
10	CTG Ramp to Minimum Load	Maintain 10 vol% H2 - CTG ~135MW	10
11	Tuning at MLP - H2 at 10 vol%	Maintain 10 vol% H2 while tuning at MLP	15
12	Ramp to H2 at 15 vol%	Ramp 1 vol%/min for 5 minutes	5
13	Tuning at MLP - H2 at 15 vol%	Hold for 10 minutes while tuning at MLP	10
14	CTG Ramp to Baseload	Maintain 15 vol% H2 - CTG ~210MW	15
15	Hold at Baseload at 15 vol%	Hold for 5 minutes	5
16	Ramp down to 10 vol% H2	Ramp down 1 vol%/min for 5 minutes	5
17	CTG @ Baseload - 10 vol% H2	Hold for 10 minutes	10
18	Close H2 flow control valve	Test End	0.1

Item	Task	Description	Approx. Duration of Step (mins)
1	Test Start - CTG @ Baseload	Set CTG to Baseload (~210MW)	0
2	Ramp up to 5 vol% H2	Ramp 1 vol%/min for 5 minutes	5
3	Steady state test at 5 vol% H2	Hold for 20 minutes	20
4	Ramp up to 10 vol% H2	Ramp 1 vol%/min for 5 minutes	5
5	Steady state test at 10 vol%	Hold for 10 minutes	10
6	Ramp up to 15 vol% H2	Ramp 1 vol%/min for 5 minutes	5
7	Steady state test at 15 vol% H2	Hold for 15 minutes	15
8	Ramp CTG down to MLP while ramping down to 5 vol% H2	Ramp at 5MW/min and Ramp down 1 vol%/min for 10 minutes	10
9	Ramp CTG down to MLP and ramp up to 15 vol%	Ramp at 5MW/min and ramp up 1 vol%/min for 5 minutes	5
10	Ramp CTG up to Baseload and ramp up to 15 vol%	Ramp at 5MW/min and ramp up 1 vol%/min for 5 minutes	5
11	Ramp CTG up to Baseload and ramp down to 10 vol%	Ramp at 5MW/min and ramp down 1 vol%/min for 5 minutes	5
12	Ramp CTG up to Baseload and hold at 10 vol% H2	Ramp at 5MW/min	5
13	Close H2 flow control valve	Manual trip of H2 control valve via T3K	0.1
14	Baseload on CTG, No H2	Hold for 5 mins	5
15	Ramp up to 15 vol% H2	Ramp 1 vol%/min for 15 minutes	15
16	CTG @ Baseload - 15 vol% H2	Hold for 5 minutes	5
17	Close H2 flow control valve	Manual trip of H2 control valve via T3K	0.1
18	Baseload on CTG, No H2	Hold for 15 minutes	15
19	Ramp up to 10 vol% H2	Ramp 1 vol%/min for 10 minutes	10
20	Ramp CTG down to MLP @ fast ramp rate at 10 vol% H2	CTG ramp rate set to 13MW/min	5

Item	Task	Description	Approx. Duration of Step (mins)
21	Ramp up to 15 vol% H2	Ramp 1 vol%/min for 5 minutes white CTG at MLP	5
22	Ramp CTG up to Baseload @ fast ramp rate	CTG ramp rate set to 13MW/min	5
23	Hold at Baseload and 15 vol% H2	Depletion test	40
24	Close H2 flow control valve	Test End	0

Item	Task	Description	Approx. Duration of Step (mins)
1	Test Start - CTG @ Baseload	CTG at Baseload (~200MW)	0
2	Baseline Test - H2 at 0 vol%	No H2 blending, baseline for 1 hour	60
3	Ramp up to 5 vol% H2	Ramp 2 vol%/min for 2.5 minutes	2.5
4	Hold at 5 vol% H2	Hold for 10 minutes	10
5	Ramp up to 10 vol% H2	Ramp 2 vol%/min for 2.5 minutes	2.5
6	Hold at 10 vol% H2	Hold for 20 minutes for tuning	20
7	Ramp up to 15 vol% H2	Ramp 2 vol%/min for 2.5 minutes	2.5
8	Hold at 15 vol% H2	Hold for 25 minutes for tuning	25
9	Tuning at steady state 15 vol% (burner)	Hold for 15 minutes	15
10	Ramp down to 5 vol% H2	Ramp 2 vol%/min for 5 minutes	5
11	Hold at 5 vol% H2	Hold for 5 minutes	5
12	Ramp CTG down to MLP	Ramp at 5MW/min	15
13	Hold at MLP and 5 vol% H2	Hold for 10 minutes	10
14	Ramp up to 10 vol% H2	Ramp 2 vol%/min for 2.5 minutes	2.5
15	Hold at 10 vol%	Hold for 10 minutes for tuning	10
16	Ramp up to 15 vol% H2	Ramp 2 vol%/min for 2.5 minutes	2.5
17	Hold at 15 vol% H2	Hold for 10 minutes for tuning	10
18	Ramp down to 10 vol% H2	Ramp 2 vol%/min for 2.5 minutes	2.5
19	Hold at 10 vol% H2	Hold for 2 mins	2
20	Ramp CTG up to Baseload	Ramp at 5MW/min while maintaining 10 vol% H2	15
21	Ramp up to 15 vol% H2	Ramp 2 vol%/min for 2.5 minutes	2.5

Item	Task	Description	Approx. Duration of Step (mins)
22	Hold at 15 vol% H ₂	Hold for 10 minutes	10
23	Ramp down to 10 vol% H ₂	Ramp 2 vol%/min for 2.5 minutes	2.5
24	Close H ₂ flow control valve	Test End	0.1

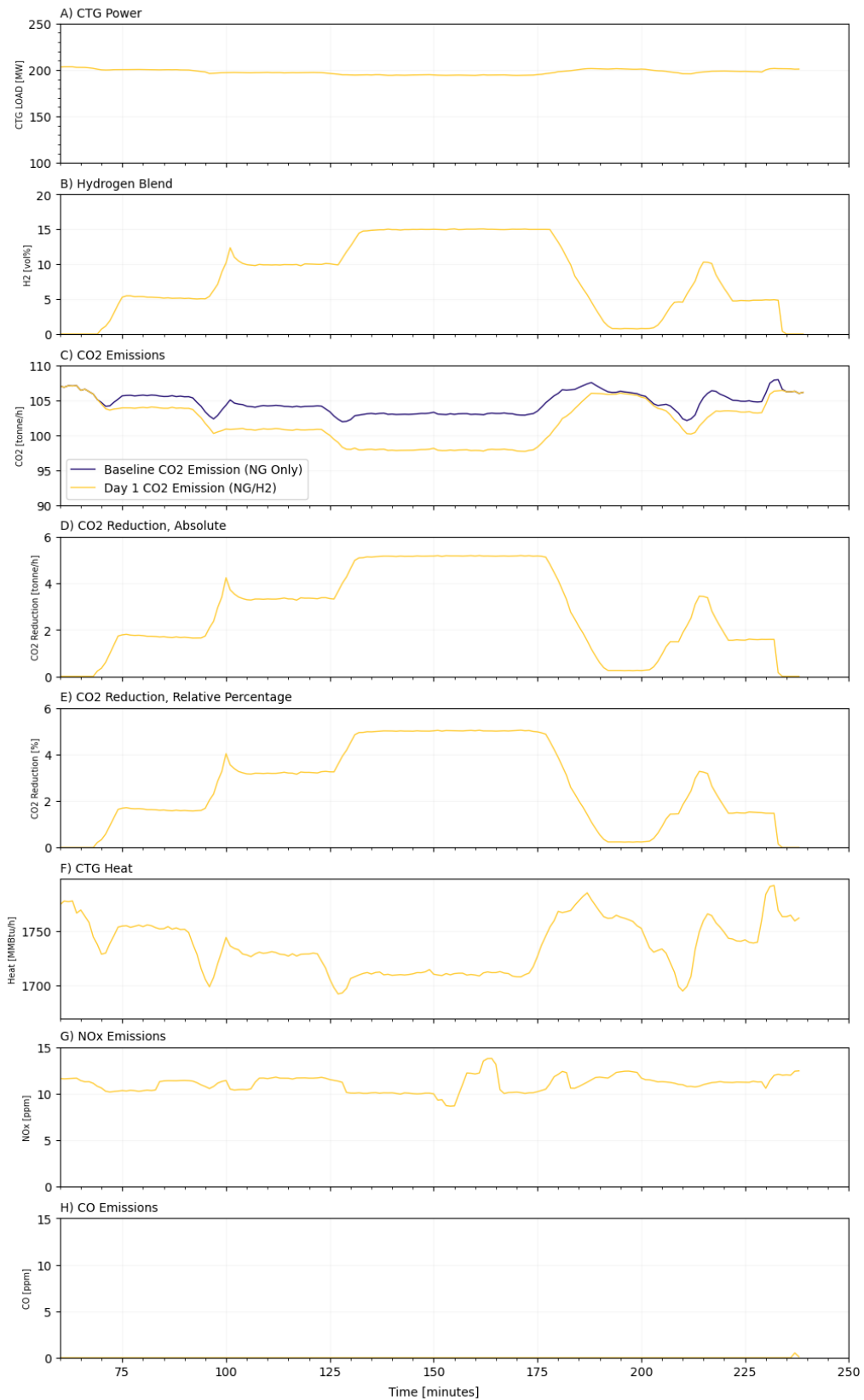
Item	Task	Description	Approx. Duration of Step (mins)
1	Start	Set CTG to Baseload (~200MW)	
2	Baseline Test, no H2 (GT heat soak) (1)	Hold for 60 minutes	15
3	Ramp up H2 to 15 vol%	Ramp for 10 minutes at 2 vol%/min H2	10
4	Hold at baseline Test at constant 15 vol% H2	Hold for 10 mins	10
5	Load ramp to MLP (5MW/min) Test at constant 15 vol% H2	Ramp down for 12 minutes	12
6	Test at steady state 15 vol% and MLP	Hold for 10 minutes	10
7	Load Ramp to Baseload (5MW/min) Test at constant 15 vol% H2	Ramp up for 12 minutes	13
8	Test at steady state 15 vol%	Hold for 15 minutes	15
9	Fast load ramp to min load (13.4MW/min) Test at constant 15 vol% H2	Ramp down for 5 minutes	5
10	Test at steady state 15 vol% and MLP	Hold for 10 minutes	10
11	Fast load ramp to base load (13.4MW/min) Test at constant 15 vol% H2	Ramp up for 5 minutes	5
12	Hold at steady state 15 vol% and Baseload	Hold for 10 minutes	10
13	Close H2 flow control valve	CTG2 stabilized within 3 minutes	10
14	Ramp up H2 to 15 vol%	Ramp for 7.5 minutes at 2 vol%/min H2	7.5

Item	Task	Description	Approx. Duration of Step (mins)
15	Hold at steady state 15 vol% and Baseload	Hold for 5 minutes	5
16	Close H2 flow control valve	CTG2 stabilized within 3 minutes	6
17	Ramp up H2 to 5 vol%	Ramp for 2.5 minutes at 2 vol%/min H2	2.5
18	Ramp down H2 to 5 vol% and load ramp to MLP (5MW/min)	Ramp for 2.5 minutes at 2 vol%/min H2	2.5
19	Hold H2 at 0 vol% while load ramping to MLP (5MW/min)	Hold for 10 minutes	10
20	Hold H2 at 0 vol% and MLP	Hold for 2 minutes	2
21	Ramp up H2 to 15 vol%	Ramp for 7.5 minutes at 2 vol%/min H2	7.5
22	Hold at steady state 15 vol% and MLP	Hold for 10 minutes	10
23	Close H2 flow control valve	CTG2 stabilized within 3 minutes	3
24	Ramp up H2 to 15 vol% while ramping to Baseload (5MW/min)	Ramp for 7.5 minutes at 2 vol%/min H2	7.5
25	Continue ramp to Baseload (5MW/min)	Ramp up for 5.5 minutes	5.5
26	Hold at constant 15 vol% H2 while maintaining Baseload	Hold for 12 mins	12
27	Close H2 flow control valve	CTG2 stabilized within 3 minutes	7.5

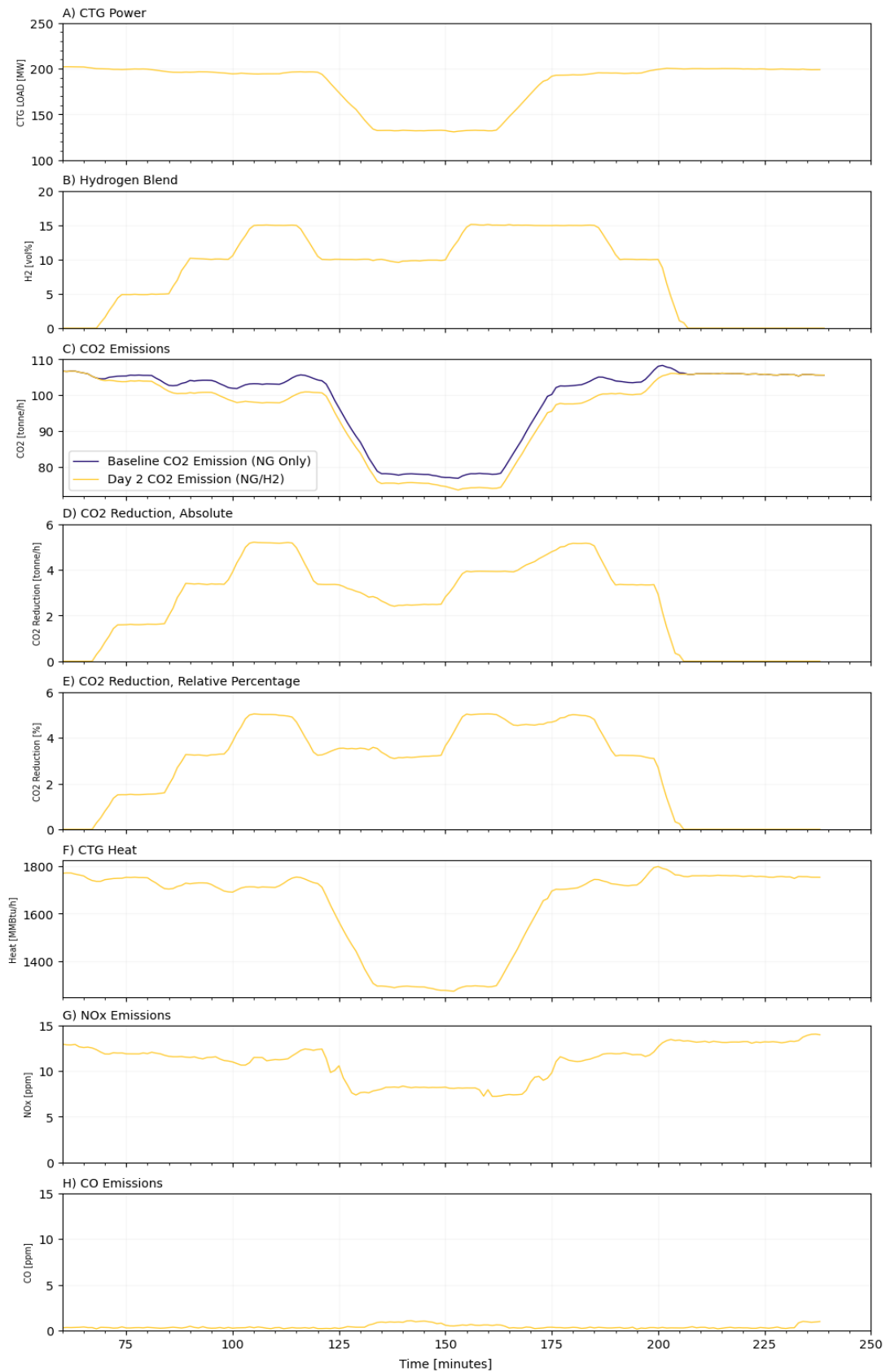
Item	Task	Description	Approx. Time of Step (mins)
1	Start	Set CTG to Baseload (~200MW)	
2	Baseline Test, no H2 (GT heat soak) (1)	Hold for heat soak only	15
3	Ramp up H2 to 5 vol%	Ramp 2 vol%/min for 2.5 minutes	2.5
4	Test at steady state 5 vol%	Hold for 5 minutes	5
5	Ramp up H2 to 10 vol%	Ramp 2 vol%/min for 2.5 minutes	2.5
6	Hold at steady state 10 vol%	Hold for 10 minutes for tuning	10
7	Ramp up H2 to 15 vol%	Ramp 2 vol%/min for 2.5 minutes	2.5
8	Hold at steady state 15 vol%	Hold for 20 minutes for tuning	20
9	Ramp down to 0 vol% H2 while load ramping to MLP (5MW/min)	Ramp 2 vol%/min for 2.5 minutes while load ramping to MLP (5MW/min)	7.5
10	Hold at 0 vol% while load ramping to MLP (5MW/min)	Hold at 0 vol% for 2.5 minutes while load ramping to MLP (5MW/min)	2.5
11	Hold at 0 vol% and MLP	Hold for 5 minutes	5
12	Ramp up H2 to 15 vol% while load ramping to Baseload (5MW/min)	Ramp 2 vol%/min for 7.5 minutes	7.5
13	Ramp down H2 to 0 vol% while load ramping to Baseload (5MW/min)	Ramp 2 vol%/min for 7.5 minutes	7.5
14	Hold at 0 vol% and Baseload	Hold for 2 minutes	2
15	Ramp up H2 to 15 vol%	Ramp 2 vol%/min for 7.5 minutes	7.5
16	Hold at steady state 15 vol%	Hold for 7.5 minutes for tuning	7.5

Item	Task	Description	Approx. Time of Step (mins)
17	Ramp down H2 to 0 vol% and Fast load ramp to MLP (13.4MW/min)	Ramp 2 vol%/min for 7.5 minutes and Fast ramp rate on GT (13MW/min) for 5 minutes and hold at MLP for 2.5 minutes	7.5
18	Hold at 0 vol% and MLP	Hold for 5 minutes	5
19	Fast load ramp to Baseload (13.4MW/min) and ramp up H2 to 15 vol%	Fast ramp rate on GT (13MW/min) for 5 minutes and hold at Baseload for 3 minutes while ramping 2 vol%/min for 7.5 minutes	7.5
20	Steady state test at 15 vol% and Baseload	Hold for 30 minutes	30
21	Ramp down H2 to 10 vol%	Ramp 2 vol%/min for 2.5 minutes	2.5
22	Steady state test at 10 vol% and Baseload	Hold for 45 minutes	45
23	Close H2 flow control valve	CTG2 stabilized within 3 minutes	3
24	Continue monitoring at 0 vol%	Continue monitoring for 60 minutes	60

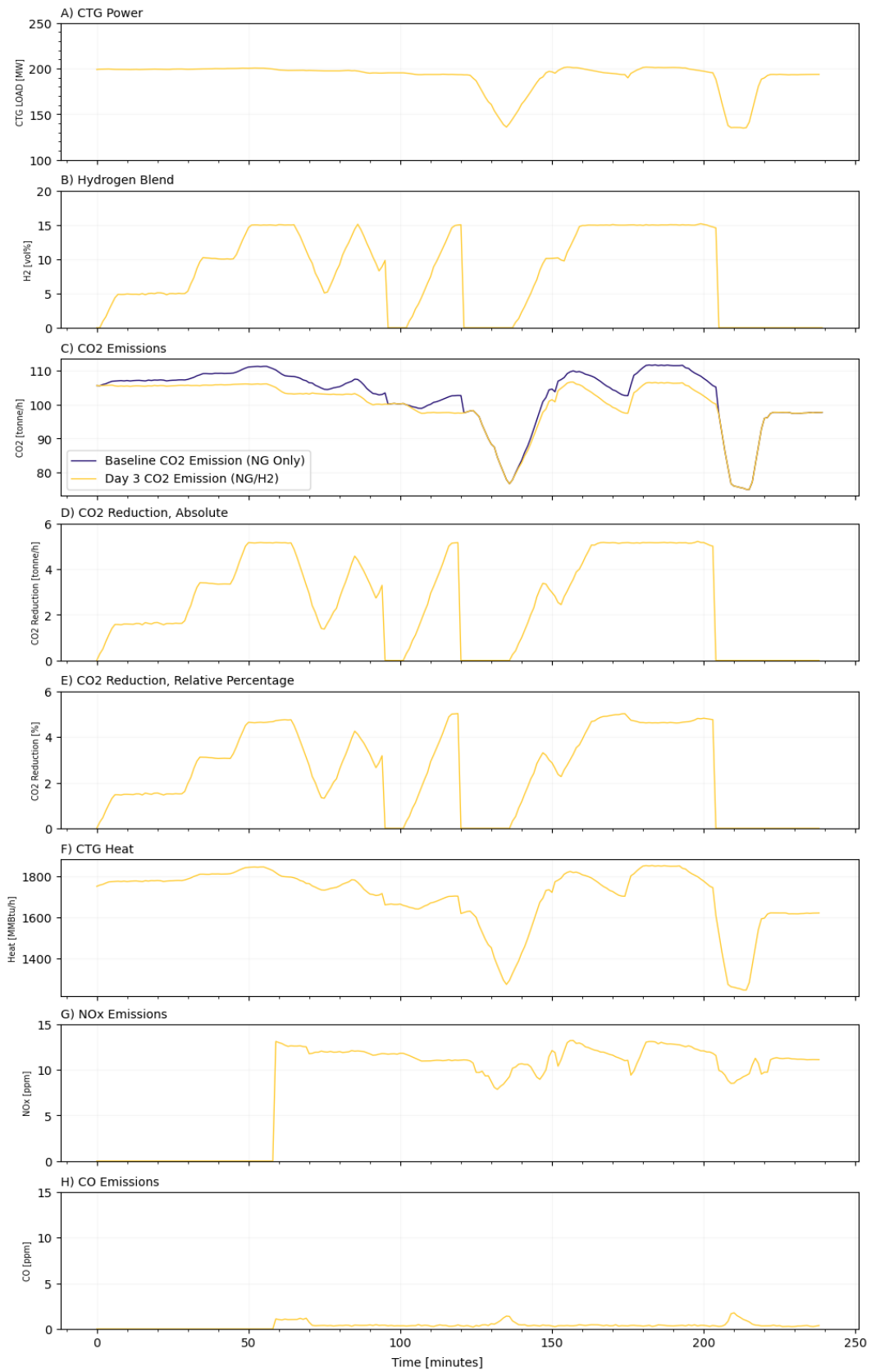
Day 1 - July 2nd, 2025

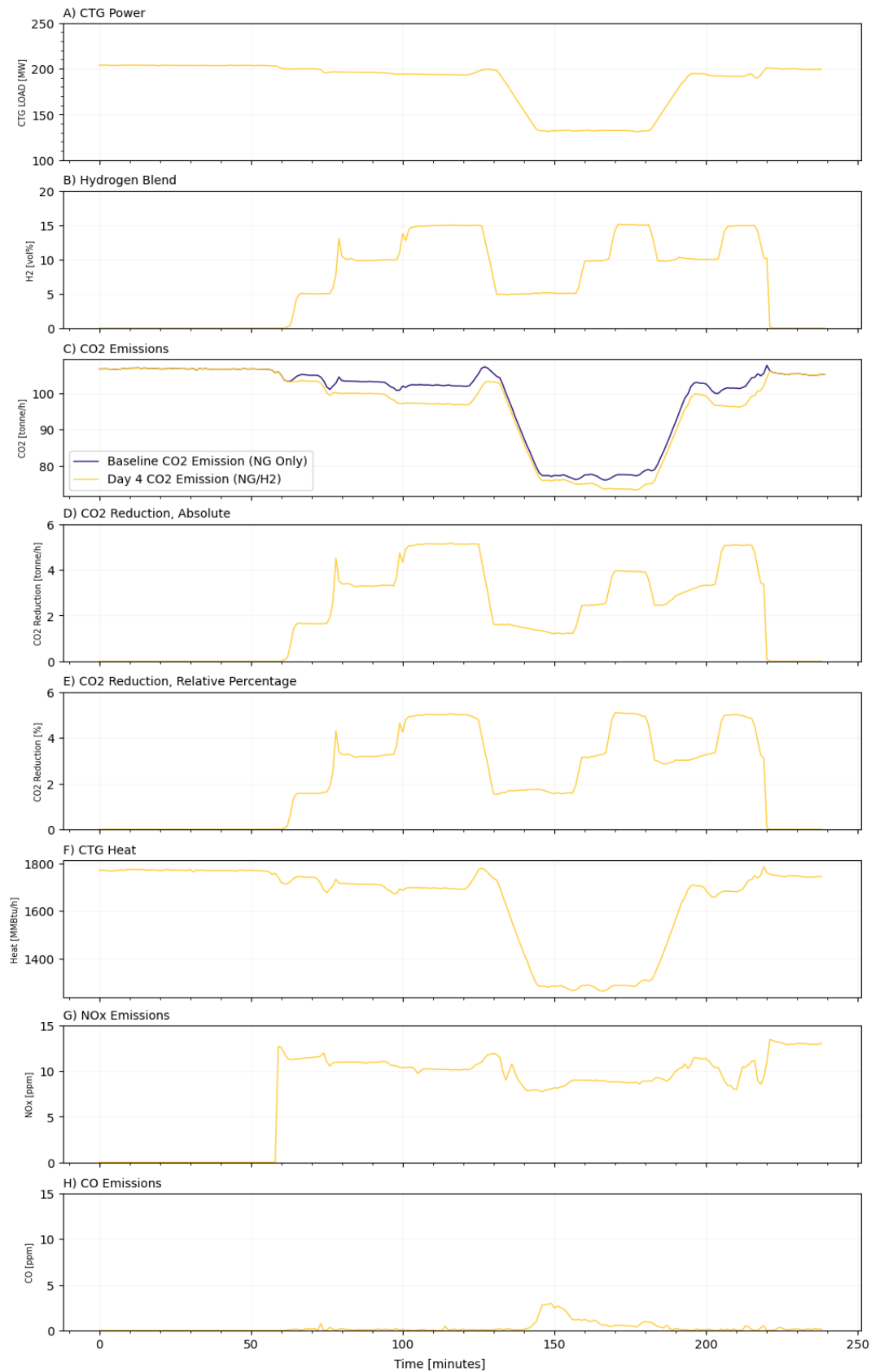


Day 2 - July 4th, 2025

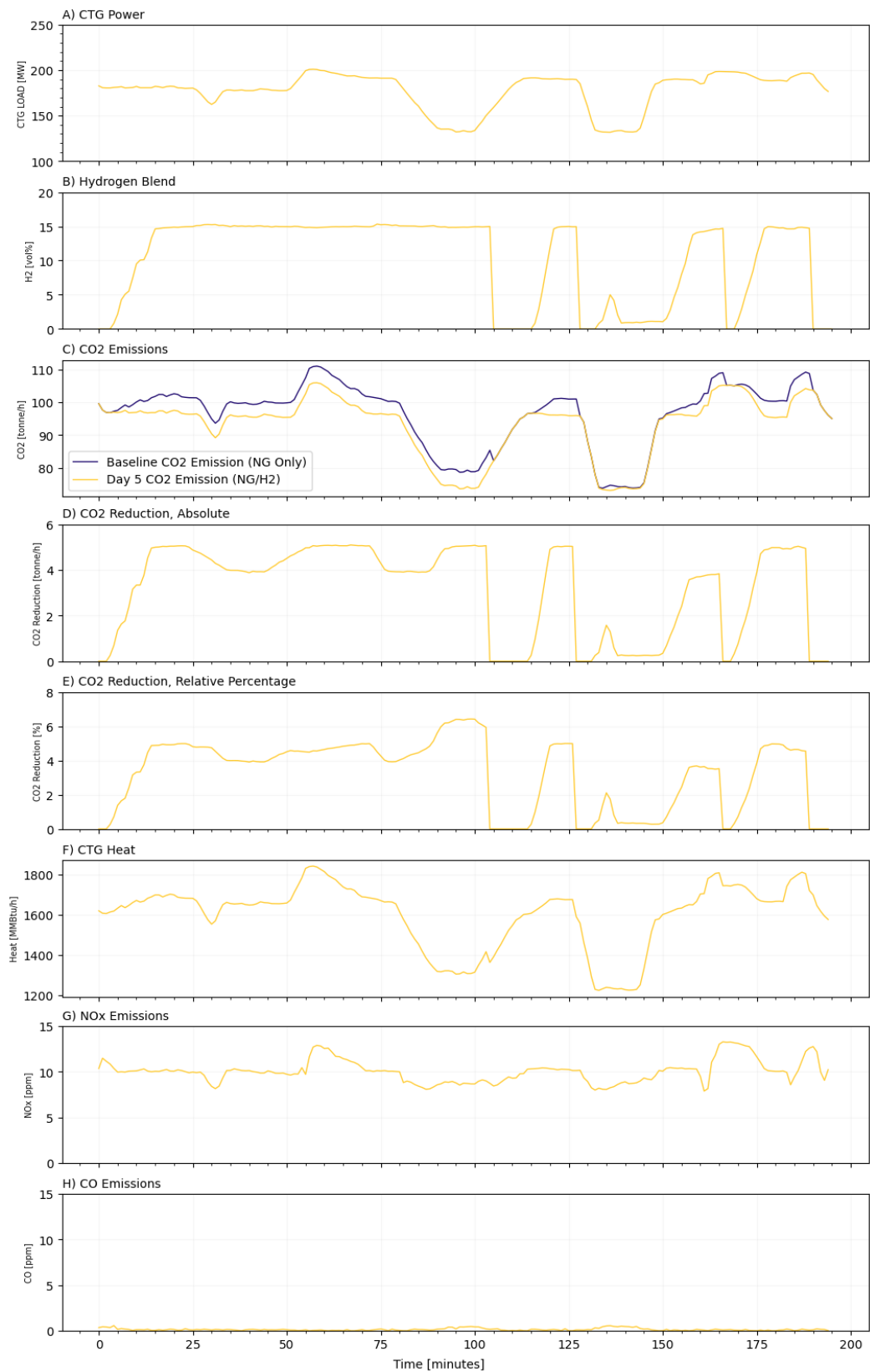


Day 3 - July 7th, 2025

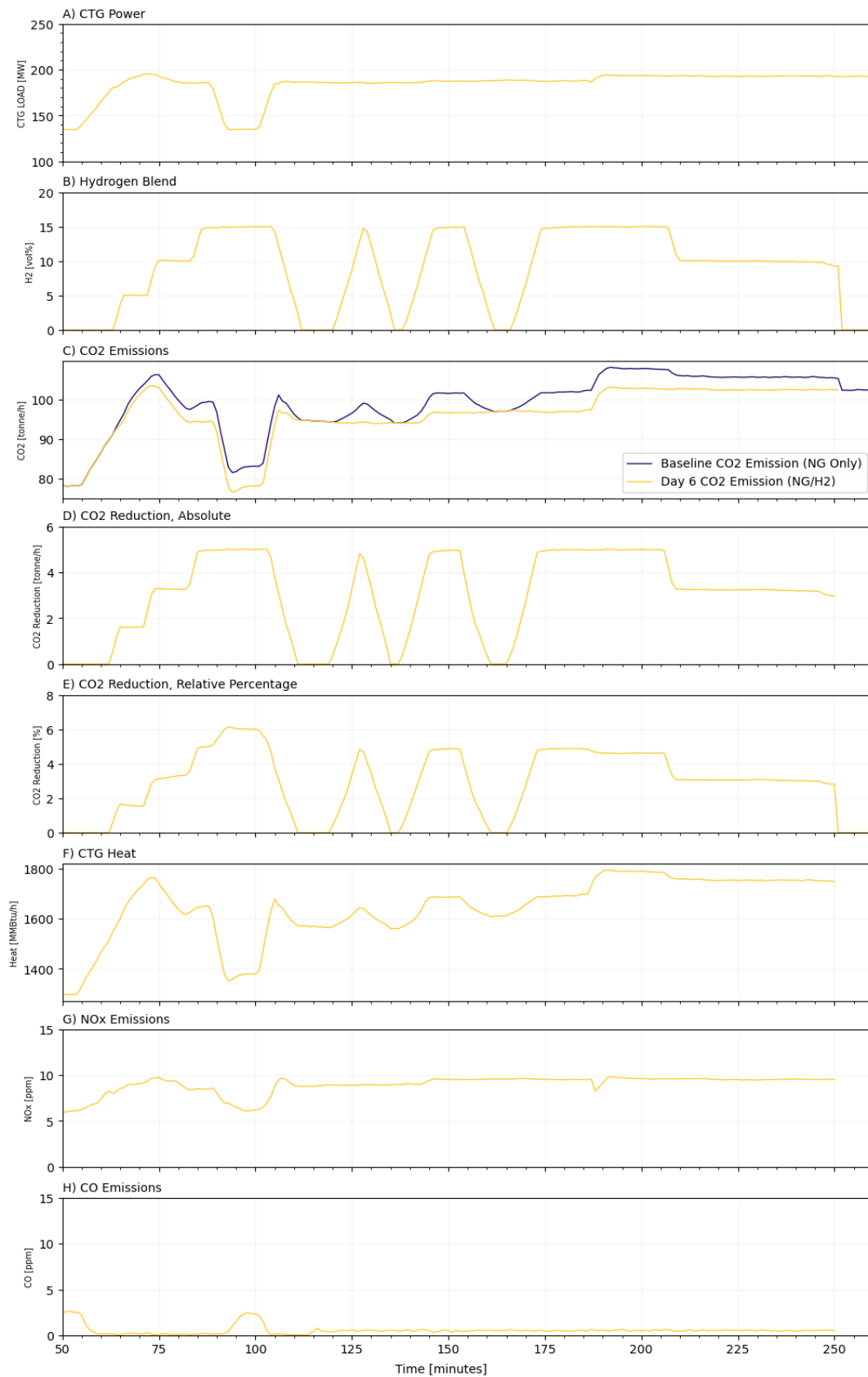




Day 5 - July 13th, 2025



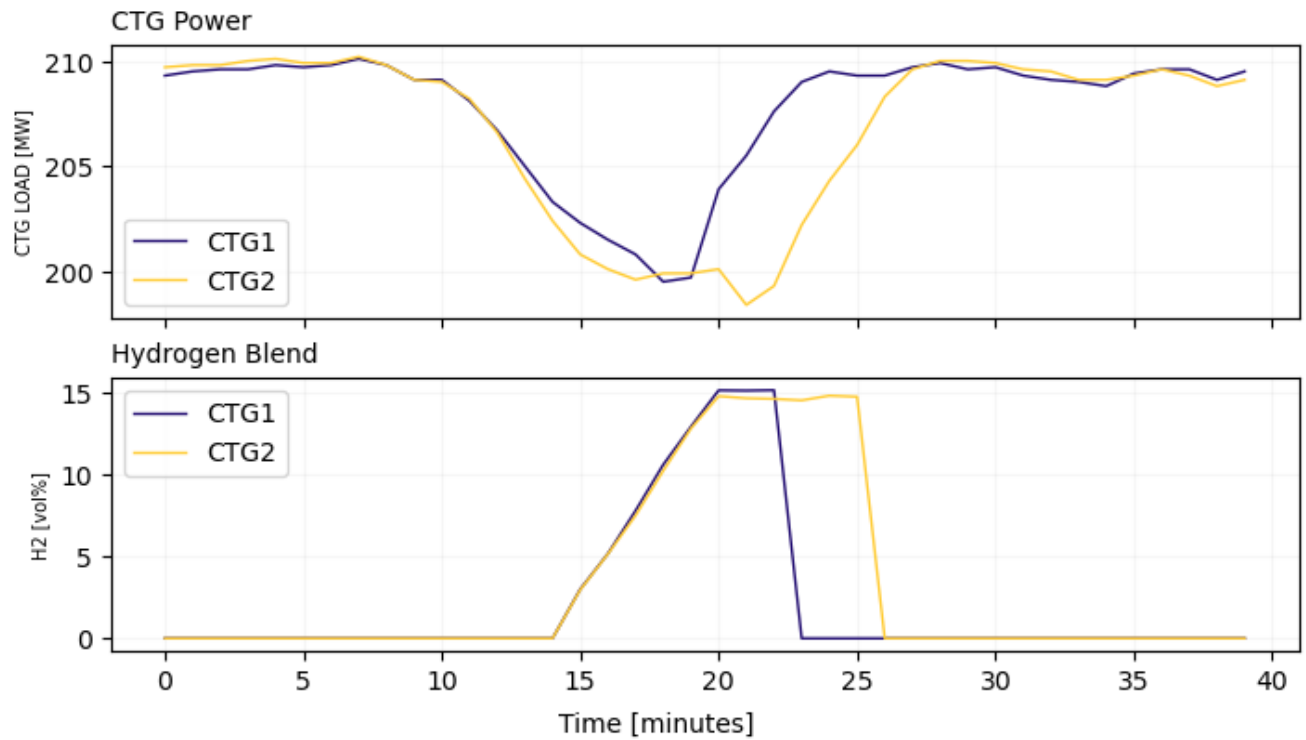
Day 6 - July 16th, 2025



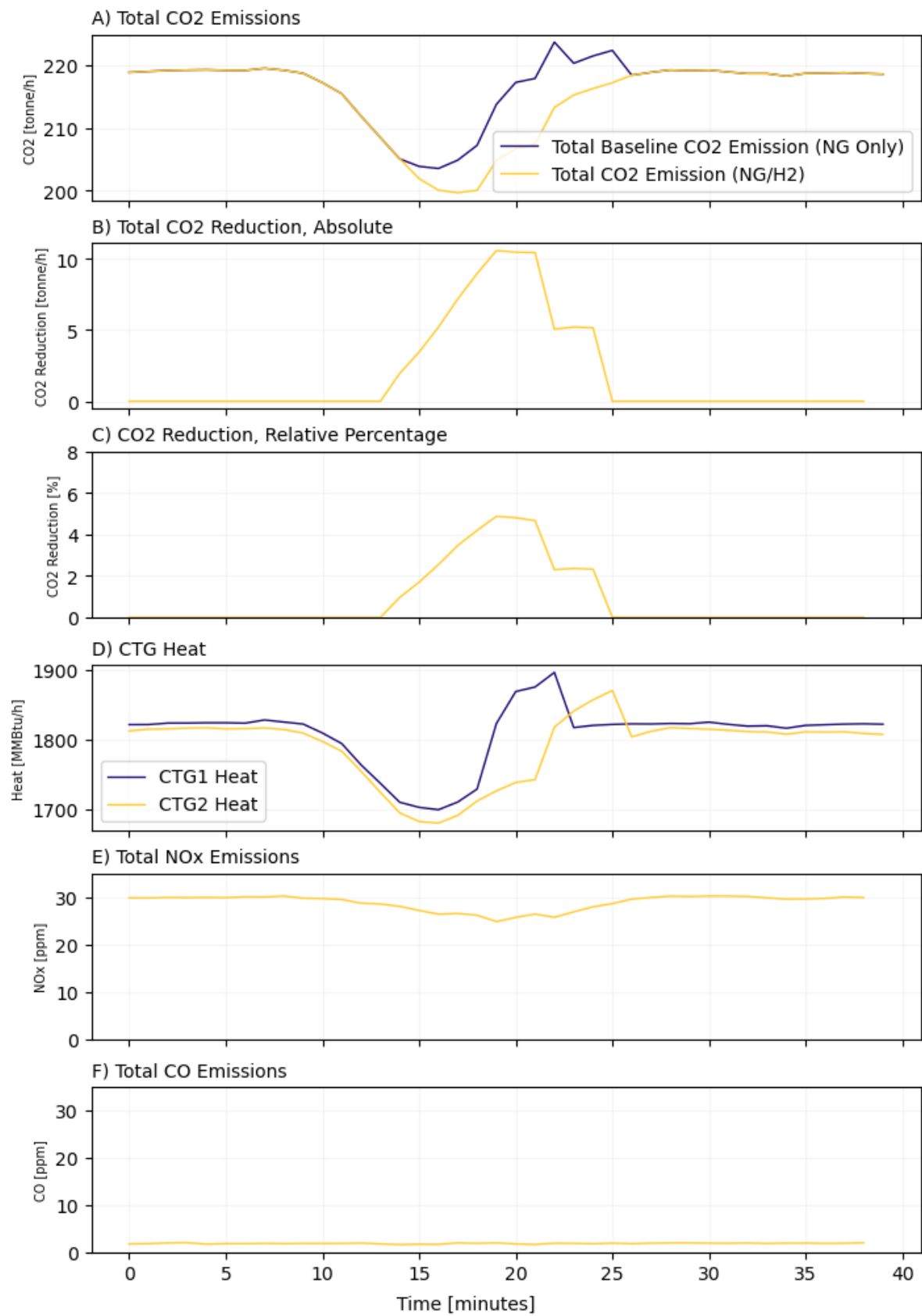
Two CTG Operation

After testing was completed, the remaining hydrogen was used for dual CTG operation. The combined power output and hydrogen blend to each CTG is presented in the graphic below with the results from this trial.

Operator Setpoints



Results



Appendix 3 – Test Setup Photos

The following image shows the hydrogen tube trailers, the pressure-reducing skids, and the temporary piping that runs along the HRSG building.



This image shows the HRSG building, where the hydrogen piping runs along the exterior wall before reaching the two hydrogen blending skids located at each respective CTG.



This photograph demonstrates one of the hydrogen blending skids used for regulating the hydrogen vol % blend prior to being introduced into the natural gas for combustion.



