Hydrogen Blending – Goreway Power Station, East Windsor Cogeneration Centre, and York Energy Centre

Capital Power Corporation

2024-06-30

This project was supported by the financial contribution of the Independent Electricity System Operator.

This project is supported by the financial contribution of the Independent Electricity System Operator (IESO), through its Hydrogen Innovation Fund. However, the views, opinions and learnings expressed in this report are solely those of the Capital Power Corporation.

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1. Executive Summary

Hydrogen Sourcing, Storage, and Transportation

Capital Power engaged with Black & Veatch to conduct a feasibility study on the delivery, storage, and utilization of a blended fuel source. The feasibility study determined that:

- Gaseous hydrogen deliveries with onsite storage, are viable for near-term low-capacity factor blending operations.
- For high-capacity factor base-loaded operations, a more permanent hydrogen source, such as a hydrogen pipeline, will be required.
- No upgrades are expected downstream of the turbine exhaust, assuming the exhaust conditions are like current operations.

Goreway Power Station

Capital Power engaged with General Electric (OEM of all 3 gas turbine generators at the facility) to conduct a feasibility study of hydrogen blending at Goreway Power Station. The feasibility study determined that:

- The existing turbines can operate at the OEM specified hydrogen blending percentage.
- To accommodate hydrogen blending, a blending skid will be required for each of the turbines. The piping, purging systems, and hydrogen detection systems would require modifications. While the fire control system, combustion support systems, and the Heat Recovery Steam Generator (HRSG) would not need changes.

East Windsor Cogeneration Centre

Capital Power engaged with General Electric (OEM of both gas turbine generators at the facility) to conduct a feasibility study of hydrogen blending at East Windsor Cogeneration Centre. The feasibility study determined that:

- With minor changes to the turbines and the addition of a blending skid, each turbine can operate at the OEM specified hydrogen blending percentage.
- For higher levels of hydrogen blending, a major overhaul or turbine replacement would be required.
- Further studies are needed for locating the needed blending equipment and analysis of hazard zones.

York Energy Centre

Capital Power engaged with Siemens Energy (OEM of both turbines at the facility) to conduct a feasibility study of hydrogen blending at York Energy Centre. The study determined that:

- The turbines are capable of up to 10% hydrogen blending by volume without major retrofit.

- The turbines are capable of up to 30% blending but would require conversion of the fuel gas system to 316L stainless steel.
- No peak firing is available with a hydrogen blended fuel.

Conclusions

If hydrogen blending were to be pursued by Capital Power at any of the Ontario facilities, additional engineering design and further study is required to fully understand the technical, commercial, supply chain, environmental, and regulatory factors of a potential project.

2. Introduction and Goal

In recent years, a lot of attention has been given to hydrogen as a potential solution towards decarbonization of the power industry. Traditionally, hydrogen was used exclusively in oil and gas refinement. This hydrogen was usually produced via steam-methane reforming of natural gas and was a power intensive process. Due to this, hydrogen blending with steam-methane reformed hydrogen was not seen as a viable way to decarbonize gas facilities. However, with the advancements in commercial scale electrolysers, improvements in turbine technology, and the availability of renewable energy in the power grid, interest in hydrogen blending has resurfaced to reduce carbon emissions at existing gas turbine facilities.

The Ontario Independent Electricity System Operator ("IESO") selected Capital Power Corporation ("Capital Power") to participate in the Hydrogen Innovation Fund (HIF). The goal was to assess the technical viability of blending and co-firing hydrogen and natural gas at Capital Power's Goreway Power Station ("Goreway"), East Windsor Cogeneration Centre ("East Windsor"), and York Energy Centre ("York").

Capital Power engaged Black & Veatch to study the Balance-of-Plant (BOP) aspects of hydrogen blending. For the gas turbine generators, Capital Power engaged the Original Equipment Manufacturers (OEM) General Electric ("GE") for Goreway Power Station and East Windsor Cogeneration Centre, and Siemens Energy ("Siemens") for York Energy Centre, to conduct the study.

Challenges and Considerations with Hydrogen

Hydrogen poses several challenges that this study will look to overcome.

Safety is an important factor when designing hydrogen systems. Hydrogen has a flammability range between 4% - 75% by volume in air, compared to natural gas' 5% - 15%. Thus, storage must be in a well-ventilated space or outdoors, to allow escaped gas to dissipate in air quickly. When ignited, the flames are not visible, nor give off radiant heat and smoke. First responders, as part of an emergency response plan, must be made aware of the hydrogen and used specialized hydrogen and infrared imaging to detect leaks. Furthermore, a safety analysis would be required to ensure hydrogen storage and piping have the necessary setback distances and safety considerations.

Hydrogen in its diatomic state of H_2, dissociates into piping steel and causes the steel to become brittle and crack. This is known as hydrogen embrittlement and carbon steels are the most susceptible. Higher concentrations of hydrogen increase the rate of hydrogen embrittlement. At high temperatures of hydrogen blended fuel, hydrogen attack occurs in addition to embrittlement. Hydrogen attack is when the hydrogen atoms react with carbon in steel, forming methane and fissures in the steel. To reduce the effects of hydrogen embrittlement and attack, fuel gas and blending piping must be replaced with a low-carbon stainless steel, especially at higher concentrations hydrogen.

While hydrogen blending reduces CO_2 emissions, it also produces higher NO_x emissions due to the higher combustion temperature. Especially at higher hydrogen blending percentages. When blending, care must be taken to ensure that NO_x emissions do not exceed environmental permits and regulations. OEMs have been working on turbine designs and control schemes with higher blending percentages, while minimizing NO_x production and facility de-rating.

Hydrogen is more energy dense by mass than natural gas but is less dense by volume. Thus, an increased flow of blended fuel is required to achieve the same heat input as natural gas. Due to the difference in heat input, the relationship between the CO_2 emission reductions and the percentage of hydrogen blend by volume is non-linear.

Capital Power Facilities

Goreway Power Station is an 875 MW, the combined cycle facility located within the city of Brampton, Ontario. The combined cycle facility utilizes three gas turbines, connected to a steam turbine in a 3x1 configuration. The stack is equipped with Selective Catalytic Reduction (SCR) to lower NO_x emission coming from the facility. Goreway Power station operates the most during intermediate and peak demand but has the capability to run for longer periods of time.

East Windsor Cogeneration Centre is a 92 MW, simple cycle gas plant, located in the city of Windsor, Ontario. The two simple cycle gas turbines are dispatched by IESO when required to support peak generation demand.

York Energy Centre is a 456 MW facility located in Newmarket, Ontario. Jointly owned but operated by Capital Power. The two simple cycle gas turbines are dispatched by IESO when required to support peak generation demand.

Study Goals

Black & Veatch was tasked with investigating the feasibility of various methods of hydrogen delivery, storage, and their effects on the BOP equipment.

Each OEM studied their existing turbines at each facility. The goal of the study was to determine the amount of hydrogen blend that the existing turbines are capable of; and then determine the amount of hydrogen blend with commercially available upgrades and equipment.

The studies and reports have been attached to this report as follows:

- Appendix 1 – Goreway Power Station Report
- Appendix 2 – York Energy Centre Report

3. Jurisdictional Scan

Climate

All three facilities are in Southern Ontario. As such, they experience large seasonal changes in temperature and precipitation. These conditions require a flexible approach to ensure smooth operations throughout the year.

Hydrogen equipment, located outside of a building, must be able to operate in both hot and cold temperatures. Typical design requires equipment to be rated for temperatures between -40°C to 35°C.

Local Generation

Goreway Power Station is located near the major population centre of Toronto. Goreway Power Station shares the transmission infrastructure with three nearby combined cycle gas facilities, in which Goreway is the largest. To the east of the Toronto population centre, there are two nuclear plants.

East Windsor Cogeneration Centre is in the city of Windsor, a population centre and with a history of manufacturing and industry. Nearby are three larger gas facilities, two of which being combined cycle gas facilities. The closest renewable energy source is a solar facility located on the Windsor International Airport. A 230kV transmission line connects the city to several wind farms to the east.

York Energy Centre is in Newmarket, a town surrounded by farmland and fields. York Energy Centre is on a 230kV transmission line that connects a few hydroelectric dams to the Toronto area. The closest renewable energy source is a wind farm west of the facility.

Figure 1 | Goreway Power Station, East Windsor Cogeneration, and York Energy Centre in Relation to Other Generation Sources in the IESO (Source: IESO Ontario Energy Map)

4. Approach/Methodology and Assumptions

Assumptions

- There is no underground storage near the facilities. Hydrogen storage is assumed to be aboveground either in onsite tanks, or on the hydrogen trailers.
- There is currently no hydrogen pipeline infrastructure to supply the facilities. All hydrogen will be trucked in via hydrogen trailers.

Hydrogen Sourcing, Storage, and Transportation

Black & Veatch used the site information and generation data to determine the amount of hydrogen consumed, and reductions in CO_2 emissions for all three facilities. From that, Black & Veatch then studied the feasibility of aboveground storage, hydrogen deliveries, and effects on BOP equipment.

Goreway Power Station

GE performed an assessment on the gas turbine systems. GE then provided the results of their assessment in the upgrades required, equipment needed, impacts on instrumentation, and a high-level risk assessment.

At the time of the study, Goreway Power Station turbines were undergoing an upgrade, GE was instructed to model the turbines post-upgrade.

East Windsor Cogeneration Centre

Using the provided site information, GE generated the performance of the turbines; they modelled used turbines for the study, instead of new. The emissions were restricted to the current air permits.

York Energy Centre

Using the provided site information, Siemens Energy investigated the impact and feasibility of hydrogen co-firing on the auxiliary systems of the gas turbines. This included assessing the blending skid components, piping and the challenges posed by cold temperatures. Siemens Energy also estimated the number of hydrogen supply trucks required and developed a layout for offloading of hydrogen supply trucks. At the time of the study, York Energy Centre was undergoing an upgrade, Siemens Energy was instructed to model turbines post-upgrade.

The boundary conditions are explained in more detail in Appendix 2 – York Energy Centre Report - Section 3.

5. Results and Analysis

Hydrogen Sourcing, Storage and Transportation

Based on the operating hours, hourly generation, and heat rate information, Black & Veatch calculated the expected hydrogen consumption and resulting reduction in CO_2 emissions. East Windsor and York are used for peaking generation. While Goreway operates more often, it is not a fully base loaded facility.

With the calculated hydrogen consumption for each facility, Black & Veatch also sized an onsite electrolyser that would provide instantaneous hydrogen to the turbines.

Using their experience in the hydrogen market, Black & Veatch outlined the methods of hydrogen sourcing, and developed a traffic light matrix on each method's favourability.

Goreway Power Station

GE investigated three different hydrogen blending percentages and their effects on the turbine and existing SCR. From this investigation, GE determined an appropriate hydrogen blending percentage for their analysis of their systems.

For further details, see Appendix 1 – Goreway Power Station Report - Section 3.

East Windsor Cogeneration Centre

The performance data indicated that there were marginal changes in the performance of the turbines between the specified OEM hydrogen by volume blend, and no hydrogen blending.

York Energy Centre

Siemens Energy's study investigated that increasing hydrogen temperature increases the risk of hydrogen embrittlement and suggested upgrading fuel gas supply piping material to stainless steel to reduce the embrittlement risk. Siemens Energy assessed that the turbines could burn up to 30% hydrogen blended fuel while maintaining permitted emissions.

Siemens Energy's assessment indicated that the existing fuel gas system is sufficient for handling up to 30% hydrogen blending. However, for long-term operation, the piping and components would need to be upgraded. Siemens Energy also reviewed the applicability of their blending skid, equipped with sophisticated meters to accurately measure and control hydrogen flow. Calculations concluded the system could function in the local climate.

To ensure a sufficient supply of green hydrogen at the site, Siemens Energy estimated the need for 5-6 hydrogen trucks. Based on the general arrangement, Siemens Energy suggested supply trucks and pressure reduction station to be located on the south side of the plant to allow for safe traffic flow.

Detailed results and analysis are outlined in Appendix 2 – York Energy Centre Report - Section 4.

6. Discussion and Recommendations

Hydrogen Sourcing, Storage and Transportation

For most manufacturers, hydrogen blending will start once the turbine has reached steady state generation. Thus, operating hours are a big factor in the amount of carbon emissions avoided. Base loaded facilities with higher operating hours have larger reductions in carbon emissions from hydrogen blending, assuming the hydrogen used is from a carbon-free source.

Black & Veatch sized electrolysers that could provide hydrogen to the gas turbines. However, the efficiency loss, utilities required, and land needed made them less favourable than hydrogen deliveries.

Hydrogen deliveries make the most sense for short-term storage of hydrogen. Gaseous hydrogen deliveries do not need specialized equipment to unload, unlike liquid hydrogen deliveries, which require compressors and vaporizers. However, the lower density of the gaseous hydrogen does require more storage. Aboveground storage tanks would be required and need to be located according to hydrogen storage safety standards. Alternatively, the trailers themselves can be rented to act as aboveground storage. With both methods, space and land must be allocated to ensure the loading/offloading of the hydrogen and must account for the safety setbacks required for hydrogen.

A dedicated pipeline would be most cost-effective, long-term, and lowest carbon intensity solution for hydrogen delivery. However, there is a large capital cost and a need for upstream hydrogen infrastructure. A pre-blended fuel from a gas supplier may be an option to utilize existing natural gas infrastructure.

Goreway Power Station

Hydrogen piping systems need to be designed according to applicable hydrogen standards. Additional components, such as valves, seals, hydrogen leakage detection system, purge system, and sensors will also need to be modified for hydrogen. Hydrogen detection systems will require changes based on the hydrogen percentage.

Each unit will require a GE blending skid, which would be controlled from the GE control system. For the levels of hydrogen being considered, combustion support systems, and fire systems will not be required; higher concentrations would require additional modifications.

Based on preliminary investigation, no changes are anticipated on the HRSG.

The existing instrumentation within the hazardous operation area would not need to be changed. However, at higher percentages, instrumentation changes would be required.

For further details, see Appendix 1 – Goreway Power Station Report - Section 3.

East Windsor Cogeneration Centre

At this hydrogen by volume, no changes would need to be made to the existing turbines.

To facilitate the hydrogen blending, a GE provided blending skid would be required to monitor and control the blending concentrations in the fuel gas. This blending skid is designed to hydrogen safety standards. Stainless steel piping will be required from the blending skid to the hydrogen storage or delivery location, as it will be exposed to high concentrations of hydrogen.

York Energy Centre

To safely handle hydrogen-blended natural gas and avoid the risk hydrogen embrittlement at higher temperatures, Siemens Energy recommended to install thermal systems which will be exposed to hot hydrogen-blended gas designed as per ASTM 316L. For long-term operations, the fuel gas piping needs to be upgraded to 316L stainless steel. Siemens Energy reviewed the gas turbine auxiliary instrumentation and noted that no significant changes are expected as most of the instrumentation was found to be compatible hazard class standards.

Siemens Energy recommended to blend hydrogen only while operating between MECL and base load to minimize the effects of hydrogen on the start quality and start-up emissions. Siemens Energy recommend an optimal hydrogen usage percentage between 5% and 10% when considering heat rate impact on efficiency. Siemens Energy suggested each gas turbine to have their own blending to allow for individual start and H_2 blending. The blending skid from Siemens Energy meets hazardous location and electrical rating standards.

Siemens Energy recommended to seal the acoustic wall between the blending skid and the exhaust ductwork of the gas turbine to prevent potential leaking. Siemens Energy also suggested any instrumentation in a radius around the blending skid to be rated according to safety standards.

Siemens Energy recommended checking available truck capacities with hydrogen suppliers, depending on the blending percentage and operating hours.

For further details see Appendix 2 – York Energy Centre Report - Section 4.

7. Conclusions

Hydrogen Sourcing Storage and Transportation

Following the feasibility study, Black & Veatch concluded the following.

- Hydrogen blending with a carbon-free source would lead to a reduction in CO_2 emissions. This reduction in carbon will increase with higher hydrogen blending percentages.
- Hydrogen deliveries are viable for near-term, low-capacity factor facilities. High-capacity facilities, such as those used for base loaded operations, will require a pipeline for long-term hydrogen blending. This pipeline can be a dedicated hydrogen pipeline or pre-blended fuel.
- Capital requirements make pipeline delivery and on-site electrolysis unfavourable for near term operations.
- Changes to the fuel gas piping system to stainless steel will be required above 5% hydrogen blending. Changes downstream of the turbine exhaust are not expected.

If hydrogen blending were to be pursued, Black & Veatch recommended conducting engineering design, assessing hydrogen delivery sources, and keeping updated on changes/developments in hydrogen project incentives and legislations.

Goreway Power Station

The turbines can operate at the OEM specified hydrogen blending percentage. Each turbine would require a blending skid to facilitate the fuel blending. For this concentration of hydrogen, the piping, purging systems, and hydrogen detection systems would require modifications. The existing fire control system, combustion support systems, and the heat recovery steam generator, are sufficient and do not need modifications.

If Goreway Power Station were to pursue hydrogen blending, it would be recommended to conduct detailed engineering, assess safety and hazard mapping, investigate the SCR capabilities, and assess hydrogen supply.

East Windsor Cogeneration Centre

Minimal changes and additions are needed to facilitate the OEM specified hydrogen blend by volume. The largest addition would be a blending skid and stainless steel piping for facilitate the hydrogen blending.

There are minimal changes in the performance of the gas turbines.

York Energy Centre

Hydrogen cofiring is technically viable at York Energy Centre which would require, among other things, infrastructure modifications, including burner upgrades, blending systems, and safety enhancements.

Coordination with local hydrogen suppliers for sufficient supply at the site is crucial, and further detailed planning is required for subsequent project phases to optimize logistics and compliance with safety standards.

If Capital Power were to pursue hydrogen blending at York Energy Centre, further investigation would be needed. This would include exploring commercial viability and regulatory considerations, assessing safety standards, consulting with hydrogen suppliers, and investigating upgrade costs.

8. Lessons Learned

Several lessons have been learned from these studies.

1. The source of hydrogen production affects the carbon reduction. The carbon intensity of hydrogen produced via steam-methane reforming varies based on how the carbon emissions during production are handled. Utilizing hydrogen with a high carbon intensity for blending may result in net carbon emissions greater than using 100% natural gas/methane. Thus, carbon intensity of procured hydrogen must be considered to ensure that blending does not net in more carbon emissions.
2. Above ground storage is possible, either with permanently installed tanks or parked hydrogen trailers. This is more suitable for lower percentages of hydrogen blending and/or lower operating hours, reducing the need for constant hydrogen deliveries. Pipeline infrastructure is the most cost-effective method of hydrogen delivery for facilities with high operating hours, and/or high blending percentages.
3. Most turbines on the market can support up to 5% hydrogen blend by volume without major upgrades.

Appendix 1 – Goreway Power Station Study

GE VERNOVA

Capital Power Goreway Hydrogen Conversion Study

August 2024

This document has been modified from its original for public use. This document is intended for informational purposes only and should not be used for any other purpose.

Contents

This report is structured by the following sessions in order, to provide the context and rationale of recommendations:

1. Executive Summary

This report is structured to cover the following sessions in order to provide the context and rationale of project team's recommendations.

- Purpose of Document
- Preamble
- High Level Technical Scopes
- Applicability and Potential Hardware changes
- Recommendation

2. Purpose of Document

The purpose of this document is to provide an overall picture of the hydrogen roadmap for 7FA.04 units in the Goreway facility.

2.1 Preamble

GE VERNOVA is committed to reducing CO_2 emission. Several de-carbonization options are available to accomplish Goreway's objective to increase the share of alternate fuels. Minimizing the impact on the affordability and reliability is an important factor for consideration in the journey of de-carbonization. hydrogen fuel is expected to play a critical role in achieving net-zero emissions.

2.1.1 Energy Diversity

Modern gas turbines are capable of operating on a wide range of H2 concentrations, with multiple commercial power plants having considerable experience. Hydrogen could become an important fuel in the future to generate carbon-free electricity. However, this could result in a hydrogen shortage, potentially creating the need for fuel diversity. Hence, maintaining multiple fuel capabilities (various sources of gas and hydrogen) is needed while developing a more sustainable roadmap.

2.2 Climate Mission

GE Vernova is committed to reduce greenhouse gas emissions. Please see more details in https://www.gevernova.com/sustainability.

3. Prioritized List of Project Scope and Requirements

3.1 Different Technology Options for Reduction of CO2

The project team performed an assessment of two (2) technologies to achieve carbon reduction.

DLN 2.6+ Combustor – The existing combustor can reduce carbon dioxide by burning hydrogen without a large impact to NOx, operational flexibility, and fuel flexibility. There are other facilities throughout the world that are to be commissioned with various hydrogen fuel mixes.

The DLN combustor currently installed in Goreway is capable of burning hydrogen with a minimal adverse impact on NOx, operation flexibility, and fuel flexibility. We investigated blends of three (3) different concentrations of hydrogen. In testing, it was determined that we were approaching the limit of the current Selective Catalyst reducer on the unit, so we moved back to the reduced concentrations of hydrogen to one that was achievable for the operational flexibility and supply.

Advanced Gas Path ("AGP") – The AGP can reduce the amount of carbon dioxide and reduce fuel usage per megawatt by efficiency improvement while maintaining the Combined cycle gas turbine's flexible operation (turndown) and fuel flexibility and NOx emission. Furthermore, AGP has accumulated more than 1 million operation hours worldwide. One of the units has already upgraded to the AGP Technology this last year, and the remaining ones will be installed in the coming years by mid-2025.

3.2 High level Process Safety Assessment

There are additional operational challenges with hydrogen that relate to overall safety.

Hydrogen's lower and upper flammability limits extend to much larger air-fuel ratios than natural gas. The lower flammability limit for methane (in air) is ~5%, while for hydrogen it is ~4%. While autoignition temperature is slightly higher for hydrogen, the minimum ignition energy is 25 times lower than for natural gas. hydrogen leakage poses greater safety hazard than natural gas leakage.

Hydrogen can diffuse through gaskets and seals that might be considered airtight or impermeable to other gases. Therefore, additional sealing systems are used with mixed hydrogen gases, and gaskets can be replaced with welded connections or other appropriate components. A hydrogen leak could create increased safety risks requiring changes to plant procedures, safety / exclusions zones, etc. In addition, there may be other plant level safety issues that merit review.

Normally, if it is an open environment, a small hydrogen leak would unlikely result in an incident unless H2 concentration reaches it flammability range (between 4 to 74 percent concentration in air). Large hydrogen leaks would be of concern in the event of hydrogen concentration in air greater than ~4%.

Fuel leaks in gas turbine and gas valve compartments and mitigation measures would also have to be addressed in the planning and execution of the upgrade. The upgrade may require additional gas detection and or air flow studies of the compartment.

A detailed safety assessment will be performed during modification hydrogen fuel blend operation.

The hazardous area map will have to be updated from the hydrogen once the layout is finalized in the field modification instruction. The location would have to be worked out with the customer as to the best location from a safety and accessibility point.

3.3 Piping Systems

3.3.1 Hydrogen Supply to Blending Skid

Hydrogen piping systems should be designed in accordance with the American Society of Mechanical Engineers (ASME) B31.12 or B31.3 as well as other applicable codes and regulations, and the special or local requirements for hydrogen service. All associated components including valves, seals, hydrogen leakage detection system, sensors shall be manufactured for hydrogen application with appropriate certification.

3.3.2 Accessories Systems Assessment

The hydrogen detection system will require modification depending on the hydrogen concentration in pipes. GE VERNOVA will require an analysis of the compartments that contain hydrogen to determine alarm and trip levels. The balance of plant scope of the plant at Goreway will not be completed as part of any upgrade as these units are located indoors.

The infrared hazardous gas system is adequate for the projected concentrations of hydrogen. The alarm limits may need to be adjusted once the analysis is completed. If the unit is moved to a higher hydrogen content it may be necessary to change the type of sensor on the unit.

The combustion support hoses piping, and materials are not required to be upgraded as the unit is staying at low levels of hydrogen. GE VERNOVA suggest that the plant moves to a latest style gasket for all the piping connections. The connections of the pigtails to both sides are not required to be modified as they are resistant to leaking hydrogen.

The fire system does not require any change at the predicted blend of hydrogen in the fuel. Any increase to the hydrogen percent in the fuel would require further modifications.

A modification to the purge system will be required with the current configuration.

3.4 Blending Skid

A separate H2 circuit would be added to the existing blending skid at Goreway. The new skid will have a vent valve and a safety shut off valve which are required for the hydrogen line and mixer according to GE Vernova recommendations. There would have to be a single skid per unit. The skid would have to be controlled from the GE VERNOVA control system, for safe operation.

GE VERNOVA commercial references of blending skids:

Customer	Frame	Years Of Operation	Location
Dow chemical Company	4*7FA.03	8	USA
CEPSA	1*6B.03	7	SPAIN
Long Ridge Energy Terminal	1*7HA.02	Installed	USA
New York Power Authority	1*LM6000	Under Construction	USA
Tallawarra B	1*9FA.05	Under Construction	Australia

Table 1: Blending skids currently in operation

3.5 Heat Recovery Steam Generator (HRSG)

The exhaust constituents for the gas turbine were studies and were within the operability of the existing unit. No changes are required for the hydrogen fuel changes.

3.6 Impact on Hazardous Operation Zone & ATEX Directive (ATEX)

New hazardous operation zones will be required pending the locations of the H_2 blending skids and on any new venting sources Safety Shutoff Valve (SSOV) and Safety Shutoff Vent Valve (SSOVV) (note this unit already has an existing SSOV and SSOVV for the Methane fuel). Typically, natural gas has an ATEX classification is ATEX IIA for methane, the standard would have to be upgraded to ATEX IIB +H2. for hydrogen

3.7 Impact on Instrumentation

Hydrogen flame has low luminosity. However, at selected fuel composition no changes are required. If the composition of hydrogen is increased, there would be a required change in all the instrumentation in the hazardous operation op area.

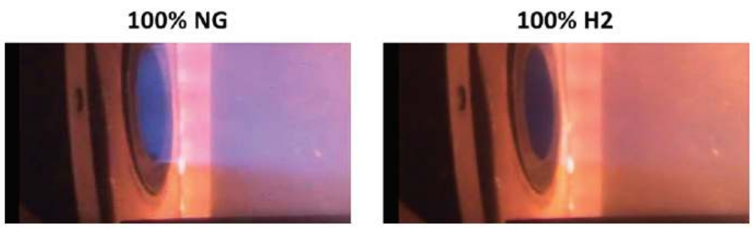

Figure 1: Comparison of hydrogen & natural gas flames, H2 flame is invisible
(Source: GEA 33861)

3.8 High Level Risk Assessment

During the detailed field modification instruction, the team will perform a what-if analysis on preliminary conceptual design.

4. GE VERNOVA's Hydrogen Experience

With the experience learned from nearly 6 million hours operation on hydrogen, GE VERNOVA is developing a pathway to improve its combustion technology to 100% hydrogen. The development will be focused on it is Advanced Dry Low NOx (DLN) for F and HA units, and Dry Low Emission (DLE) for Aero units. A quick summary of GE VERNOVA's experience is shown in Figure 2.

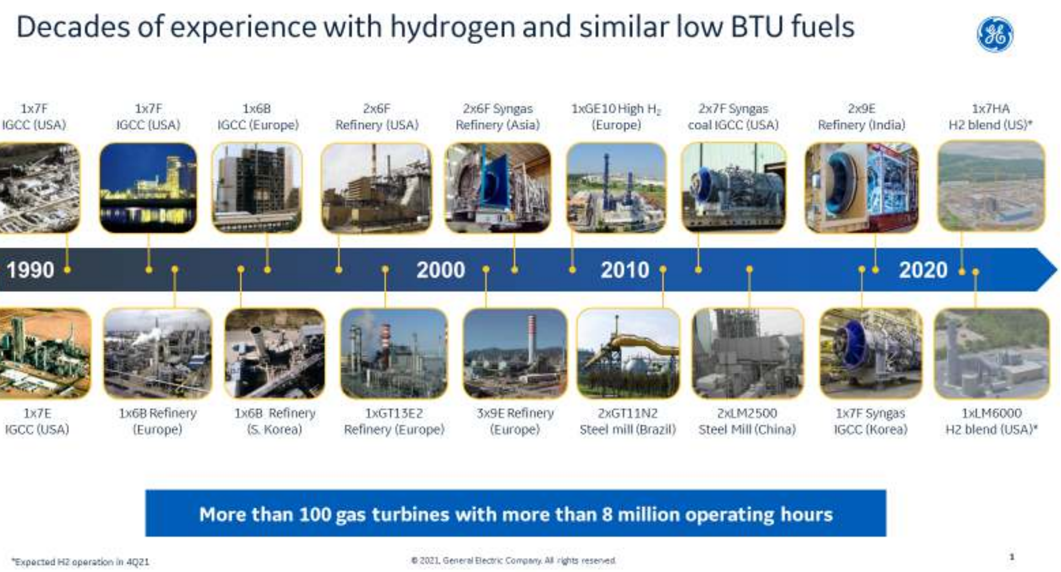

Figure 2: GE VERNOVA's experience with H2& similar low BTU fuels

GE VERNOVA Gas turbine hydrogen capability is shown in Figure 3

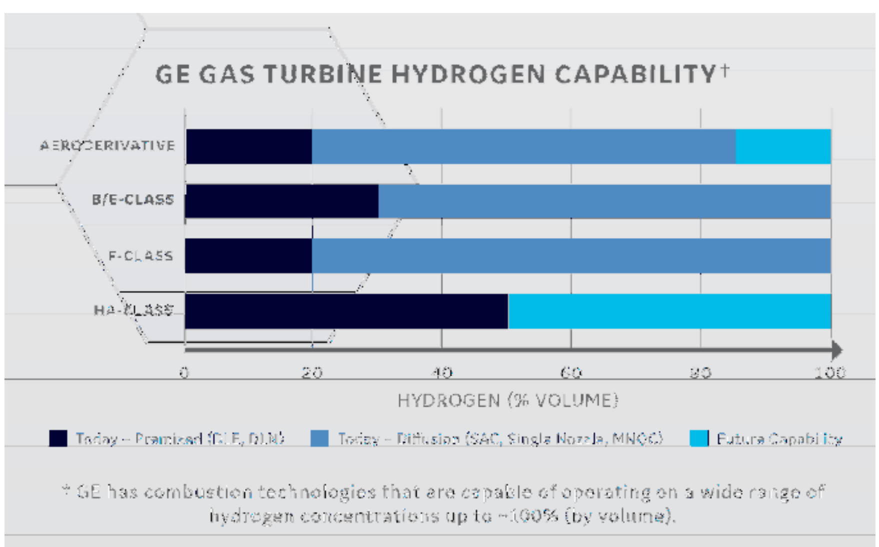

Figure 3: GE VERNOVA Gas Turbine - High Level Hydrogen Capability

Other than the fleet experience on hydrogen, GE VERNOVA can conduct its lab test to extend the capability from current 50% H2 to 100% H2 as shown below in Figure 4.

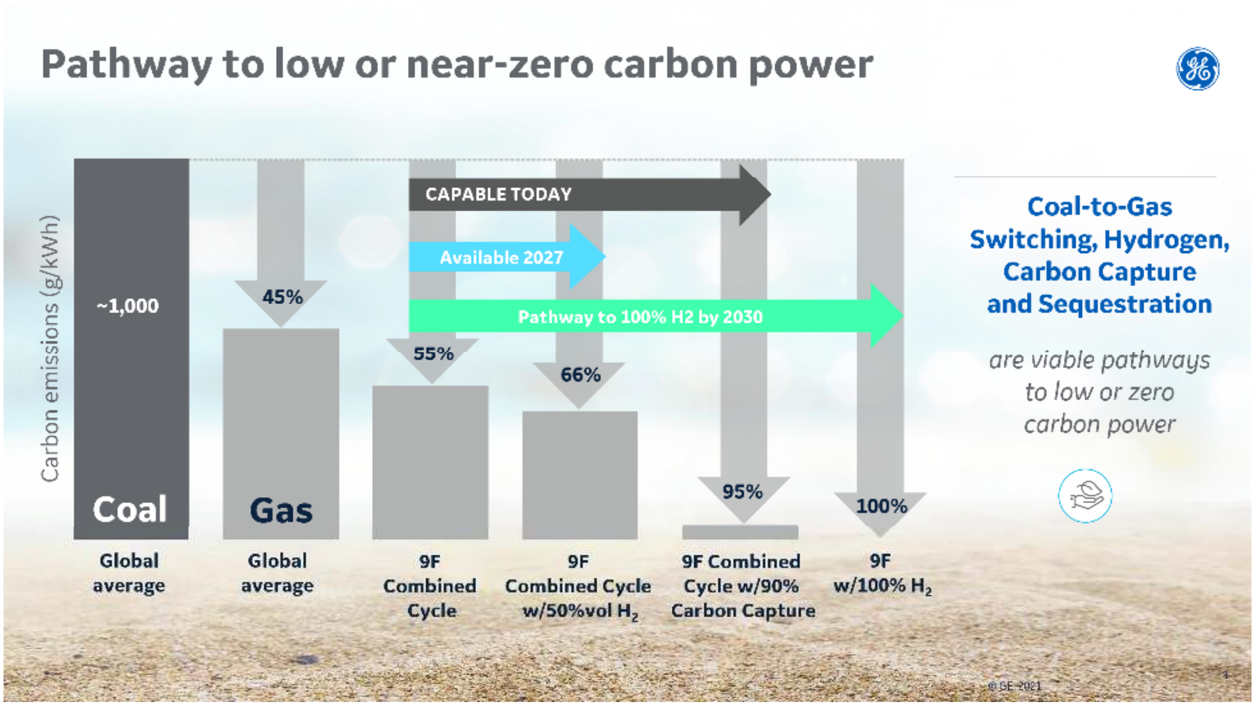

Figure 4: GE VERNOVA's pathway to low or near-zero carbon power specific to 7F Units

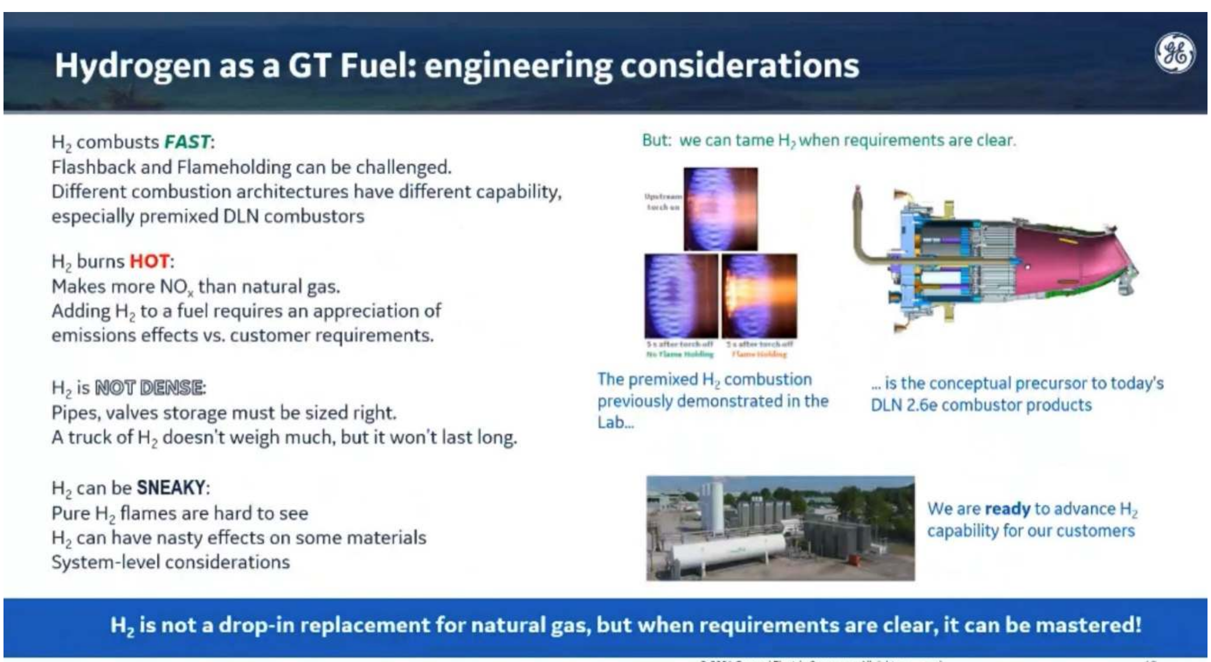

Figure 5: Hydrogen Fuel Engineering Considerations

5. Results

The existing machine is capable of operating with a blended hydrogen fuel. The machine will not exceed the operational limits of the HRSG or generator. The hardware for the upgrade to burn a Hydrogen mix will be minimal on the existing machine. A new mixing skid will be necessary as well as controls to supervise the skid operation, sealing mechanisms within the turbine base will have to be upgraded.

A few important factors to be considered are listed below.

- Hydrogen is more flammable than natural gas and additional safety measures may be necessary.
- GE Vernova has commercial references for other frames (6F,7F, 9E and 6B) operating up to 100% hydrogen.
- NOx emission increases with incremental increases of hydrogen in the fuel.
- Hydrogen price is high (2.5~3X of Gas Price).

Appendix 2 – York Energy Centre Study

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Capital Power Corporation
York Energy Centre SGT6-5000F Simple Cycle Hydrogen Co-Firing Assessment

A Feasibility Study

2024-04-03 / Orlando, FL

siemens-energy.com/decarbonization

Capital Power Corporation
York Energy Centre SGT6-5000F Simple Cycle Hydrogen Co-Firing Assessment

A Feasibility Study
Final Report
Submitted on April 3, 2024

Executive Summary

Hydrogen co-firing at York Energy Centre SGT6-5000F Simple Cycle plant.
The present configuration of the SGT6-5000F at the York Energy Centre can allow Hydrogen (H2) co-firing with a natural gas H2 blend with up to 30vol% with the upgrade of the existing burner system to ULN 3.0. Due to the low density of H2 compared to Methane / Natural Gas, the relation of volume H2/CH4 ratio to energy respectively CO2 reduction is not linear. A natural gas blended with 30vol% of Green Hydrogen reduces the CO2 emissions by about 11% compared to operation with natural gas only.

The following equipment needs to be added and/or upgraded to be Hydrogen-compliant.

- Adding a Hydrogen – Natural Gas blending system into the fuel supply system, upstream of the final filter. The blending system is installed on a prefabricated skid that contains the required measurement devices, fast-acting control valves and actuators as well as the mixing device.
- Replacing the existing downstream piping and the final filter with high-quality stainless steel to reduce the risk of Hydrogen embrittlement.
- Modification of plant and GT controls to adjust the Hydrogen content to the desired value, to tune the burners to the changed fuel properties and to protect the system from unwanted operation conditions.
- Review and adaptation of fire and explosion protection concept of the plant, addition of Hydrogen sensors at critical positions.

The results of this feasibility study were presented to Capital Power in February 2024, during a site visit at the York Energy Centre.

This report gives further details of the feasibility study.

1. Table of Contents

2. List of Abbreviations

1	AACE	Association for the Advancement of Cost Engineering
2	BoP	Balance of Plant
3	PP	Combined Cycle Power Plant
4	DCS	Distributed Control System
5	FEED	Front End Engineering and Design
6	HHV	High Heating Value
7	KKS	Plant Coding System ("Kraftwerks Kennzeichungs System")
8	LHV	Low Heating Value
9	MECL	Minimum Emission Compliant Load
10	NOx	Nitrogen Oxides, mainly NO_2, "laughing gas"
11	ppmvd	unit of concentration: parts per million, volumetric dry
12	SEI	Siemens Energy Inc.
13	TSSA	Technical Standards and Safety Authority, Canada
14	ULN	Ultra-Low Nitrogen Oxide (burner technology for low emissions)
15	VOC	Volatile Organic Carbon (not combusted fuel in exhaust gas)
16	WI	Wobbe Index (parameter for energy delivered from burner nozzle)

3. Boundary Conditions

3.1. Contractual basis (excerpts)

The scope of this study is described in the Siemens-Energy proposal SF232084768 R.3 dated October 30th, 2023. This report is the deliverable for customer PO 897244.

The scope of this feasibility study is stipulated as follows:

2. Base Study – Hydrogen Co-firing

The intent of each study will be to evaluate the following:

2.1. Hydrogen co-firing potential of the existing GT combustion system, modification options (including GT auxiliaries) and effect of hydrogen co-firing on combustion metrics

2.2. Definition of H2 – natural gas mixing requirements in respect of control, monitoring and protection

2.3. High-level outlook of GT and plant performance for co-firing of hydrogen up to 30% by volume.

2.4. Expected hydrogen consumption for different levels of hydrogen co-firing

2.5. Evaluate and outline potential requirements to expand/modify existing gas supply systems with the blending of hydrogen

2.6. Implications for plant safety, gas detection, and fire protection systems

2.7. Performance impact of hydrogen co-firing within the limits of the air permit (considering the effect of the currently installed SCR system as applicable)

2.8. As applicable: HRSG & flue gas system (including SCR and ammonia forwarding and distribution system): Effect of co-firing scenarios on downstream equipment and overall plant performance and emissions.

3.2. Physics of Hydrogen

Hydrogen has some unique properties which need to be considered when adapting a PP designed for natural gas to work with a blend of Hydrogen and Methane / natural gas.

- As it is common for the oil & gas industry, the power industry refers to Hydrogen content on a volumetric base. Compared to Methane, the volume-related energy content of Hydrogen is only about a third of the volumetric content.

  Example: a natural gas blend with 30vol% Hydrogen contributes only 11.4% of the energy with carbon-(CO_2)-free Hydrogen.

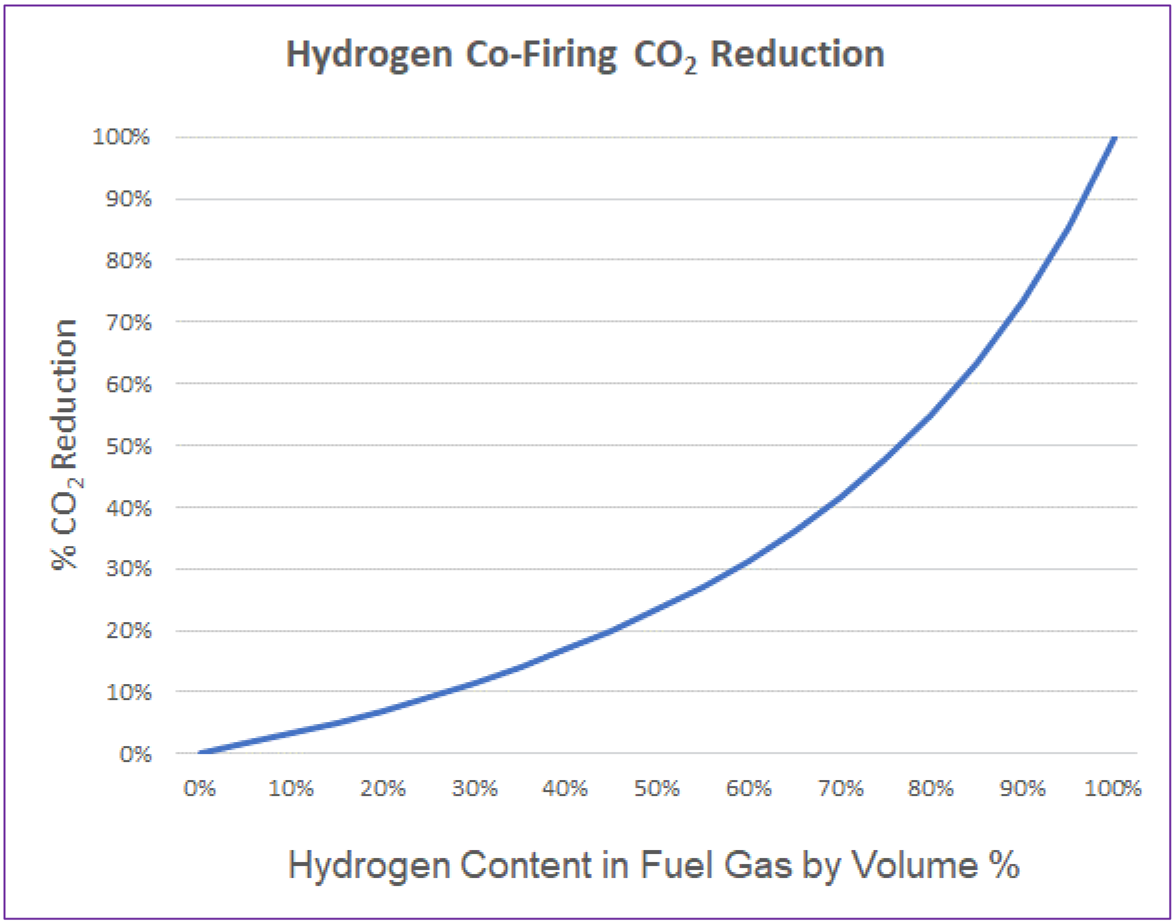

Fig. 1: Energy content and CO_2 reduction vs volumetric content of Hydrogen/Methane blend

- Hydrogen is a very light gas. The density of Methane CH_4 is eight times higher
- Hydrogen has a high weight-related heating value

- The ratio of High Heating Value (HHV) and Low Heating Value (LHV) is higher than in Methane (CH4: +11%; H2: +18%)
- Flame speed of Hydrogen is considerably higher than in Methane
- Hydrogen has – in our applications – a negative Joule Thompson coefficient and gets warmer when throttled
- Hydrogen needs more power and generates more heat during compression than Methane, which requires an intercooler after every compression stage.
- The Wobbe Index (WI) - a key parameter to define the energy supplied by a burner nozzle – of pure Hydrogen is 20% lower than the WI of Methane.

	Hydrogen content vol-%	0 (pure CH_4)	15%	30%	100% (pure H_2)
	Hydrogen content Energy-%	0	5.04%	11.4%	100%
	Hydrogen content, mass-%	0	2.16%	5.1%	100%
	LHV heating value [BTU/lb]	21,500	22,150	23,000	51,600
	HHV heating value [BTU/lb]	23,900	24,650	25,750	61,000
	Wobbe Index [MJ/Nm^3]	48.2	47.1	46.0	40.9

Table 1: Properties of Methane and Hydrogen

3.2.1. Safety Aspects of using Hydrogen in Power Plants

Some general safety information about hydrogen is listed below and detailed in Figure 2.

Hydrogen (H_2):

- is non-toxic
- is much lighter than air
- is easily diluted in air and rapidly accelerates vertically out of the leakage area
- is highly flammable and should always be kept separated from air/oxygen gases particularly by purging oxygen containing gases out of the system with inert gases
- has an explosion risk like that of methane and other highly flammable gasses
- requires the use of different group for fire and explosion protection (for example)

NFPA 70 National Electric Code equipment classes:

Methane: Class I, Division II, Group D

Hydrogen: Class I, Division II, Group B

Parameter	Unit	Methane	Hydrogen
Relative density (to air)		42%	7%
Diffusion coefficient (20°C)	cm²/s	0.21	0.76
Lower explosion limit LEL		5%	4%
Upper explosion limit UEL		15%	75%
Auto ignition temperature	degC	537	560
	degF	999	1040

Fig. 2: Safety-related physical properties of hydrogen and methane, excerpt

Before introducing hydrogen as a gas turbine fuel at a power plant, it is an absolute requirement that all H_2 and fuel gas related systems are carefully reviewed, tested according to the applicable codes and standards, and approved by the local fire and explosion protection authority. The most critical, but not the only, aspect to safely using hydrogen in the plant is to always keep it separated from oxygen. The only time the hydrogen should be allowed to mix with oxygen is in the CT burners and at the exits of vent lines where it enters the atmosphere.

3.2.2. Material Recommendation for handling Hydrogen-blended natural gas

Based on experience of Siemens Energy gas turbines operating with Hydrogen and on literature available in this field, we recommend the following materials:

For unheated Hydrogen up to 100%, the oil & gas industry is using carbon steel, like API 5L X52, with good experience. We recommend this material for the Hydrogen forwarding piping from the H2 production facility to the blending skid.

Since Hydrogen has the tendency to diffuse into carbon steel and reduces ductility, carbon steel is not utilized when the component is exposed to preheated Hydrogen-blended natural gas and/or is subject of thermal stress during start or load changes. The Hydrogen embrittlement effect is increasing with higher temperature and high Hydrogen partial pressure. The impacted systems are the blending skid, the fuel gas system downstream of the blending skid including final filter and the GT fuel gas piping manifold.

For applications in F-class units up to 10vol% Hydrogen, ASTM A312 TP304 stainless steel (DIN EN 1.4301 / X5CrNi18.9) is sufficient to avoid / reduce Hydrogen embrittlement. It is recommended that the operation time with blended Hydrogen is recorded, and the system is inspected regularly. Local regulations, e.g. by the TSSA, need to be considered.

For applications with permanent operation up to 30vol%, the low carbon version of the ASTM A312 TP316L (DIN EN 1.4404 / X2CrNiMo17-12-2) is recommended. (Source SANDIA report 2012-7321).

Since the material cost differences between 304 and 316L are small, it is recommended to design all new installed thermal systems which will be exposed to hot Hydrogen-blended gas with the material with higher embrittlement resistance 316L.

3.3. Climate at York Energy Centre

The York Energy Centre is located in Newmarket, approximately 60 km north of Toronto, in south-east Ontario.

The elevation is about 780ft (240m) above sea level. In Newmarket, the summers are warm; the winters are freezing, snowy, and windy; and it is partly cloudy year-round.

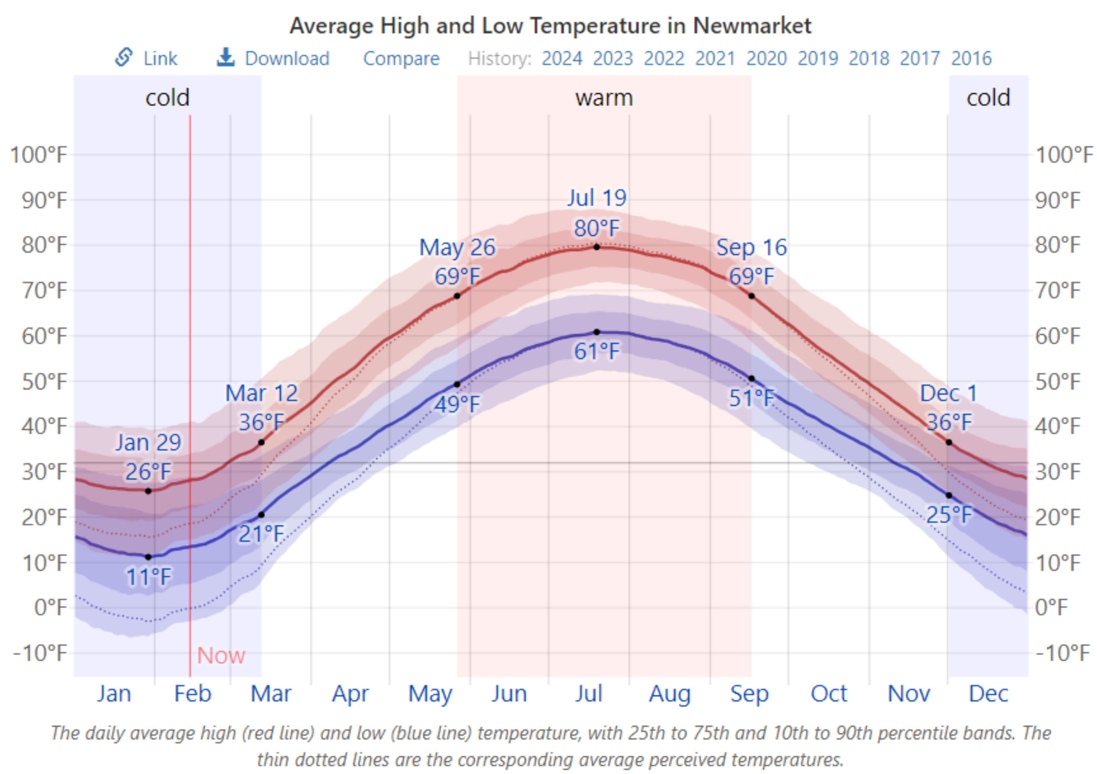

Fig. 3: Typical temperatures and variations at Newmarket, Ontario (source: www.weatherspark.com)

3.4. Price estimate accuracy

This feasibility study includes an estimate of the required investment volume for H2 co-firing up to 30vol%. The estimate is based on today's cost level for similar projects in Canada. The accuracy of price estimates is related to the degree of engineering completed. A feasibility study is typically including ~5% of the required engineering work, equivalent to a class 4 estimate according the AACE classification.

	Primary Characteristic	*Secondary Characteristic*		
ESTIMATE CLASS	**MATURITY LEVEL OF PROJECT DEFINITION DELIVERABLES** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]
Class 5	0% to 2%	Concept screening	Capacity factored, parametric models, judgment, or analogy	L: -20% to -50% H: +30% to +100%
Class 4	1% to 15%	Study or feasibility	Equipment factored or parametric models	L: -15% to -30% H: +20% to +50%
Class 3	10% to 40%	Budget authorization or control	Semi-detailed unit costs with assembly level line items	L: -10% to -20% H: +10% to +30%
Class 2	30% to 75%	Control or bid/tender	Detailed unit cost with forced detailed take-off	L: -5% to -15% H: +5% to +20%
Class 1	65% to 100%	Check estimate or bid/tender	Detailed unit cost with detailed take-off	L: -3% to -10% H: +3% to +15%

Notes: [a] The state of process technology, availability of applicable reference cost data, and many other risks affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.

Fig. 4: Estimate classes and expected accuracy range (source: AACE International 18R97)

4. Hydrogen Co-Firing at York Energy Centre SGT6-5000F Simple Cycle

This section describes the influence of Hydrogen co-firing on the key performance parameters of the SGT6-5000F Simple Cycle gas turbines installed at York Energy Centre. It describes the required modifications of existing equipment and additional equipment required for safe and reliable co-firing of Hydrogen blended into local fuel gas.

The objective of the use of Hydrogen is the reduction of the carbon footprint of the PP. The CO2 reduction is only environmentally relevant if the used Hydrogen is produced with surplus renewable energy, which otherwise would be curtailed i.e. the wind or PV generation would be switched off. The Hydrogen is stored in trucks and brought to site until the demand of electricity can't be satisfied with renewable energy alone and fossil generation must be engaged. With increasing renewable energy, the operational scheme of fossil plants is changing from base load to load-following operation in a daily start-and-stop scenario.

As peaker / standby units, the SGT6-5000F simple cycle engines at York Energy Centre are suited to operate successfully in an environment with a high degree of renewable generation and the use "green" Hydrogen to further reduce the PP carbon footprint.

4.1. Impact on Performance

Following an FX upgrade planned in Spring 2025, the SGT6-5000F at York Energy Centre will be equipped with a ULN 3.0 burner which is suitable to burn up to 30vol% H2 blended to the natural gas.

Validation measurements are required for the SGT6-5000F for first engine implementation for each step of H2 cofiring vol% (1-30%). This validation will be done under realistic conditions at the first unit converted to Hydrogen co-firing at site.

To avoid an exchange of the fuel gas heater to a H2 capable material and design, the Hydrogen is blended into the preheated fuel gas downstream of the fuel gas heater, thus reducing the resulting fuel gas temperature, and typically contributing to the lower plant efficiency. However, there are no performance heater systems for the York Energy Centre power plant. Therefore, the H2 injection downstream of the performance heater is not applicable.

4.2. Impact on Emissions

The ULN 3.0 burner is designed for low NOx emissions with Methane and typical pipeline quality natural gas. This combustion performance is maintained also with Hydrogen blended into high-quality natural gas. Up to 30vol% Hydrogen, the combustion system is designed to keep NOx emissions at 9 ppmvd @ 15% O_2.

It should be noted that the FX upgrade guarantees for NOx are 12 ppmvd @ 15% O_2. The 9 ppmvd emission value used in this feasibility study is not a guarantee and is applied based on available performance data curves for use with hydrogen co-firing performance calculations.

The operation of the PP with Hydrogen is limited to the load range from Minimum Emission Compliant Load (MECL) to base load, where CO emissions are very low. Since Hydrogen does not add any Carbon to the combustion process, there is no change of CO emissions expected.

The emissions of CO2 are directly correlated to plant efficiency and – if the Hydrogen is produced carbon-free as “Green“ Hydrogen – the amount of H2 co-firing.

Other emission factors like particulates or volatile organic carbons VOC are not influenced by Hydrogen co-firing.

4.3. Impact on Air Permit Limits

With tuning of the combustion system for Hydrogen co-firing after FX upgrade and burner tuning during commissioning, it is expected that the plant can be operated within the emission levels as stipulated in the air permit. Post performance upgrade air permit is expected to be 20 ppmvd NOx at peak firing.

4.4. Impact on Operational Profile

Start and Stop – Natural Gas Only

The ignition and combustion system of the SGT6-5000F is optimized for natural gas. To minimize effects of Hydrogen on the start quality (i.e. avoiding of failed starts) or start-up emissions, it is recommended to blend Hydrogen only when the GT is operating between MECL and Base Load.

Peak firing is not permitted with hydrogen co-firing. Simultaneous peak firing and hydrogen co-firing is not permissible.

The SGT6-5000F and the PP are designed for moderate to high ramp rates. No impact of Hydrogen co-firing on ramp rates or start-up and shut-down times is expected.

Before the unit is shut down, the Hydrogen blending into the natural gas should be discontinued, so that for the stand-still and re-start of the unit, the entire fuel gas system is filled with natural gas only. This is recommended to prevent Hydrogen and fuel gas separation within the system during stand-still; avoiding that pipe sections containing a higher degree of Hydrogen interfere with the following start-up procedure.

Following an unforeseen trip of the gas turbine when operating with Hydrogen-blended gas, the fuel gas system is filled with Hydrogen – fuel gas mixture. In the event of this occurrence, it is necessary to vent the fuel gas system and release the remaining Hydrogen-natural gas mixture into the atmosphere, in order to avoid interference with the re-start. The stipulation of an environmentally acceptable re-start procedure is subject of the commissioning process of the ULN 3.0 burner system with Hydrogen.

Optimizing Hydrogen Usage – Minimum H_2 Content for the Longest Possible Time

Up to 5% Hydrogen, the impact on heat rate respectively the net efficiency of the entire plant is marginal. When the Hydrogen content exceeds10vol%, the consequential increase of heat rate becomes noticeable. Therefore, the most effective use of Hydrogen is within the optimal operation range “sweet spot” between 5% to 10vol% operation of Hydrogen. An increase of Hydrogen levels beyond 15vol% may make sense only out of operational aspects of Hydrogen Production and Storage, e.g. to empty the storage tanks before a long, sunny weekend with no plant operation but plenty of surplus PV renewable generation available to be converted into Hydrogen.

4.5. Gas Turbine Burner Upgrade

The existing burner system of the two SGT6-5000F at York Energy is of the ULN 2.0 type and is not released to burn Hydrogen. A ULN 3.0 burner is required, and this burner upgrade is planned for both GTs to be installed spring of 2025

The next generation ULN 3.0 burner with improved pre-mix capability was designed for ultra-low NOx combustion in “dry” conditions, i.e., without any injection of steam or water for flame temperature control. The design of the burner provides a more intense mixing of fuel and air upstream of the combustion zone, thus providing a lean flame and low flame temperature with moderate hot zone temperature.

The scope of the FX upgrade and change to ULN 3.0 burner is not covered in this report. The GT performance calculations with hydrogen co-firing are considered for post-upgrade conditions only.

4.6. Gas Turbine Auxiliaries Impact and Feasibility Assessment

Additional changes are required for the gas supply system of the gas turbines to make sure that all components like valves and filters are suitable for operation with Hydrogen-blended natural gas. The piping material is typically made out of low-grade stainless steel and still carries the risk on H2-embrittlement and reduced flexibility and reduction of lifetime in cycling operation. The recommendation is to address H2 embrittlement risk, which increases with the gas temperature and the H2 partial pressure inside the system, with an exchange of all piping and components which will come into long-term contact with hot H2-blend above 10vol% with high grade stainless steel such as ASTM 316L. Details of the recommended upgrades are summarized in the following sections.

The gas turbine auxiliary systems were analyzed to assess the impact of hydrogen cofiring on the existing equipment, as well as to verify the applicability of an existing hydrogen/natural gas blending skid design. The analysis considered up to 30vol% hydrogen blended with the existing natural gas supply at base load operation.

Results of the analysis indicate that the existing fuel gas system sizing, including throttle valves and piping, is sufficient for this application. However, the pipe and component materials will eventually need to be changed from 304 stainless steel to 316/316L stainless. The material change will not need to be completed immediately and can be staged over later outages to mitigate the cost impact.

The analysis also indicated that the existing Siemens Energy blending skid and mixing valve designs can be used at York Energy, with possible changes to accommodate the requirement to operate at -40C ambient temperatures per CAN/BNQ 1784-000.

Finally, the impact of a possible change to the GT enclosure hazardous location rating from Class 1 Div 2 Group D to Group B was assessed for the existing electrical equipment. The assessment indicated that the existing instrumentation is designed for installation in a Group B enclosure.

A summary of the findings is listed below:

- Existing fuel gas system design and sizing sufficient for 30vol%.
- Existing fuel gas piping and valve body materials can be used for near term cofiring operation but will need to be replaced for long term operation. A 10x reduction in the life should be applied when hydrogen is being used. Eventual material change will mean replacement of 304 stainless piping with 316L stainless, and replacement of carbon steel valve bodies with 316/316L stainless valve bodies.
- Siemens Energy blending skid design is sufficient for York H2 cofiring up to 30vol%. Only change to existing design will be to the throttle valve if -40°C ambient temperature requirement is imposed.
- Review of electrical equipment currently installed inside of the GT enclosure revealed that all equipment is rated to be installed in a Class 1 Div 2 Group B location.

4.6.1. Hydrogen Flow Rate

Table 2 shows the hydrogen flow rates used in the analysis of the CT auxiliaries. The -10°C and 30°C ambient temperature cases were used as they represent the highest and lowest steady state flow rates. Only base load operation was considered for this analysis – there are no part load cases with hydrogen cofiring analyzed here.

Ambient Temperature °C	Natural Gas Supply Pressure bar	Hydrogen Supply Pressure bar	Hydrogen Concentration vol% H2	Total Mixed Fuel Flow kg/h	Hydrogen Flow kg/h
-10	34.5	40.0	5%	45,037	296
			15%	44,024	955
			30%	41,556	2,124
30	34.5	40.0	5%	40,601	267
			15%	38,812	842
			30%	34,878	1,783

Table 2 – Hydrogen Boundary Conditions

Note that the hydrogen supply pressure target of 40 bar is based on results of the mixing valve calculation described in subsequent sections of this report. The natural gas supply pressure is based on York Energy operating data.

4.6.2. Natural Gas Conditions and Piping Pressure Class

The hydrogen cofiring analysis performed here was confined to the natural gas pressure and temperature originally provided in the Customer Process Connections document provided to York Energy as a new unit. This document, CA1007-XK01-MB-013100, indicates the min and max natural gas pressure and temperature at the gas turbine fuel gas system boundary, which is the flange on the upstream side of the fuel gas filter separator. These values are provided in Table 3, and were included in calculations to verify the pipe and valve sizing.

	Min	Max
Pressure, bar	31	36.2
Temperature, °C	15.6	40.6

Table 3 – Fuel Gas Supply Connection Conditions

Note that most of the results in this report are provided at the nominal pressures listed in Table 2, but analysis was performed at a wider range of conditions in order to verify margin is built into the system.

The fuel gas piping system design temperature and pressure are provided in Table 4, along with the pressure class of the piping system. This represents the design limitations of the piping itself, and represent a wider range of values than the actual process conditions.

Design Pressure	600 psig	41.4 bar
Design Temperature	150°F	65.6°C
Pipe Pressure Class	300#	

Table 4 – Fuel Gas Piping Design Conditions

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4.6.3. Fuel Gas Pipe Sizing

The existing fuel gas pipe sizing was checked to verify that it can handle the change in volumetric flow that comes with mixing the lighter hydrogen with the natural gas supply. Table 5 shows the velocity in the 8in fuel gas supply pipe (before the gas splits into stages), and the straight run pressure drop.

Ambient Temperature °C	Hydrogen Concentration vol%	Mixed Fuel Flow kg/h	Flow Velocity m/s	Flow Velocity ft/s	Pressure Loss bar/100m	Pressure Loss psi/100ft
-10	5%	45,037	17.7	57.8	0.203	0.90
	15%	44,024	19.0	62.3	0.213	0.94
	30%	41,556	21.2	69.4	0.234	1.03
30	5%	40,601	15.9	52.1	0.199	0.88
	15%	38,812	16.8	54.9	0.200	0.89
	30%	34,878	17.8	58.3	0.198	0.87

Table 5 – Fuel Gas Pipe Velocity and DP with Mixed Fuel Flow in 8in Pipe

Siemens Energy's velocity and pressure loss design limits for auxiliaries piping are 200 fps (60 m/s) and 4 psi/100ft (0.9 bar/100m), respectively. Even with 30vol% H2 the fuel flow velocity and pressure drop are well within these limits.

4.6.4. Impacts to Existing Fuel Gas Throttle Valve Sizing

The fuel gas throttle valves were also checked to verify they can handle the changing volumetric flow due to the hydrogen mixture, as well as the increase in fuel flow due to the FX upgrade. Operating data was used to check the current margin in the valves, and to verify the calculation method. It was also checked to determine the base load fuel fractions which were used in the calculation (these fractions could change due to combustion tuning changes).

4.6.5. Piping and Component Materials

The current fuel gas system piping is A312 TP304 stainless steel; and the throttle valves, over speed trip (OST) valve and vent valve are carbon steel. Operating this system with a flow of any concentration of hydrogen gas over time will lead to embrittlement of the material. As such, it is Siemens Energy's position that all of the piping and valves should eventually be upgraded to be manufactured from 316/316L stainless steel.

The risk of embrittlement is a long-term risk, so the current fuel gas system materials can be used as-is in the near term. A life reduction factor of 10 is applied anytime the system runs with hydrogen mixed into the fuel supply. So, for a permanent co-firing installation, the material change will eventually be required, but can be implemented over time.

The following components are affected by this change:

- Fuel Gas Interconnect Piping
- Fuel Gas Stage Manifold Piping
- Fuel Gas Flex Hoses
- Main Fuel Filter/Separator
- Fuel Gas Overspeed Trip Valve (OST)
- Fuel Gas Vent Valve
- Fuel Gas Stage Throttle Valves

4.6.6. Hazardous Location Instrumentation Review

As noted in the review of the hazardous location classifications associated with adding hydrogen co-firing to York Energy, there are areas previous classified as Class 1 Division 2 Group D which are now to be classified as Class 1 Division 2 Group B. Typically, the instrumentation purchased for application in gas turbines is specified to be at least Group D compatible, but vendors who supply these instruments do not usually carry many separate classifications. As such, any instrument that is Group D compatible tends to be compatible with all Class 2 Div 2 groups.

A review was made of the CT auxiliary instrumentation installed in the existing and new classified hazardous locations. All of electrical instrumentation reviewed was found to be compatible with Group B, so there will be no significant changes to the gas turbine instrumentation required.

4.7. Design Concept of Blending System

The core element of the blending system is a blending skid for each gas turbine, which includes the H2 flow measurement and the fast-acting H2 flow control valve.

An additional (optional) gas pressure reduction valve (Natural Gas Blending Valve) is useful when the H2 supply comes from a Hydrogen storage facility and low H2 pressure demand is helpful to increase the useful volume of stored Hydrogen between maximum design pressure of the storage tanks and minimum H2 pressure demand of the power plant. However, This pressure reduction valve is not needed in the case of York Energy Centre, as the hydrogen will be trucked in and pressure reduction will be handled prior to reaching the H2 blending skid.

The task of the Hydrogen blending system is to

- Control the Hydrogen flow to the Hydrogen content selected by the operator, considering the load and natural gas flow
- Measure the flow of Hydrogen with high precision as an input parameter to the burner management control software
- Phase-in the Hydrogen at MECL
- Phase-out the Hydrogen when the unit is about to shut down or when No-H2 Peak Power is required
- Protect the gas turbine from a sudden change of fuel composition, e.g. when the supply of Hydrogen or natural gas is suddenly interrupted
- Provide adequate mixture of Hydrogen and natural gas to form a homogeneous fuel gas

Therefore, the blending skid as the core element of the system is equipped with a high-precision Hydrogen flow meter using the Coriolis measuring principle. A Coriolis meter is directly measuring the mass flow with little to no pressure loss and has a very wide measuring range to also precisely measure the Hydrogen flow when a very low H2 co-firing rate (e.g. 5vol%) is selected by the operator and the plant is operating at MECL. The measured mass flow is converted to Hydrogen vol%. The control of the Hydrogen flow is done by a fast-acting control valve. A larger control valve is modulating the natural gas flow so that the resulting fuel gas flow matches the actual gas turbine consumption. A Hydrogen isolation valve with pneumatic drive is installed when no Hydrogen blending is requested.

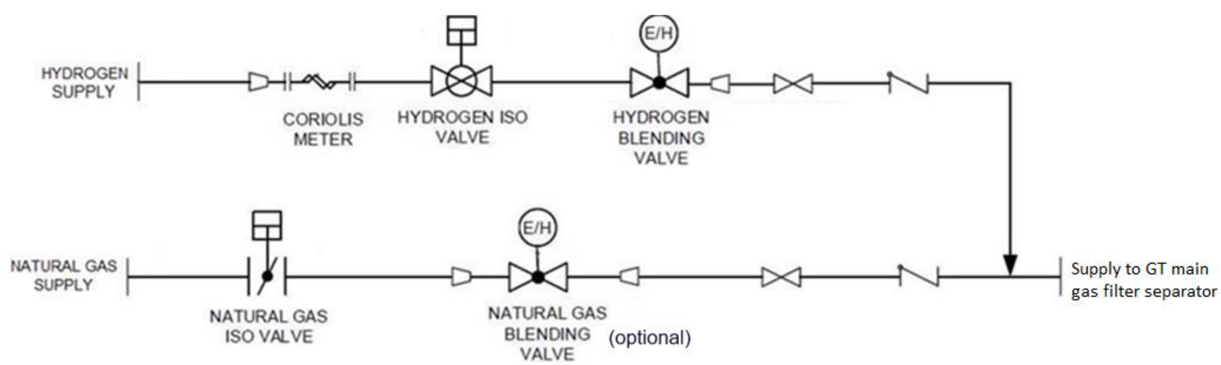

Fig. 5: Functional sketch of blending skid

The measurement and control devices are integrated into the gas turbine controller. Communication of setpoints, actual measurement data and alarms are routed through the gas turbine controls and communicated to the DCS of the plant. An update of the plant and gas turbine control software is required before the gas turbine is commissioned. The design of the control software is subject of detailed design during the implementation phase.

The sizing of the components including the blending skid is for cold day operation with 30vol% Hydrogen. This allows for operation at between MECL on hot days with low percentage and base load up to 30vol% Hydrogen. A design margin of about 10% is considered. Due to the low-flow characteristic of the measuring technology, the accuracy of the blending system is lower at low H2 flows, which is not expected to have any impact on plant operation.

Each of the two gas turbines will be equipped with a separate blending skid to allow individual start and H2 blending. The blending system will be delivered as two pre-fabricated and pre-tested skids to site to minimize installation and commissioning work.

The existing skid is designed conditions are provided in Table 7.

Max Design Pressure	750 psig	51.7 bar
Design Temperature	150°F	65.6°C
Design Flow Rate	2270 kg/h*	
Pipe Pressure Class	600#	

Table 7 – Blending Skid Design Conditions

*Note – This design pressure is specified for the existing hydrogen blending skid design. A design margin factor of 1.1 has been discussed and would increase the design pressure to 2336 kg/hr. This design flow rate can be assessed in a future phase of the project for the existing equipment.

The piping is 3in diameter, 600#, 316L stainless steel. Hydrogen is controlled via a 2in hydraulic throttle valve, and there are two pneumatic isolation valves surrounding a pneumatic vent valve used as a double block and bleed to isolate the hydrogen from the natural gas supply when cofiring is not in operation. A manual isolation valve is provided, as well as connections for a nitrogen purge gas supply.

A Wobbe index meter will be installed in the mixed gas flow - in the existing fuel gas piping downstream of the filter/separator. Hydrogen temperature and pressure will be measured at the skid as well.

Note that the blending skid is designed as a Class 1 Div 2 Group B hazardous location, and all of the associated electrical equipment is rated appropriately.

4.7.1. Mixing Valve Calculations

The mixing valve considered here is a hydraulically actuated control valve and is the same type of valve used for the fuel gas control. These valves have an excellent response and controllability over a wide range of valve positions.

The mixing valve position was calculated over a range of hydrogen flows and supply pressures in order to verify its applicability for the specific target process conditions proposed for York Energy. This calculation was also used to determine the minimum and nominal operating pressures for the hydrogen supply.

Note that the hydrogen supply pressure is really a delta based on the natural gas pressure. In this calculation results are presented for a natural gas pressure of 34.5 bar but were verified for the same pressure differences over the range of supply pressures shown in Table 2.

Table 8 shows the results of the mixing valve calculation. The results are shown for the nominal operating hydrogen pressure, the minimum hydrogen pressure to maintain control of the mixing valve, and the design maximum hydrogen pressure of the blending skid.

Ambient Temperature °C	Natural Gas Pressure bar	Hydrogen Pressure bar	Hydrogen Concentration vol%	Hydrogen Flow kg/h	Mixing Valve Position % open
-10	34.5	40.0	30%	2124	60.6%
30			5%	267	25.9%
-10	34.5	51.7	30%	2124	48.5%
30			5%	267	11.8%
-10	34.5	36.5	30%	2124	76.4%
30			5%	267	35.8%

Table 8 – Mixing Valve Calculation Results

The results of the calculation indicate that a nominal hydrogen supply pressure of 40 bar allows for good valve control and provides for some margin in the natural gas supply.

Ideally the mixing valve will not be allowed to go above approximately 75% open, and the calculation shows that the hydrogen pressure should remain at minimum of 2 bar above the natural gas pressure in order to stay withing the controllable range of the valve. The calculation also shows that the valve stays within the low side of the controllable range at low flows – the valve will be at 11.8% open at the min flow case with the supply pressure at the maximum design limit of the skid.

4.7.2. Blending Skid Pipe Sizing

The blending skid was designed for 2270 kg/h of hydrogen flow, which is not exceeded by the York energy max hydrogen flow case (per Table 2). The results of a calculation of the pipe velocity and straight run pressure loss for 3” pipe is given in Table 9.

Ambient Temperature °C	Hydrogen Concentration vol%	Hydrogen Flow kg/h	Flow Velocity m/s	Flow Velocity ft/s	Pressure Loss bar/100m	Pressure Loss psi/100ft
-10	5%	296	5.3	17.2	0.010	0.04
	15%	955	16.9	55.4	0.079	0.35
	30%	2,124	37.7	123.3	0.523	2.31
30	5%	267	4.7	15.5	0.009	0.04
	15%	842	14.9	48.9	0.073	0.32
	30%	1,783	31.6	103.5	0.284	1.26

Table 9 – Piping Velocity and Pressure Loss

4.7.3. Cold Ambient Temperature Considerations

There has been some discussion regarding the of the application of CAN/BNQ 1784-000, which would require a cold ambient temperature rating of -40°C for the blending skid equipment. The mixing valve that is currently specified for the blending skid is not able to meet this cold ambient requirement due to seal materials, but Siemens Energy is working on a solution. The cost of the seal materials is assessed as negligible relative to the project costs. As of the release of this study there are options being pursued to deal with this non-compliance, including identifying new seal materials and looking into an exemption from the requirement.

4.7.4. Arrangement of the Blending system

The blending skids would be ideally located as shown in Figure 6a. The blending skid from a similar project is shown in Figure 6b and 6c for reference of size. Preliminary footprint dimensions of the blending skid are 3m (L) x 1m (W) x 1.5m (H).

Piping from the H2 supply will need to be routed underground to prevent congestion of the walkway beside the exhaust stack.

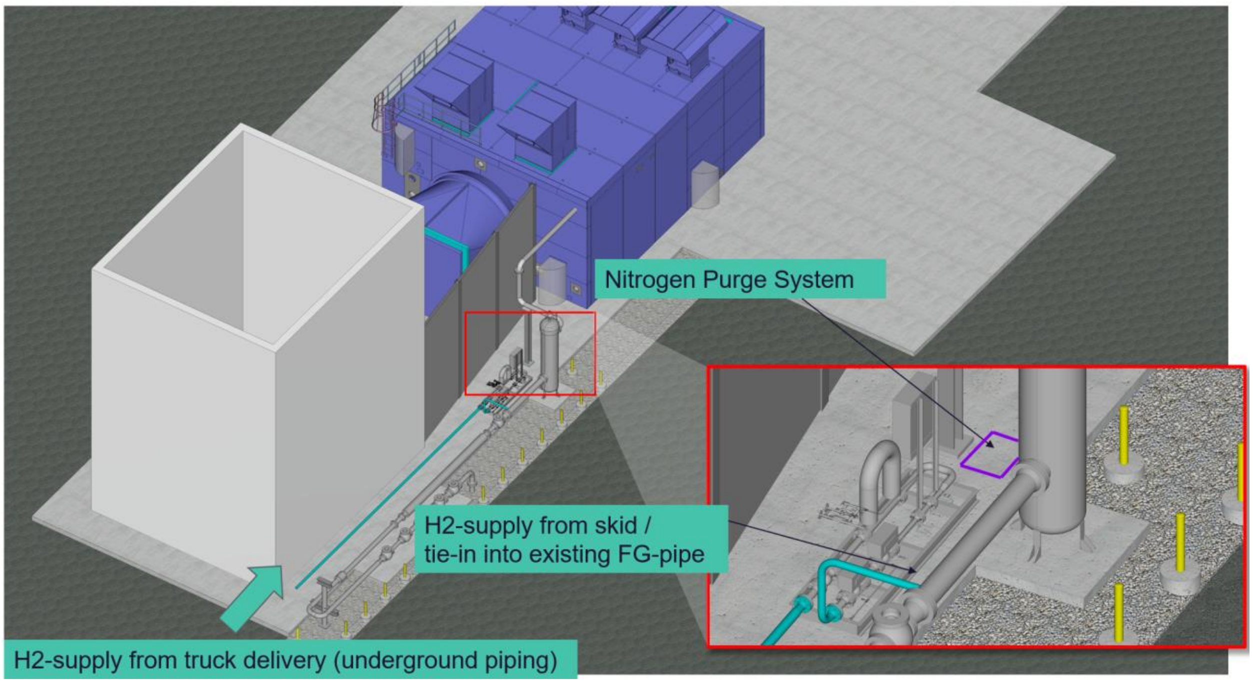

Fig 6a: H2 blending skid and FG tie-in locations

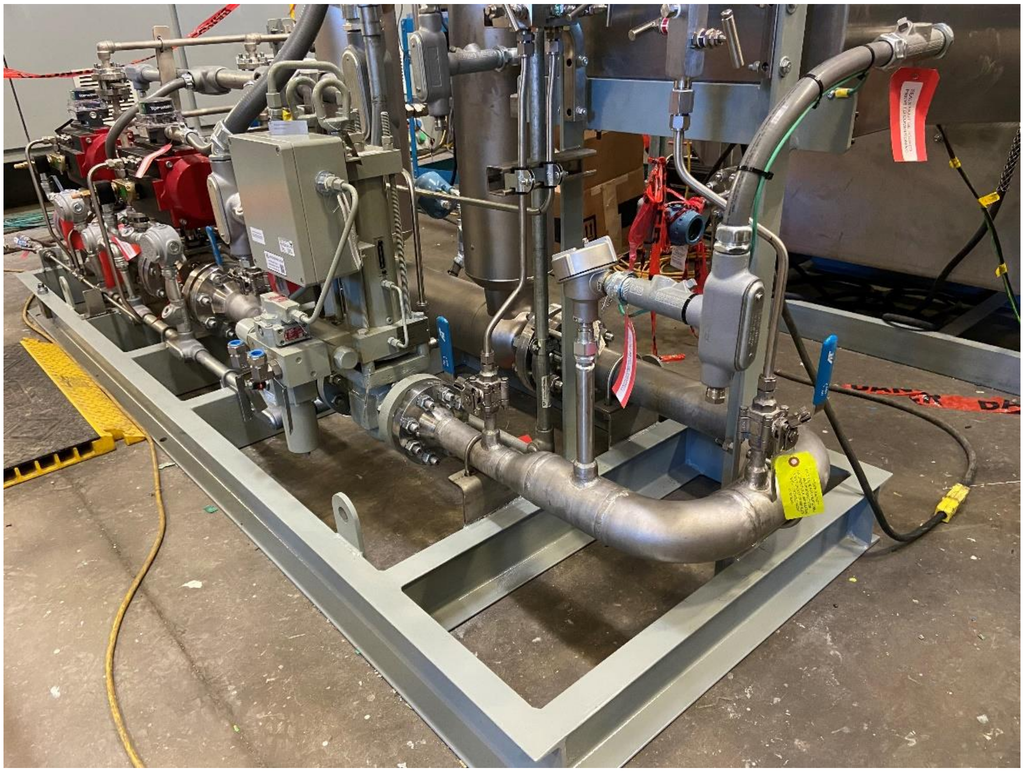

Fig 6b: H2 blending skid – manufactured for a similar project

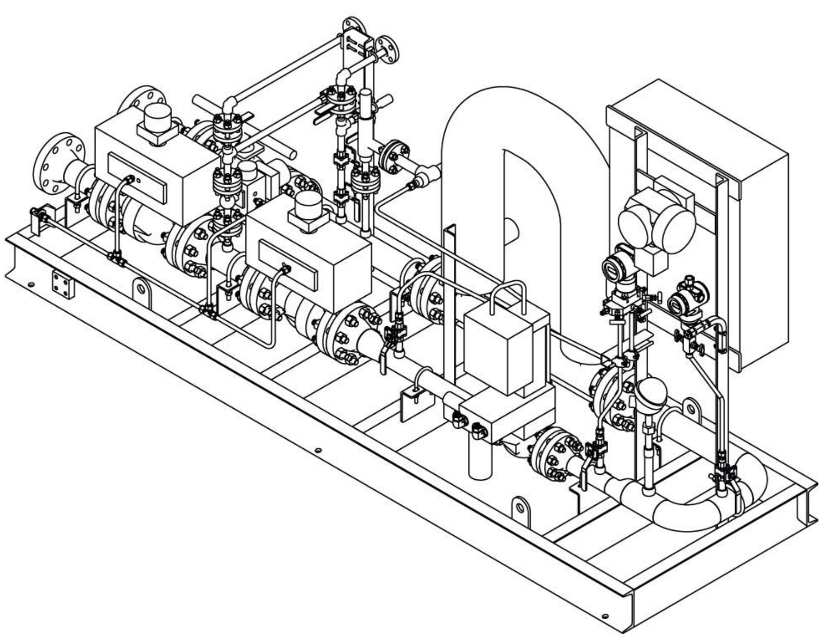

Fig 6c: H2 blending skid – isometric view

A nitrogen purge system is required to purge out all air before adding H_2 to the H_2 supply pipe and blending skid. N_2 purge is also required when purging H_2 from the piping, such as before an extended period before an outage or between H_2 re-supply shipments. It is a manual system with gas bottle rack and hoses to be connected to the manual purge valves at skid and supply line.

4.8. Fire and Explosion Protection with Hydrogen Co-Firing

In general, the fire and explosion concepts for natural gas and Hydrogen are similar. However, NFPA and the National Electric Code NEC distinguish between two protection classes for Methane and Hydrogen:

Methane: Class I Division II Group D

Hydrogen: Class I Division II Group B

It is required to address the additional, highly volatile, and explosive gas Hydrogen with measures including, but not limited to, good ventilation and well-placed Hydrogen sensors so that Hydrogen leaks can be detected and to include these measures into an upgrade of the plant fire and explosion protection system.

The explosion protection and hydrogen exclusion zones are illustrated in Fig 7, 8 and 9. A minimum 50 foot / 15 meter radius hydrogen exclusion zone around the GT air-intake is required to protect against H_2 leakage into the GT intake pathway and compressor. A 15 foot / 4.5 meter radius explosion protection zone is required around the H_2 blending skid and tie-in to the FG system.

Any instrumentation around the H_2 blending skid within the 15 foot / 4.5 meter radius will require a Class I Division II Group B rating.

Additionally, it is recommended to seal the acoustic wall located between the H_2 blending skid and the exhaust ductwork of the GT. A potential solution to making this wall gas-tight is to seal with caulking, to minimize H_2 leakage into the area behind the wall next the exhaust ductwork. Siemens Energy noted during the walk-down of the site that it is not feasible to completely seal this acoustic wall, as there are large gaps around the sides and bottom of the wall.

Therefore, any attempt to seal the wall should be considered best effort; instrumentation within the explosion protection zone must still be reviewed for suitability. Instrumentation outside of Siemens Energy scope of supply will need to be checked in this area and was not evaluated as part of the feasibility study.

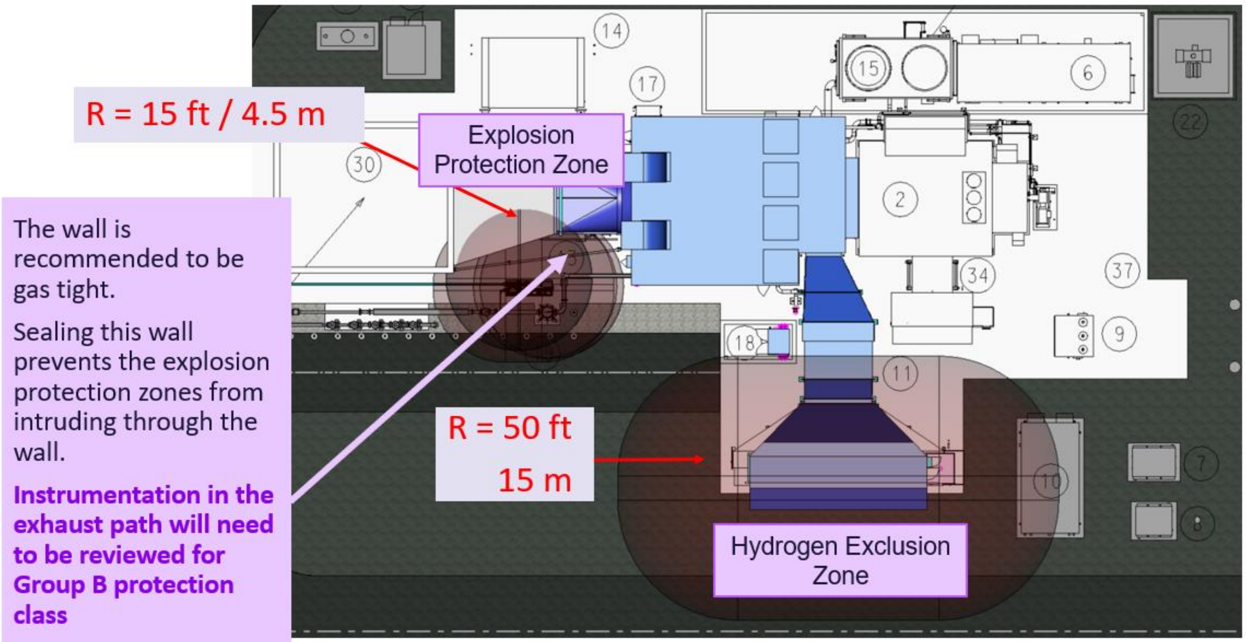

Fig. 7: Explosion protection zones – aerial view

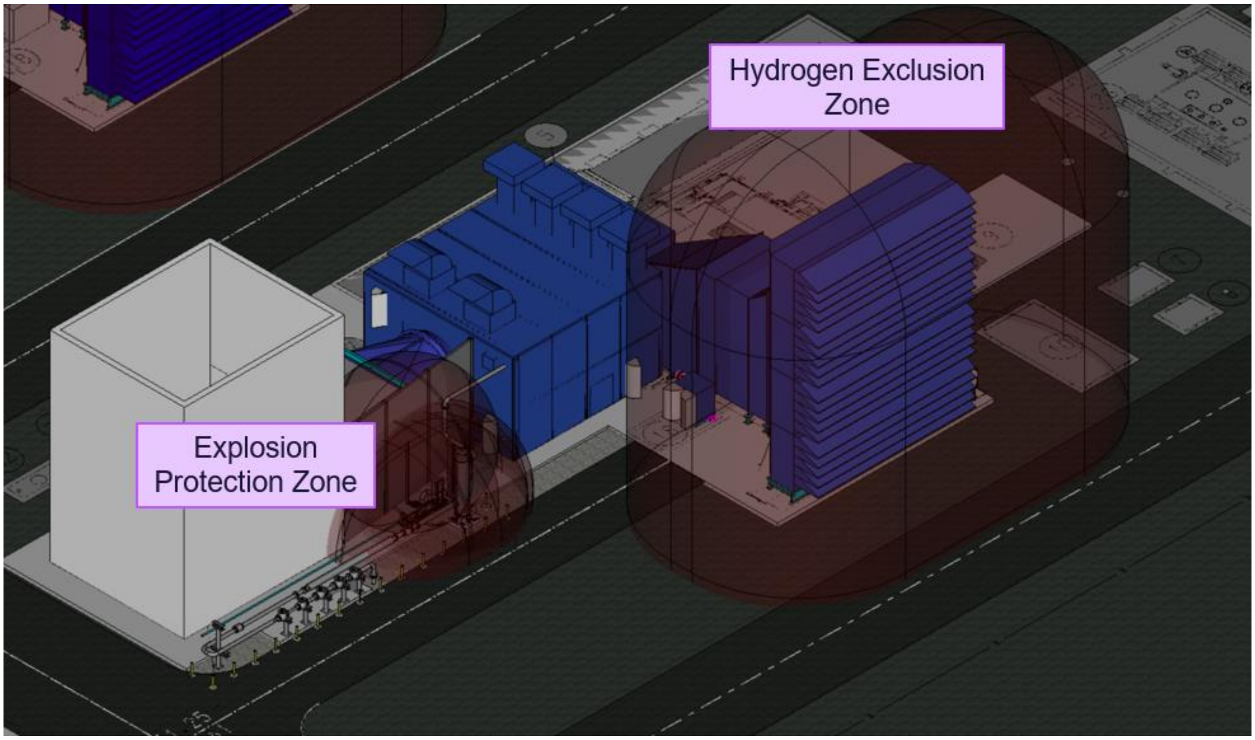

Fig. 8: Explosion protection zones – isometric view

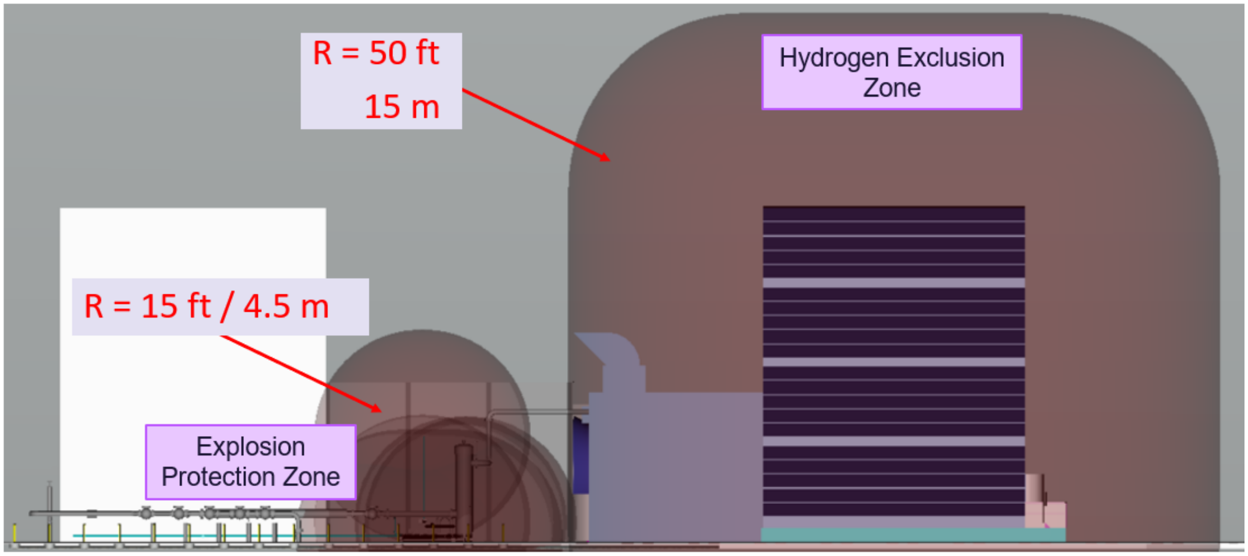

Fig. 9: Explosion protection zones – longitudinal view

4.9. Hydrogen Consumption

The consumption of Hydrogen depends on the load schedule and the degree of intended CO_2 reduction. This reduction stipulates the required co-firing rate for green Hydrogen.

On the matter of Hydrogen supply capacity, it is recommended to check available truck capacities with local Hydrogen suppliers. Five to six trucks were assumed as part of the general arrangement concept.

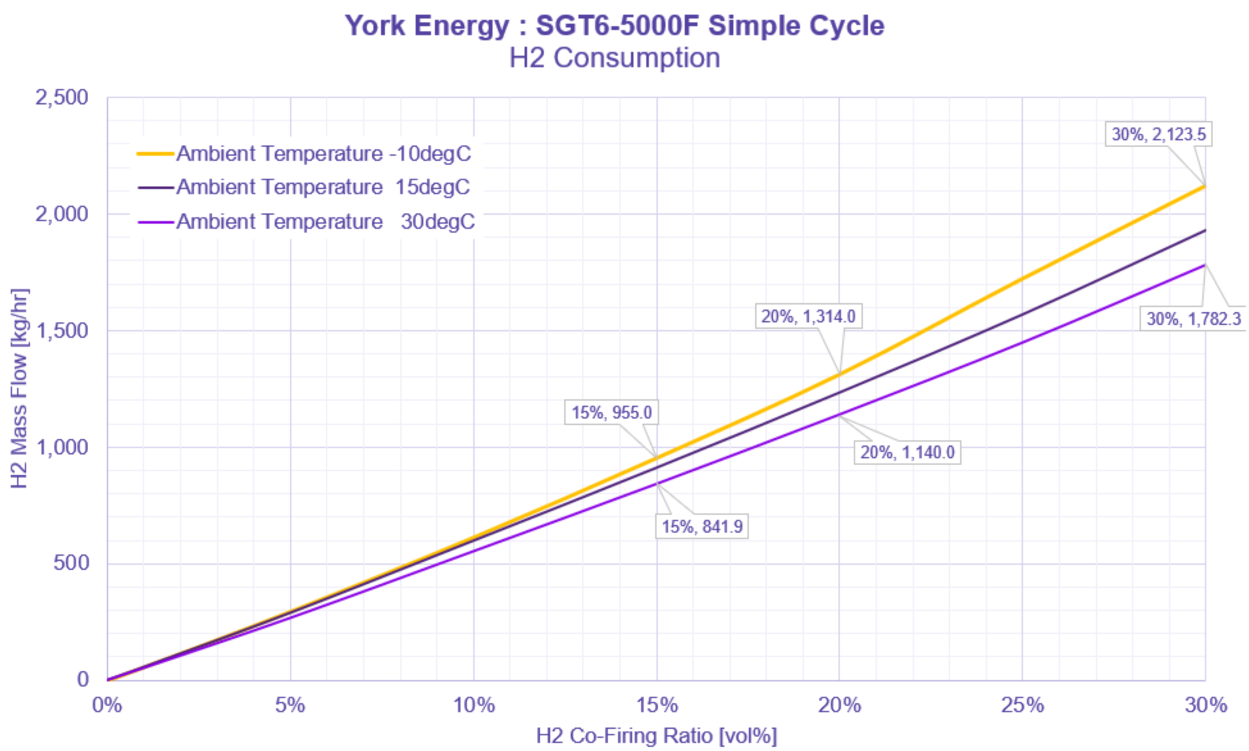

Fig. 10: Overview of Hydrogen Supply Requirements

4.10. General Arrangement

The proposed general arrangement is shown below in Figure 18 and 19. The proposed area for H2 supply trucks and pressure reduction station is located on the south side of the plant, between the underground septic and overhead transmission lines. A round-about loop is recommended to allow for ease of truck traffic and minimize turning within the plant.

A pathway through the existing parking lot for the power plant administrative and control buildings was reviewed at the site walkdown and deemed unfeasible. The most feasible route for H2 supply trucks using existing roadways is illustrated in Figure 11. This subject will require further review from the customer in future stages of the project. A dedicated route independent of the existing roadways is recommended and would require new construction.

Per OSHA 1910.103 no part of a hydrogen system that utilizes mobile trailers may be placed under overhead electric power lines. The general arrangement concept considered as part of this feasibility study shows that the Hydrogen pressure reduction station and mobile Hydrogen supply trucks can be placed in an area away from the overhead transmission lines and substation. The exact routing of trucks relative to the overhead lines needs to be considered in a future phase of the project.

Piping is routed underground to each of the GTs and connected to the H2 blending skid.

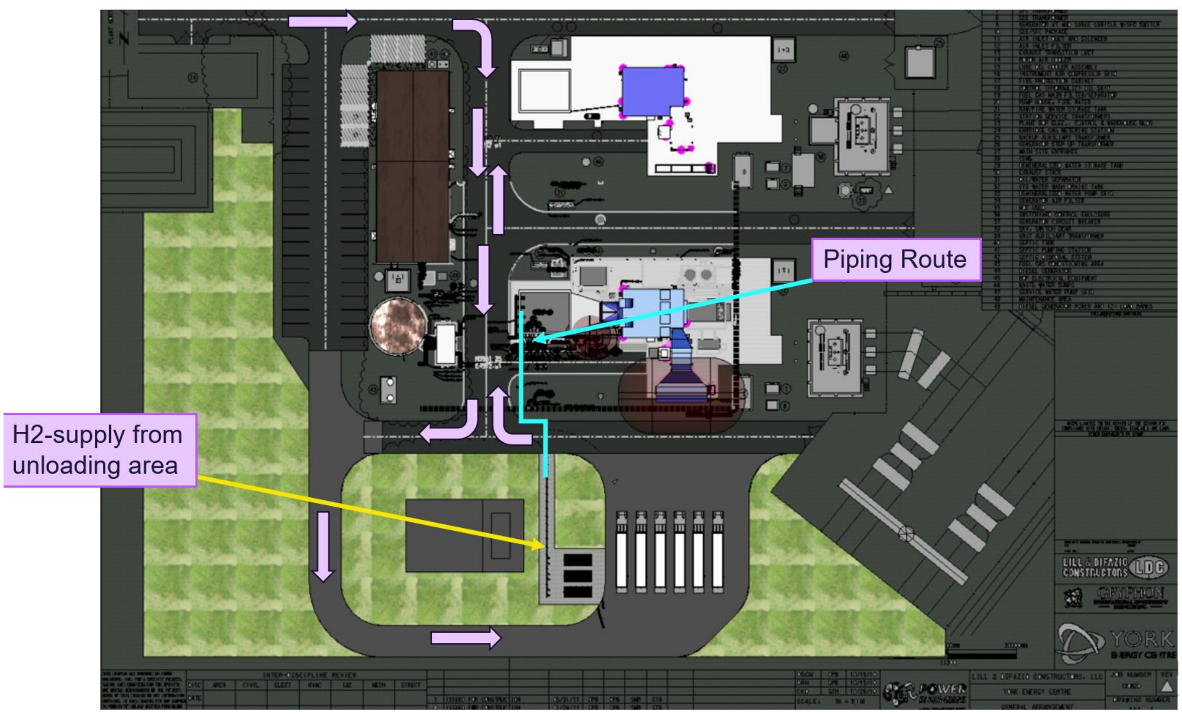

Fig 11: General arrangement of PP and Hydrogen supply and pressure reduction station

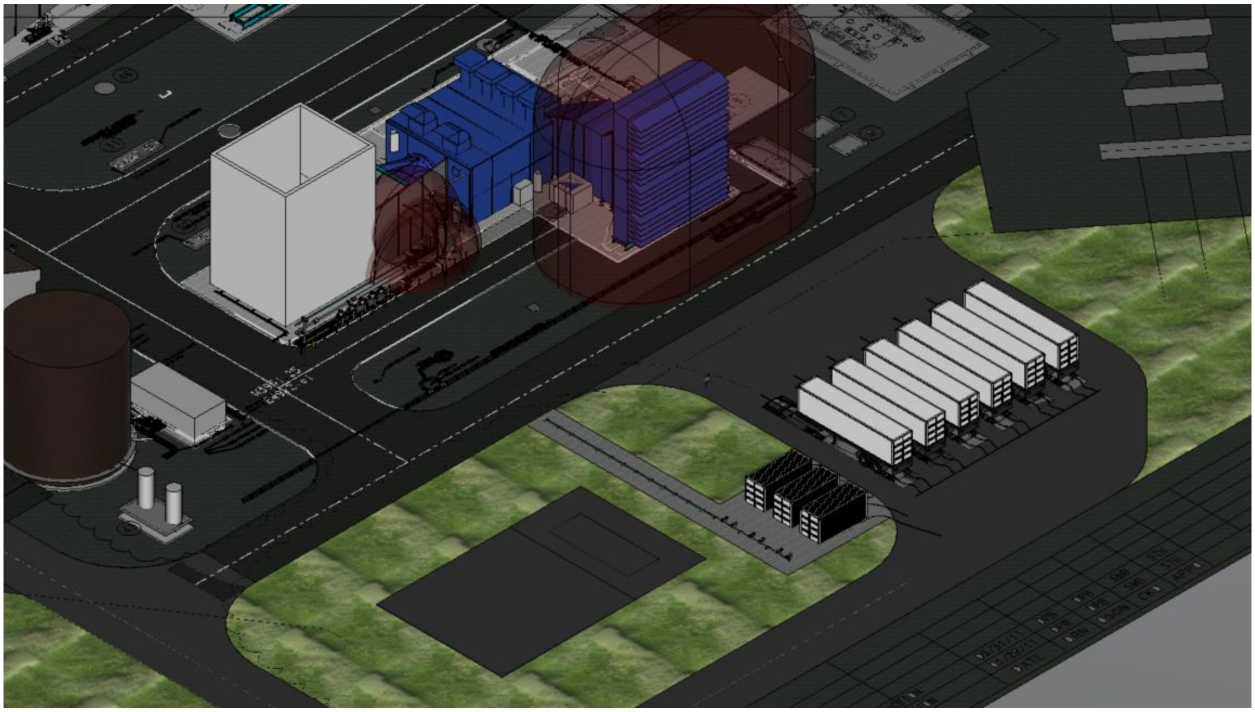

Fig 12: Hydrogen supply and pressure reduction station

Piping is routed underground to each of the GTs and connected to the H2 blending skid. The proposed lay-down for the H2 blending skid is shown in Figure 6a. The connection point to the existing FG system is also illustrated here.