Advancing turbomachinery innovations and strategies for net-zero pathways

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HRSG design for flexibility – Switch-over at full load from simple cycle to combined cycle operation for F-class Gas Turbines

Paper ID Number: 28-IGTC25

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Abstract

With the growing share of fluctuating renewable energy sources such as wind and solar, conventional power plants are increasingly expected to run in cycling operation mode. Due to the increased demand for flexibility from power plants, simple cycle (SC) and combined cycle (CC) plants are being designed for fast load ramps, shorter start-up and shutdown times, and a higher number of starts and stops. Consequently, the HRSG must also be designed for increased flexibility with an acceptable impact on the lifetime of components. A CCGT plant with a bypass stack and a diverter damper provides the plant operator with the option to startup and operate the plant over the bypass stack in SC mode or over the HRSG in CC mode. Conventionally, large gas turbines such as the F-class are required to ramp down in GT load before switching over from a SC to CC operation. Such a procedure is necessary to protect the HRSG from very high temperature transients, to minimise low cycle fatigue in thick-walled components such as the HP superheater headers, main steam line and the HP drum and to limit expansion differences. High temperature transients also increase the risk of magnetite cracking in the HP drum, inducing growth of cracks in the drum wall. For a cold HRSG start, switch-over from SC (at base load) operation to CC operation could take approximately an hour. In this new design, a switch-over from SC to CC at 100% GT load was investigated for a F-class GT. The considered HRSG design is a 3-pressure + reheat system equipped with the NEM - patented DrumPlusTM technology. The latest DrumPlusTM design has been optimized for lower wall thickness and has demonstrated the capability to support unrestricted GT ramp-up. The results of the design for the SC to CC switch-over at full GT load, dealing with specific aspects such as row and bundle expansion and impact on fatigue sensitive critical components are presented. Next to an optimised design, an optimized startup procedure was set up as well, finally enabling the HRSG to handle a switch-over at full load. The increased operation flexibility of the DrumPlusTM design is a valuable benefit to plant operators that need their plant to respond fast to maintain grid stability and increase plant efficiency by switching from a simple cycle to combined cycle operation.

Techno-economic Investigation of solutions for decarbonising the thermal management of the stand-still state of combined cycles

Paper ID Number: 43-IGTC25

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Abstract

In today's RES-driven energy landscape, flexibility of Combined Cycle Gas Turbine (CCGT) power plants is essential for integrating more non-dispatchable sources while ensuring reliable power supply. CCGTs must adapt their market role and adopt new, flexible, yet cost-effective operational practices, even during part-load phases, with a focus on reducing emissions but augmenting the grid service potential. A key area of improvement is reducing start-up time and energy use by optimizing asset thermal management during stand-still periods. In particular, maintaining temperature in bottoming cycle components without relying heavily on gas-fired auxiliary boilers is crucial. Techniques like electric heat tracing or steam sparging are known but evaluated more on time reduction impact than on operative consumption. Their integration with decarbonization and electrification solutions, such as high-temperature heat pumps, and waste heat recovery, warrants further exploration. This paper analyses typical Start-Up types to determine which low-carbon technologies are most promising under different operating and market conditions. It considers technological constraints, energy efficiency indicators, emission reductions, and economic factors—particularly the potential to leverage low-cost electricity during downtime.

Hydrogen blending and partial load control modelling: updated designs and simulations

Paper ID Number: 50-IGTC25

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As discussed in Harper et al. [1], EPRI has been investigating potential issues in real gas turbine hydrogen blending and flexible load control. Earlier research and operations have shown that gas turbines operating under variable partial load may experience more operational issues. This is partly due to the demands placed on the control system by a gas turbine operating at highly variable efficiencies and load. Demonstrations of hydrogen blending have been conducted on many gas turbines [2-6]. However, these demonstrations have generally not been completed under "real world" flexible loading operations of a gas turbine. It is highly likely that if hydrogen is utilized in large capacities in gas turbines in the future, it will be under variable and highly flexible loading operations due to the costs of hydrogen and the prevalence of Variable Renewable Energy (VRE, Solar, Wind) in that potential future scenario. As detailed in Harper et al. [1], without hydrogen, gas turbine peaker operation can be highly variable with many starts and load changes in short periods of time. The initial study found that traditional load control techniques may lead to operational issues in meeting grid demands and gas turbine operational requirements for robust operation when hydrogen blending is added. This work expands on the previous study of Harper et. al [1] by examining additional scenarios. The gas turbine model and control system have been updated to reflect the timescales of state changes (pressure, temperature, and power) more accurately with changes in boundary conditions (fuel/air flow). This is combined with an evaluation of an updated Model Predictive Control (MPC) architecture designed to control the blending rate, load, and combustion firing temperature accurately. These system design changes are detailed along with simulation results.

Technical session 2: Hydrogen combustion - impact on performance, safety and emissions

Experimental and numerical investigation of hydrogen injection, spontaneous ignition and flame stabilisation in a lab-scale sequential combustor at high pressure

Paper ID Number: 18-IGTC25

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Abstract

Sequential combustion staging has emerged as a well-suited approach for burning hydrogen in gas turbines, while maintaining low emissions and high cycle efficiency. A characteristic feature of sequential combustion systems is the high inlet temperature and the balance of flame propagation versus spontaneous ignition controlling flame stabilization in the second combustor stage. For the development of gas turbine combustion systems, able to operate on carbon-free fuels, it is important that experimental data at relevant conditions is available and that turbulent combustion models can accurately predict flame stabilization in the highly turbulent reacting flow. To match the propagation-to-auto-ignition balance, which is controlling flame stabilization, experimental validation of numerical models plays a key role in combustion systems development. Experimental results of N2-diluted hydrogen and pure hydrogen flames serve as a validation basis of Large-Eddy Simulations. Two flame stabilization configurations are investigated featuring significant differences in the steady-state flame location. Flame stabilization occurs in the combustor or directly at the fuel injection nozzle. The numerical model tested is able to capture the main flame-stabilization location observed in the experiments, while it is unclear whether the model correctly captures the occurrence of intermittent small ignition kernels in the mixing section

Retrofitting of an industrial DLN gas turbine combustor for fuel-flexible hydrogen applications

Paper ID Number: 52-IGTC25

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The use of lean-premixed combustion systems in gas turbines for power generation represents one of the most effective options to achieve low NOx emissions under dry conditions. Modern swirl burners can guarantee very low emissions and stable operation when traditional fuels (i.e., methane or natural gas) are used. However, these systems could be affected by flashback and could generate an increase in NOx emissions when they are fed with hydrogen blends. Considering the complexity of these systems and the fact that they are operated close to harmful conditions, it is necessary to schedule a periodic maintenance of the combustor and replacement of the injection system, implying maintenance costs, power plant shutdown, and environmental impact. This work follows a series of already performed studies on the injection system and the combustion chamber for a 5 MW machine. Both the available dataset obtained from reactive numerical simulations and the observations in the grade of deterioration registered during the maintenance phase are used as retrofitting guidelines for the definition of an innovative design of the injector/combustor geometries. The activity aims at having a significant impact on the turbomachinery sector through collaboration with EthosEnergy Italia S.p.a., an international company leader in gas turbine service and retrofitting. The newly designed configuration is numerically tested both at natural gas Base Load conditions and in the case of hydrogen blends, thus guaranteeing both stability at different fuel compositions and the extension of the service intervals for the upgraded design and increasing the scientific knowledge about hydrogen combustion in gas turbines.

Experimental investigation of minimum achievable NOx from low carbon fuels

Paper ID Number: 39-IGTC25

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Abstract

Low carbon fuels face growing interest as the power generation and transportation fields embrace decarbonisation. However, low carbon fuels may still introduce pollutant emissions challenges. Hydrogen and ammonia are two popular decarbonization fuels that face public scrutiny over potential NOx emissions. However, much of this scrutiny is grounded in unscientific roots, including experiments with improper control parameters or demonstrations with legacy hardware that are not appropriate comparison tests for these fuels. Therefore, EPRI and the Zinn Combustion Lab at Georgia Tech have conducted a series of chemical kinetic simulations and experiments with both hydrogen and ammonia to examine NOx emissions from direct combustion of these fuels with a target of dry, low NOx comparisons. The calculations were conducted to determine burner architectures that promise low NOx potential and fuel flexibility, as well as to predict the minimum achievable NOx (NOx entitlement). The experiments were conducted to validate the calculations and to provide first-ever demonstrations of a new fuel flexible, low NOx burner concept designed for these decarbonization fuels. This paper will present the promising calculations and experimental results. The results show hydrogen NOx emissions similar to natural gas combustion, and low double digit NOx concentrations from direct ammonia combustion.

Technical session 3: Alternative fuels-powered turbines - solutions for decarbonisation

Enabling rapid decarbonisation of gas turbine power generation with hydrotreated vegetable oil

Paper ID Number: 36-IGTC25

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Abstract

Hydrotreated vegetable oil (HVO) produced from waste feedstocks offers significant lifecycle CO2 emissions reduction when used in applications consistent with the European Union's Renewable Energy Directive (RED). Given its similarity to fossil diesel, HVO has been demonstrated in power generation gas turbine (GT) trials as a suitable drop-in replacement fuel. Uniper successfully completed the world's first GT HVO trial in July 2021 and subsequent trials in Germany, the United Kingdom, and Sweden. The most recent trial was conducted on an FT4 aeroderivative GT at Barsebäcksverket (BVT) in June 2024. Additionally, Uniper has converted GT units in Sweden to use HVO. However, long-term operational evidence remains limited. This paper presents an overview of HVO activities using power generation GTs. The carbon intensity and greenhouse gas emissions of HVO for power generation are discussed in line with the RED requirements. Uniper's HVO trial at BVT and experience with HVO GT conversions are described, including performance and emissions results. The development needs and sustainability requirements are discussed to enable further expansion of HVO in power generation. HVO enables a rapid reduction in lifecycle CO2 emissions and delivers low-carbon, dispatchable GT capacity to complement variable renewable energy sources and provide critical grid services.

Demonstration of methanol as a sustainable fuel for gas turbines: emission reductions and performance enhancements

Paper ID Number: 24-IGTC25

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Abstract

Transitioning to net-zero necessitates innovative approaches to reduce emissions and enhance gas turbine performance. This paper reports three methanol demonstrations on Siemens Energy's SGT-A05, SGT-A20, and SGT-A35 engines. Test objectives included quantifying emissions, power, and efficiency changes and proving fuel system and combustor upgrade methodologies. The SGT-A20 test validated the design methodologies and upgrades, including the increased fuel system capacity, methanol capable fire and gas detection systems, and modified fuel injectors. The SGT-A35 test scaled the approach to higher power output and turbine temperatures in the same facility, while additive manufacturing accelerated prototyping and final hardware delivery. The SGT-A05 ran in a production genset on 100% methanol (M100) and an 80% - 20% methanol-water blend (M80) which targeted further NOx reduction, proving methanol's ability as a diesel alternative. Following minor control changes to address methanol's low volumetric heating value, all engines executed starts, shutdowns, and fast transients fault-free. Results were consistent across tests: at constant power NOx reduced ~80% on M100 and ~90% on M80, and carbon dioxide was ~10% lower than kerosene baselines. These findings demonstrate methanol's viability as a sustainable gas turbine fuel and provide actionable design, test, and operational guidance to accelerate deployment in support of the energy transition.

Use of methanol as a potential alternative fuel in a power generation gas turbine

Paper ID Number: BP2-IGTC25

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Abstract

Decarbonisation and emissions reduction have become major priorities in industrial power generation. Achieving net-zero greenhouse gas emissions requires adopting alternative fuels such as ammonia, hydrogen, and alcohols, with methanol emerging as a promising candidate. This study investigates the feasibility of using methanol in the SGT5-2000E gas turbine at Killingholme Power Station by modelling the combustion performance of a Siemens Energy Dry Low NOx (DLN) Hybrid Burner, capable of liquid and gaseous fuel operation. A dual-phase strategy is proposed: initial liquid methanol firing to generate sufficient heat for a Waste Heat Recovery (WHR) system, followed by a transition to evaporated methanol. This approach could reduce fuel consumption by 5–6% and reduce NOx emissions. Chemical kinetics modelling of evaporated methanol combustion showed a potential 10% NOx reduction compared to methane, alongside challenges such as increased flashback risk and higher autoignition potential. A key challenge was the increased fuel injection pressure drop due to methanol’s higher mass flow. A RANS (Reynolds-Average Navier-Stokes) CFD (Computational Fluid Dynamics) model was developed, showing that non-uniform nozzle modifications most effectively improved mixing, lowered peak flame temperatures, reduced flashback risk, and significantly decreased NOx emissions. The results highlight the potential for retrofitting turbines for low-carbon bio- and e-methanol combustion, supporting greener energy solutions and longer turbine life. The methanol dual-phase concept shows strong promise for further development.

Technical session 4: Enabling next-gen turbomachinery - advanced techniques for component design

Bulk hydrogen production and the impact on turbomachinery lifing

Paper ID Number: 46-IGTC25

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Abstract

The EU has made the commitment to achieve climate neutrality by 2050 and reduce pollutant gases emission by 2030. To achieve these targets the power generation sector must engage. Gas turbines will play a part through the use of alternative fuels such as H_2. However the adoption of H_2 as a fuel presents multiple engineering challenges, from flame stability, to NOx emissions, to materials' degradation. The latter is inherently linked to the technologies used to produce hydrogen in the bulk quantities required. Different technologies will generate H_2 with different purity levels, as well as different quantities and types of contaminants (i.e., Cl-based for seawater electrolysis, S-based from steam methane reforming). This is important as, upon combustion, these contaminants can form harmful species in the exhaust stream, linked to mechanisms causing materials degradation. It is therefore crucial to understand the types of contaminants that are present in bulk H_2 and so in the combusted gases. This work links together fuel and ingested air chemistry in the gas turbines to the chemical composition of the combusted gases, to the degradation mechanism that might arise in blading materials, finally and their impact on the gas turbine life. Exhaust gas composition has been predicted via thermodynamic modelling, and the condensation of harmful species that will ultimately dictate the corrosion mechanisms (e.g., alkali vapour) calculated.

Gas turbines performance improvement enabled by additive manufacturing

Paper ID Number: 4-IGTC25

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Abstract

To drive emissions reduction and performance improvement of the gas turbines, Siemens Energy is working continuously with the development and implementation of new advanced technologies. This paper describes the integration of groundbreaking additive manufacturing (AM) technology into the design and manufacturing of gas turbine components. Siemens Energy is already implemented AM technology in the design and manufacturing of combustor components to run gas turbines on green fuels. As an example, the implementation of AM burners in medium-size gas turbines (MTG) with Dry Low Emission (DLE) combustors expands their fuel flexibility and ability to run on hydrogen-rich gases. Today, the SGT-600, -700 and -800 can be offered to run on fuel with up to 75 vol% H_2 in the fuel. Integrating AM technology into the design and manufacturing of turbine's components, such as vanes and blades, leads to substantial improvements in gas turbine efficiency and, as a result, gas turbine fuel consumption and emissions reduction. This paper describes the infusion of AM technology into the design and manufacturing of hot gas path components, in the turbine vanes of Siemens Energy gas turbines. Improving the efficiency of turbine and turbine components is driven by utilizing new advanced cooling systems and better aerodynamics enabled by the practically unlimited capability of AM design and manufacturing. Successful design, manufacturing and field validation of AM vanes in Siemens Energy SGT-700 gas turbine are presented and discussed in this paper. The reliable operation of AM components under real field operation conditions has been confirmed by the total accumulated field experience, which already exceeds 1,700,000 operating hours.

AM enabled injection systems for enhanced fuel flexibility

Paper ID Number: 57-IGTC25

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The demand for fuel-flexible combustion systems is rising with the transition to renewable energy vectors like hydrogen, ammonia, methanol, sustainable aviation fuel (SAF), and hydrogenated vegetable oils (HVO). High-momentum jet-stabilised combustion systems have shown significant benefits for hydrogen-based operation. However, achieving clean, fuel-flexible combustion imposes strict requirements on injection and mixture formation, especially as partially cracked ammonia can cause large variations in the Wobbe index, affecting fuel momentum and penetration depth. Decoupling mixture formation from fuel properties is key to ensuring homogeneous mixing before flame interaction. Additive manufacturing (AM) offers innovative solutions by enabling intricate fuel injection designs. This study explores AM-enabled space-filling injectors to enhance fuel flexibility, focusing on Powder Bed Fusion Laser Beam (PBF-LB/M) processes in In718 to create space-filling micro-structures with sub-100 µm feature sizes. The objectives are optimised fuel placement and mixture homogenisation while realising fuel jet injection momentum independence. Using schlieren imaging, the improved mixture formation with reduced Wobbe index sensitivity is demonstrated, enabling excellent multi-fuel adaptability. This research highlights AM's potential in developing cost-effective, multi-fuel injection systems for gas turbines, particularly in applications requiring co-firing and adaptability to regional or temporal availability fluctuations of sustainable carbon-free energy vectors.

Technical session 5: Progressing hydrogen-readiness - field experience

HYFLEXPOWER Project: power-to-H_2-to-power demonstration with 100% green hydrogen in an SGT-400 gas turbine

Paper ID Number: 40-IGTC25

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Abstract

Green hydrogen generation from renewable energy and combustion in gas turbines are expected to play a crucial role in to the decarbonization of power generation. The HYFLEXPOWER project is a pioneering initiative aimed at demonstrating the feasibility and benefits of integrating 100% green hydrogen as a flexible power source within existing energy systems. This paper summarizes the first successful development, installation, and demonstration of a power-to-H_2-to power pilot application at an existing cogeneration plant with a dry low emissions (DLE) Siemens Energy SGT-400 gas turbine in Saillat-surVienne, France. During two separate test campaigns, the modernized plant and the SGT-400 gas turbine were successfully operated with hydrogen blends ranging from 0% to 100% in natural gas. The development and upgrades of hydrogen combustion technology, the gas turbine, and the cogeneration plant are discussed. Gas turbine testing results from Siemens Energy's factory in Lincoln using natural gas and from the pilot demonstration plant in France using up to 100% H_2 for carbon-free power generation, are presented. Additionally, the paper analyses the techno-economic feasibility of green hydrogen production, storage and utilisation in the cogeneration plant, via the development of an optimisation tool. The optimisation tool was applied in a case study involving the commercial operation of the SGT-400 gas turbine on 100% H_2 vol, aiming to determine the optimal sizing and dispatch of the power-to- H_2 energy system components.

Cofiring 45% H_2 in F-class gas turbine: looking beyond the GT

Paper ID Number: 20-IGTC25

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Abstract

Today, gas fired assets are an ideal companion for our renewable assets, being dispatched in a flexible way to ensure the grid stability. The EU came with taxonomy categorising power plants based on their CO_2 emissions, and thus their risk of harming reaching the Paris agreement goals. Within the ENGIE fleet, the GT26 units could achieve, with the latest engine upgrades and hydrogen cofiring, the threshold value of 270 g CO_2/kWh, where these are considered not doing any harm to reach the goals. Based on an existing power plant configuration, ENGIE has conducted a feasibility study to explore the technical possibilities and on-site modifications to reach 45 vol% hydrogen cofiring on the GT26 gas turbine. Several challenges were identified, such as the risk of flashback, higher NOx emissions, and fuel gas compressor selection for the hydrogen preparation.

Hydrogen gas turbine (H_2GT) demonstration in South Korea

Paper ID Number: 48-IGTC25

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Abstract

Energy chemical storage in the form of (Carbon-free) Hydrogen is at the forefront of research in the industry. Hydrogen flames are very stable but known for producing higher NOx vs Natural Gas. Advanced Hydrogen premix combustors are being developed, but major challenges are faced, with flashback avoidance being the major issue. PSM's FlameSheet™ proved, in rig tests, to be able to burn large quantities of Hydrogen. PSM, Thomassen, Hanwha joined forces to move, convert and commission a 7EA capable of burning over 50%vol H_2. At a petro-chemical plant in Korea, off-gas containing 40%vol H_2 was used, together with pure H_2, and LNG for start-up. A mixing station combined and precisely controlled the level of H_2 fueling the engine. This paper highlights the challenges faced and solutions devised for the combustor, the fuel delivery system and the control sequences, all key elements to success. Safety was another important aspect and key principles are described. After months of efforts, the GT achieved full load on April 14th,2023. An official governmental measurement of 59.5%vol H_2 and single digit NOx was demonstrated. Full Hydrogen capability (100%vol H_2) and single digit NOx was demonstrated at Full Speed No Load (FSNL) on November 1st, 2023.

RWE light house project case study: Moerdijk high hydrogen conversion

Paper ID Number: 45-IGTC25

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Abstract

Hydrogen is considered a key technological solution to decarbonise many heavy industries, including in the power sector to fuel Gas turbines (GT). Typically, GTs operate on carbonaceous fuels such as natural gas, which produce CO_2 emissions. To avoid further emission of CO_2 into the atmosphere and avoid stranded assets, conversion of in-the-field assets is a key aspect for the low-cost attainment of lowcarbon operation. This paper highlights the feasibility work on-going at RWE's Moerdijk GE Vernova 9F.04 (9F.02) F-class 420 Mwe CCGT Power Station, located in the Netherlands. It presents a case study of the hydrogen conversion to 80+ vol-% outlining the technical, operational and environmental considerations involved. This study outlines the fuel supply chain integration undertaken to ensure a secure supply of hydrogen can be delivered to site through either leveraging existing or new infrastructure and an overview of the technical developments to convert the asset (GE 9F.04) to operate on hydrogen containing fuels, involving retrofitting with the latest OEM combustion technology. An overview of the lifecycle emissions reduction and operational cost implications are also included.

Technical session 6: Advancing CO_2 technologies - capture and storage technologies, and power cycles

Experimental impact of exhaust gas recirculation and hydrogen injection on the emissions and performances of a micro gas turbine

Paper ID Number: 34-IGTC25

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Abstract

To achieve a zero-carbon economy with gas turbines, amine-based carbon capture has emerged as a potential solution, though it comes with a significant energy cost. Exhaust gas recirculation (EGR) is therefore used to mitigate the efficiency penalty associated with carbon capture by increasing the CO_2 concentration in exhaust gases and reducing the overall gas mass flow. However, operating near stoichiometric combustion conditions elevates CO emissions, thereby limiting the feasible EGR rate. Hydrogen cofiring has been proposed as a promising approach to stabilise combustion under these conditions, where the air-fuel ratio approaches unity. Despite its potential, the impact of hydrogen cofiring on performance and emissions remains largely unexplored. To address this gap, experiments are carried out using a 3 kWe micro gas turbine (MTT EnerTwin ®) fuelled with methane blend containing 20% hydrogen. This study examines the effects on emissions, including CO_2, O_2, NOx and CO. The modified setup, which supports higher EGR rates, provides valuable insights into how hydrogen cofiring can stabilise combustion and enhance carbon capture efficiency. These findings are crucial for scaling the behaviour of micro gas turbines to industrial applications and assessing the combined potentials of EGR and hydrogen to minimise the energy penalty of carbon capture technologies.

Optimisation of CO_2 capture from natural gas combined cycle with hydrogen-assisted exhaust gas recirculation

Paper ID Number: 33-IGTC25

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Abstract

CO_2 capture and storage (CCS) is crucial for reducing emissions in areas with limited renewable energy or to balance their intermittent nature. CCS, however, reduces the efficiency of gas turbine combined cycles due to the high air-to-fuel ratio, resulting in low CO_2 concentration in exhaust gases. Exhaust Gas Recirculation (EGR) can increase CO_2 levels but is limited to about 35% due to combustion stability issues. The EU project TRANSITION explores using hydrogen to pilot burners, allowing higher EGR rates without compromising combustion stability. Experimental data on emissions and Lean Blowout resistance were used to model the impact of hydrogen-assisted EGR on CO_2 capture and overall efficiency. Results indicate that higher EGR rates reduce CO_2 capture energy requirements and equipment sizes, with minimal additional energy costs for EGR systems. The study aims to optimise hydrogen use for maximum efficiency gains while considering costs, safety, and auxiliary energy use. Additionally, the integration of hydrogen-assisted EGR shows promise in enhancing the overall performance of gas turbines, making them viable for lowcarbon power generation. This approach could significantly contribute to the energy transition by enabling more efficient and stable CCS in gas turbine systems.

Testing of the STEP 10 MWe sCO_2 power plant in simple recuperated cycle configuration and model comparisons

Paper ID Number: 14-IGTC25

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Abstract

The 10 MWe Supercritical Transformational Electric Power (STEP) Demo pilot plant has completed its first phase of testing and has achieved full operational speed of 27,000 rpm at a target turbine inlet temperature of 500°C in the Simple recuperated Cycle (SC) configuration. This milestone was achieved while synchronized with the electrical grid generating a gross turbine aerodynamic power of 8.3 MW (11,500 hp) and approximately 4 MWe of net power to the grid. This is the highest capacity to date in the world for indirect-fired sCO_2 power technology. This $170 million project is a partnership between GTI Energy, SwRI, GE Vernova, and the US DOE. Mechanical completion was achieved in October 2023. In May 2024, the plant ran and generated electricity for the first time. Subsequent testing continued leading to the maximum power in the SC configuration achieved in September 2024. The results of testing of the plant's major systems including the compressor and turbine machinery trains, the cooling tower system, the heater, inventory management system, and heat exchangers generally show performance in line with expectations and simulation modelling. The next phase of the project will transform the pilot from Simple Cycle to a Recompression Brayton Cycle (RCBC) configuration and operate up to 715°C. The modifications include adding a second compressor, a second recuperator, and a higher temperature turbine stop valve, which will improve thermal efficiency, increase mass flows and more than double the power output. This project is on-going and is making a significant contribution to the advancement of this promising power generation technology offering efficiency, cost, and emissions improvements over existing approaches.

Uncovering the economic tipping point between H_2-based gas turbines and CCS-enhanced gas turbines

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Abstract

In the pursuit of carbon neutrality, decarbonizing electricity production is a central yet complex challenge. While renewable sources like wind and solar are increasingly viable, their intermittency necessitates reliable and dispatchable alternatives. Gas turbines (GTs) can provide this flexibility, and two main pathways exist to make them carbon neutral: H_2-based GTs and CCS-enhanced GTs using amine- based carbon capture. Both options are compared technically and economically. It evaluates the feasibility of burning pure hydrogen and capturing 100 % CO_2, and examines their impact on efficiency, CAPEX, and OPEX. Simulations using Aspen Plus and economic modelling reveal that CCS-enhanced CCGTs, despite higher CAPEX, outperform H_2-based CCGTs due to currently prohibitive hydrogen costs. The study finds a LCOE of 140 €/MWh for CCS versus 1660 €/MWh for hydrogen, and payback of 23 years for CCS with EGR while no payback for hydrogen. A user-friendly online tool was also developed to assess scenarios based on real-world parameters. These findings underscore the current economic advantage of CCS-enhanced turbines, while highlighting the need for hydrogen cost reductions to make H_2-based systems viable.