Hydrogen Based Energy Storage System for Integration with Dispatchable Power Generator—Phase I Feasibility Study

Final Technical Report

Reporting Period: 3/1/2021—2/28/2022

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Date of Report: 5/30/2022

DOE Award #: DE-FE0032021

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ABSTRACT

This project examined the feasibility of integrating hydrogen generation, storage, and use as a means to decarbonize campus activities while retaining the ability to utilize the existing natural gas fired combined heat and power system installed at the campus of the University of California @ Irvine. Analysis of specific potential sites for the integrated system identified a location adjacent to the existing central plant which resulted in minimization of interconnections. A strategy based on use of commercial electrolyzers and gas storage was identified. Primary technology advancements are required for the gas turbine to accommodate higher levels of hydrogen and the integrated controls. The project indicated challenges for adopting the proposed strategy with the present rates and constraints. The availability of a relatively low-cost biogas resource by the campus already decarbonizes the gas turbine to some extent. In the absence of this resource, procurement of electricity directly from large scale renewable operations could facilitate lower electricity costs. Additional solar resources on campus could also help in this regard. The gas turbine cannot be operated below 50% capacity due to air permit constraints. Using the otherwise curtailed gas turbine operation to generate hydrogen via electrolysis by consuming natural gas is not highly efficient and therefore leads to relatively high costs of electricity returned. Several scenarios demonstrate potential for effective decarbonization, yet most involve lower and lower capacity factor for the legacy gas turbine which is not a good use of the asset. A small gas turbine output with higher efficiency operation would help. As would ability to export electricity to the grid. Certainly current rate structures and operational scenarios are less attractive than other possible future structures which should be pushed for in the future.

ACKNOWLEDGEMENTS

The support of Southern California Gas is greatly appreciated. The support of Jerry Nearhoof, Mike Bonomo, and Joe Fleshman of UCI Facilities is also acknowledged. Mike Ramotowski and Luke Cowell of Solar Turbines provided critical input on the project as well as the reporting and Appendices

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1 Introduction

This project addressed key aspects of the Funding Opportunity Announcement under Topic Area 1A. Namely, assessing feasibility of integrated energy storage technologies with an existing fossil fueled asset that will allow:

> *"increased flexibility of Electricity Generating Units to assure increased flexibility to assure short and long-term reliability in the delivery of electric power as the use of renewable power generation increases."*

And to advanced technologies to

> *"mitigate inefficient, off-design operation of the Electricity Generating Unit (e.g., frequent, deep cycling of units designed for baseload operations)" which results in negative impacts such as "decreased power efficiency, increased environmental impacts associated with some operations, equipment damage, accelerated equipment degradation, and increased operational costs"*

Given the situation at the UC Irvine campus, the target goal for the effort was to develop a design for a 10 MW-hr hydrogen-based energy storage system to be integrated with an existing fossil fueled gas turbine at the University of California, Irvine campus. The UCI central plant features a natural gas fired 13 MW gas turbine which is coupled with a heat exchanger that captures waste heat for use in either additional power generation via a steam turbine, chilling via an absorption chiller, or heating via steam use and exchange with a district heating system. The campus has recently installed over 4MW of photovoltaics (PV) panels. This has reduced the demand for the gas turbine generated electricity but has increased the need for dynamic operation of the gas turbine to address intermittency associated with the PV. Coupled with heating and chilling needs, the intermittency has 1) reduced overall efficiency of the power generation asset, 2) increased criteria pollutant and carbon emissions, and 3) increased wear and tear and associated maintenance. This project facilitated evaluation of adding energy storage in the form of hydrogen that will help address these operational issues and potentially provide economic benefits to the campus.

To illustrate the challenges of intermittent renewable power on the operation of the plant gas turbine, Figure 1 presents a plot of capacity factor for the UCI Gas Turbine using measured operational data during summer days from 11:00 am to 3:00 pm before and after an additional 3.5 MW of PV installed.[1] As shown, UCI's gas turbine operability is impacted as a direct result of the installation of intermittent renewable power and operates more of the time at part load than it did when only 0.9 MW of PV was installed. As a result, the site offers an opportunity to explore how increasing the usage through stored on site hydrogen might impact the overall operation of the system.

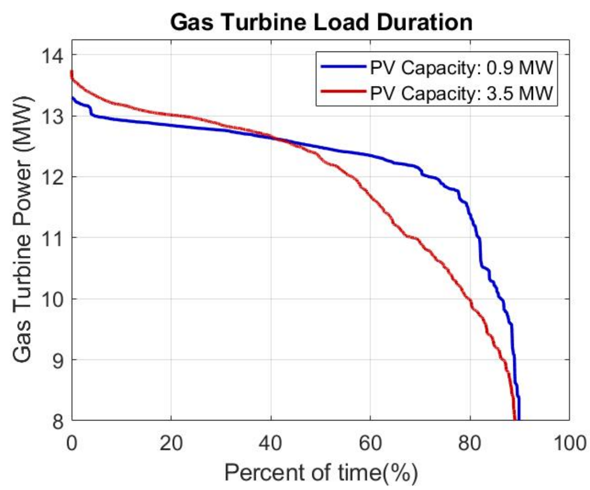

Figure 1. Actual Operational Data Illustrating Impact of Installed PV on Gas Turbine Operation Profile.

The project allowed UCI to evaluate the feasibility of adding electrolytic and/or other means of hydrogen production, along with hydrogen storage capacity, to serve both the campus microgrid and the nearby campus hydrogen refueling station (HRS). If implemented, the proposed design would establish the capability for the gas turbine to operate on high-hydrogen-fraction natural gas / hydrogen blends and to dynamically vary the hydrogen fraction to optimize economic and operational dispatch. The central plant gas turbine and heat recovery system will produce and store low-cost hydrogen electrolytically or thermally from either water or natural gas during times of low campus net load and will consume the stored hydrogen during times of high net load and low (or

[1] Flores, Robert, and Jack Brouwer. "Optimizing Natural Gas Combined Cycle Part Load Operation." *ASME Power Conference*. Vol. 59100. American Society of Mechanical Engineers, 2019

zero) PV production. This project aligns well with concepts for an overall hydrogen storage ecosystem on the campus which is illustrated in Figure 2.

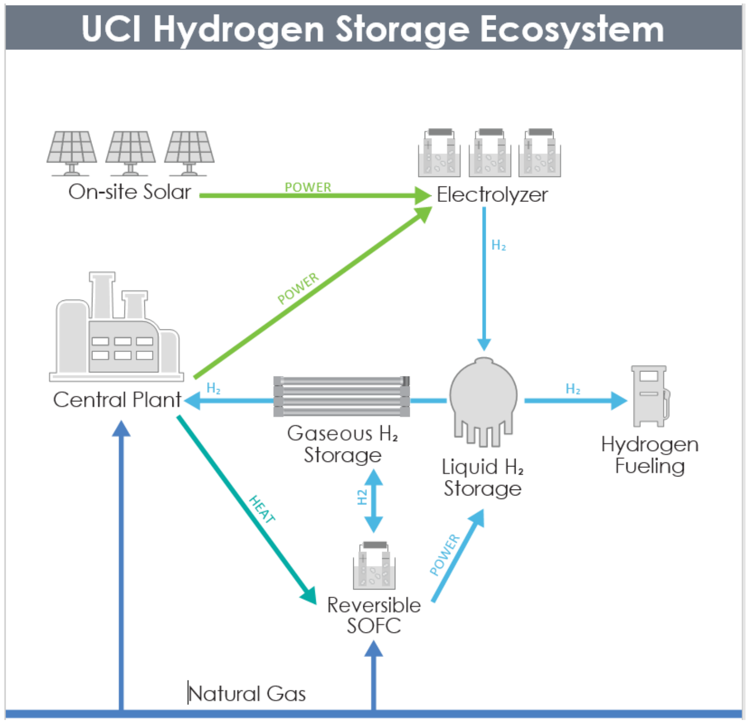

Figure 2. Conceptual UCI Hydrogen Storage Ecosystem.

Specific technical objectives of the system are to achieve a $150/MWh energy storage cost (cost of storage and reconversion to grid power) and a hydrogen cost of $2/kg. The system design will provide energy storage in the form of hydrogen capable of providing 10 MWh of returned energy. As part of the project, a technoeconomic study will be carried out to assess the generic implementation of the system proposed to assess overall value and pricing models. The work performed will set the stage for a PreFEED project plan for integration of an energy storage technology with an existing fossil fueled asset.

Figure 3 provides perspective relative to the overall project location and where existing and proposed assets are indicated. The Central Plant is where the existing natural gas fired gas turbine (Solar Turbine Titan-130) is located. Final recommendations for specific components and their physical location will be established as part of the Conceptual Study carried out in the proposed effort.

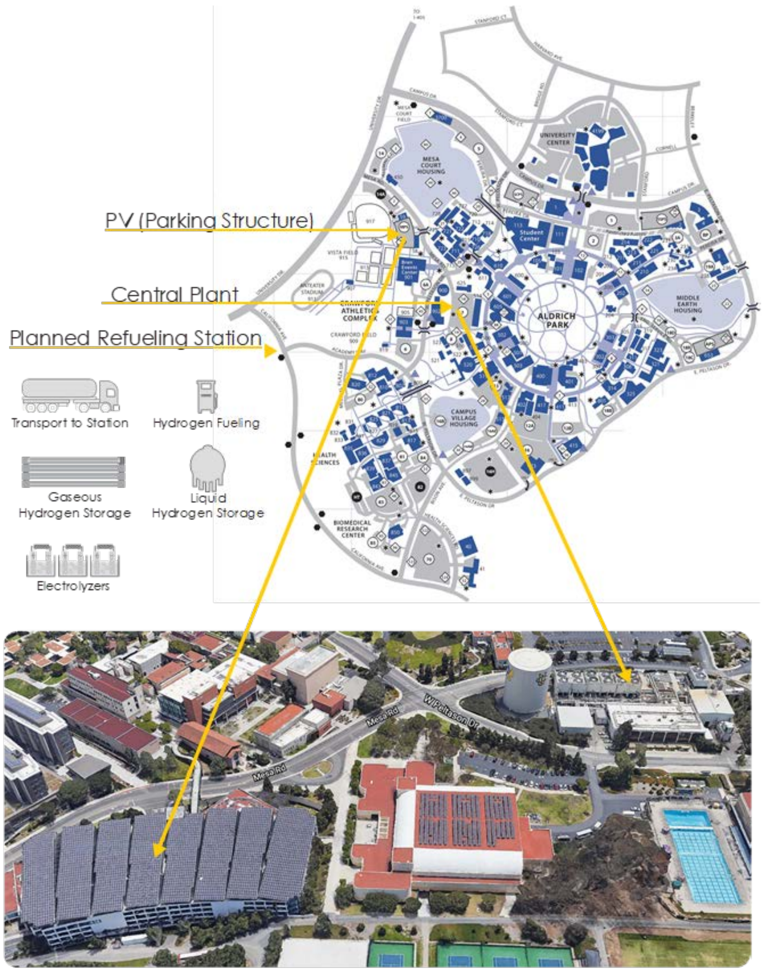

Figure 3. Overview of the Project Site Subject to Feasibility Study.

Technical tasks associated with the project include consideration of the following innovations:

- Turbine retrofit to enable operation on variable fractions of hydrogen up to 30%
- Integration of hydrogen generation technology with ability to receive waste heat from the gas turbine
- Physical interconnection via hydrogen pipe of the campus central plant and the campus hydrogen refueling station to allow joint use and co-optimization of hydrogen generation options and storage resources to serve either power or transportation demand
- An integrated control system to allow dynamic dispatch of ecosystem components

2 Methods, Assumptions, and Procedures

The effort started with research and evaluation of candidate technologies, evaluation of their relative footprints and capacity matches, and consideration for the location and specifications of the existing fossil asset on the UC Irvine campus. This effort is summarized in Appendix C—Technology Gap Assessment.

This effort led to a preferred initial design along with analysis of various operational and combinatory scenarios using these components. The analysis was carried out using existing simulation tools APEP has developed for simulation of the UCI campus grid (“DEROpt).[2] As part of the current effort several modules had to be added to DEROpt to complete the analyses required.

In addition, existing gas turbine operational data, costing estimates, and utility costs are be used to conduct a technoeconomic evaluation of the design considering various operational scenarios with appropriate utility rates including expected evolution of direct access tariffs for sourcing of off-site power to augment microgrid self-generation. Further discussion is provided in the Technology Maturation Plan and the Project Management Plan.

Finally, plans for maturing the technology along with a commercialization plan are incorporated into Appendicies

3 Results and Discussion

The results from the effort are described in this section.

3.1 Analysis Tools Augmentation

As part of the overall effort, upgrades to the existing Distributed Energy Resource Optimization (DEROpt) simulation code were exercised and validated. The resulting version of DEROpt is shown in Figure 4. As a reminder, the starting version included modules for the gas turbine, steam turbine, hot water generation, chillers, thermal storage

[2] Flores and Brouwer (2018). Optimal design of a distributed energy system that economically reduces carbon emissions, Applied Energy, Vol 232, pp 119-138.

tanks, solar photovoltaic generation, and battery electric energy storage. During the current effort, the following modules were added:

a. Gas turbine / Steam turbine thermal cycling costs associated with dynamic and start/stop operation
b. PEM and Alkaline electrolytic hydrogen production with financial aspects capturing charging from renewable and nonrenewable sources
c. Reversible high temperature electrolytic hydrogen production (not utilized nor shown in Figure 4)
d. Hydrogen compression and storage systems
e. Light duty hydrogen refueling
f. Offsite utility scale renewable powerplant and energy storage for electricity wheeling

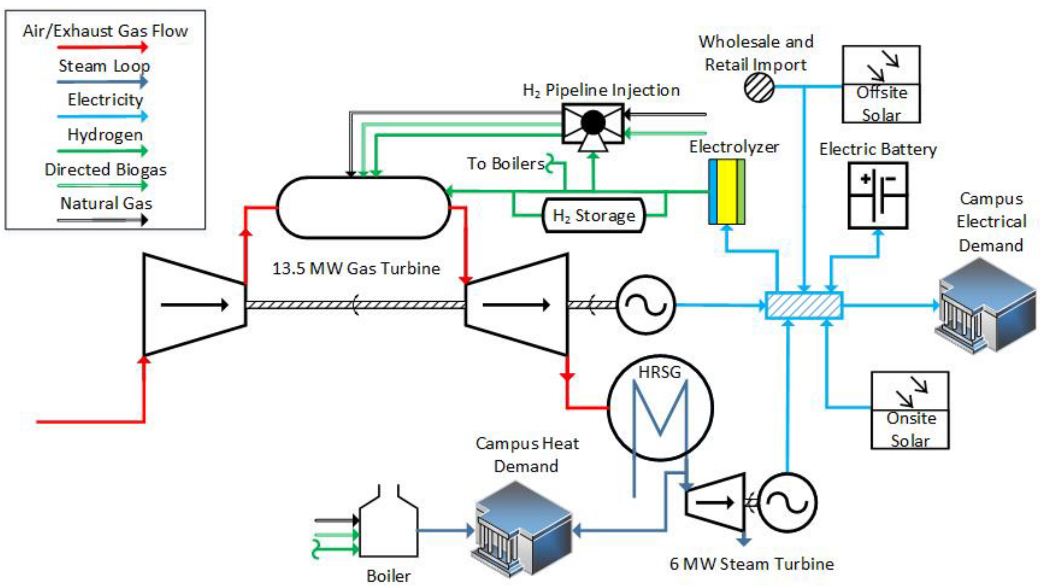

Figure 4. Schematic of Version of DEROpt developed and applied in current effort.

3.2 Technology Overview

The proposed hydrogen energy storage system will allow the turbine to maintain minimum load for air emissions compliance and provide renewable power at night. Use of electrolytic hydrogen produced and stored during times of high renewable production to provide renewable power via dispatchable thermal resources could provide a variable renewables integration solution for the entire roughly 450 GW fleet (according to the EIA) of natural gas generators in the U.S. alone. Of this, 82 GW (according to DOE) are combined heat and power systems, the configuration of the UCI microgrid. The proposed deployment will be the first of its kind in a microgrid environment in the United States. Component sizing and layouts were developed based on the target of 30% hydrogen fraction, available footprint, and results of the optimization analyses. The system elements are shown in Table 1 and discussed in the following sections.

Table 1. System Elements

Component / Element	Description
Turbine Retrofit Package	New components necessary to achieve 30% volumetric blend of hydrogen with natural gas
Electrolyzer Block	5 MW electrolyzer for hydrogen production
Hydrogen Compression	Redundant pair of 45 kw, 40 bar hydrogen compressors
Hydrogen Storage	2,400 kg above ground compressed hydrogen storage
Common Systems / Balance of Plant	Foundations, controls, electricals, and piping, other

3.2.1 Turbine Retrofit to Enable Operation on Variable Fractions of Hydrogen

The team from Solar Turbines evaluated the gas turbine system components that need to be retrofit to allow operation of the Titan 130 gas turbine on varying levels of hydrogen. The fuel requirement for the Solar Titan 130 is approximately 2400 kg/hr of natural gas which is approximately 1100 kg/hr of hydrogen. If the 30% (by volume) hydrogen target is adopted, this would imply about 330 kg/hr of hydrogen. With the Phase I feasibility study target of 2,200 kg/day, about 6-7 hours of daily operation at 30% hydrogen could be realized, allowing reasonable time shifting of the hydrogen generation and subsequent use. For the gas turbine to accept up to 30% H_2 in pipeline natural gas, the Phase I effort identified components within the system that require consideration. At the plant level, Figure 5 illustrates areas to be addressed/considered. At the engine package level (Figure 6), more specific areas to be addressed are shown.

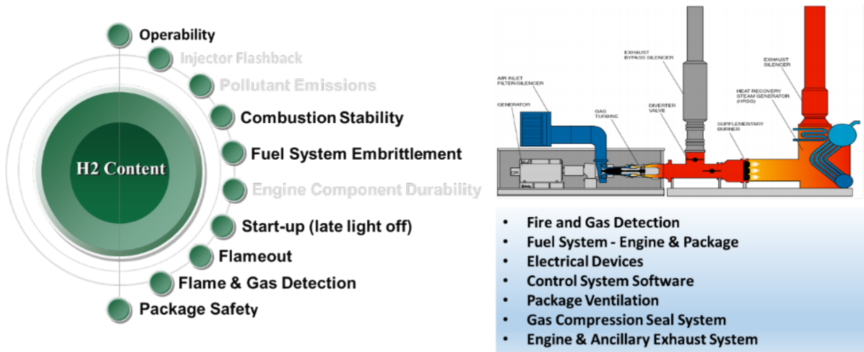

Figure 5. CHP Plant Operational Issues to be Addressed with Hydrogen addition.

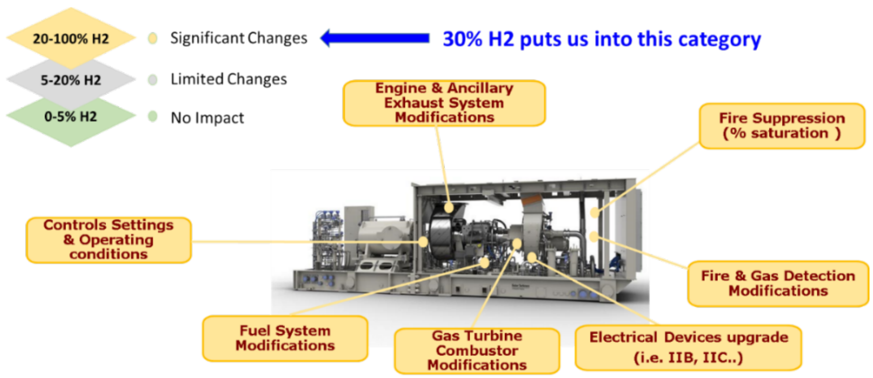

Figure 6. Engine Component Considerations with Hydrogen Addition.

It has been determined in Phase I that the 30% requirement requires significant changes to the gas turbine components and package. In the current project, emphasis was placed on fuel system and combustor modifications needed.

3.2.1.1 Additional H2 Readiness Assessment post Engine Overhaul & Package Upgrades Completed in 2022

The UCI gas turbine and package is targeted to undergo an engine overhaul and a package upgrade in 2022. An additional final hydrogen readiness assessment would remain to be conducted on the engine/package prior to any adoption of upgrades. A large percentage of the required upgrades for hydrogen operation were already included in UCI's plans for the 2022 overhaul/upgrade cycle. Since gas turbines are typically operated for 30,000 hours between overhauls, it is much more cost-effective to perform most of the upgrades at the next upcoming overhaul. The UCI facilities team would also necessarily need to be engaged in accepting possible upgrades which are beyond the scope of the current effort. .

3.2.1.2 Hydrogen Safety and Lower Explosion Limit (LEL) Solutions

Hydrogen poses risks to gas turbine operation at start-up and during upset conditions where flameout can occur.[3],[4] . Although failed start attempts and combustion flameouts are upset conditions, they are not rare. When they occur and before the fuel supply is shut-off by controls, a charge of unburned fuel and air can enter the exhaust duct with a mixture that is above the lower flammability limit (LEL). For fuels containing hydrogen, the LEL is reduced significantly so that these type of trip events can potentially create flammable mixtures with hydrogen and natural gas blends, which would not be flammable with natural gas alone. If this charge ignites and combusts within the exhaust system a substantial pressure rise can develop that could cause moderate to severe damage in the exhaust system. The extent of the pressure rise depends on how the charge of fuel burns. The flame would start as a slow flame. Depending on the equivalence ratio, the influences of mixture temperature and the duct geometry would either cause the flame to stay in the slow flame regime, transition into a fast flame, or in the worst case a detonation wave. The magnitude of the pressure rise also depends on the fuel composition, equivalence ratio and initial temperature of the fuel-air mixtures; the length, size, and shape of the duct; and obstacles in the flow path.[5],[6]

For the Titan 130 (T130) installed at UC Irvine operating on 30% Hydrogen by volume blended with natural gas, the fuel to air ratio in the exhaust will exceed the LEL but remain in the slow flame regime in the event of a flameout at full load. For existing gas turbine plants operating in the field, Solar Turbines has proposed the implementation of an exhaust air dilution system when required to lower the fuel to air ratio below the LEL to insure an un-ignitable mixture. The impact of the air dilution system has not been evaluated for operation with the waste heat recovery system. It is expected that it will

[3] Bauwens, C.R., Dorofeev, S., "Exhaust Duct Explosion Potential in Gas Turbines when Operating with Hydrogen Containing Fuels.", Report from FM Global, 2016.

[4] Uragrte, O., Menon, S., Rattigan, W., P. Winstanley, Saxena, P., Akiki, M., Tarver, T., , "Prediction of pressure rise in a gas turbine exhaust duct under flameout scenarios while operating on hydrogen and natural gas blends." GT2021-59777, Accepted for Proceedings of the Turbo Expo 2021 Turbomachinery Technical Conference & Exposition GT2021.

[5] Bradley, D., Lawes, M., Liu, K., "Turbulent flame speeds in ducts and the deflagration/detonation transition.", Combustion and Flame, 154 (2008), pp. 96-108.

[6] "Hydrogen Based Energy Storage System for Integration with Dispatchable Power Generator -Phase I Feasibility Study", DOE Award DE-FOA-0002332.

have a detrimental impact on the performance. For this reason, Solar Turbines is proposing the investigation of a passive mitigation for exhaust over pressure in the event of re-ignition after a flameout. NFPA 68 Standard on Explosion Protection by Deflagration Venting outlines approaches for pressure release devices that provide safe venting and reduce the overall mechanical design requirements of the exhaust to contain such an event. The use of a deflagration venting system will allow the turbine to safely operate with exhaust levels that could exceed 100% of the LEL for the gas composition.

Additionally, the use of burst disks in the exhaust ductwork for up to 30% Hydrogen operation in the T130 with the UC Irvine waste heat recovery system design is warranted. The first step is to understand the magnitude of the pressure rise in the event of re-ignition after a flameout. This will be done by using a computational fluid dynamics model that is tuned for predicting pressure rises in turbine exhaust systems[4]. The intricacies of the flow path in the waste heat recovery system will need to be modeled to determine the impact on the propagation of the flame and resulting pressure wave. Simulations will then be run on the different operating scenarios, such as, duct firing on and off. The worst-case pressure rise of the unvented deflagration will then be used as an input parameter for the design of the burst disk.

The key parameters for the design of the burst disk will include the exhaust geometry, maximum unvented pressure rise, the operating pressure of the system, and the design strength of the enclosure. The design process will yield a P-reduced value that is the maximum pressure the system will see in the event of a vented deflagration. If P-reduced is less than the design strength of the enclosure, then investigation of implementing the burst disk designs will proceed. If P-reduced is greater than the design strength of the enclosure, then an investigation into replacing a section of the system where the deflagration venting will occur with a strengthened duct will be the next step. Solar Turbines would work with a burst disk supplier and the EPC on the best methods for design and installation. The evaluation, beyond the current scope, will include a risk analysis and implementation impact.

3.2.1.3 Real Time Hydrogen Sensor Evaluation for Use with Closed-Loop Engine Control for NOx Emission Reduction

As described in the Phase I background information, existing dry low emissions (DLE) technology utilizing lean premixed systems for NOx reduction can have a small increase in emissions because of the diffusion style or partially premixed pilot fuel circuit used to provide stability to the main flame. For low blends of hydrogen (H2 <= 20%), the effect is only on the order of a few ppm of NOx[7] and can be handled for the most part with existing emission margins. However, as the fuel blend increases above 20% H2, the NOx emission increase can be larger and may affect existing emission requirements if left with the existing engine combustion system controls. One way to mitigate the additional NOx emissions is to use closed loop engine control based on the H2 content in the fuel. This control scheme takes advantage of the lower turndown capability with hydrogen that will allow reduced pilot settings and thus lower NOx emissions. To use this method, a reliable, low cost and fast acting sensor capable of determining the level of H2 in the fuel is required to be able to control the pilot fuel circuit in real time. An evaluation of existing technology available will be included as part of the Pre-FEED study to be performed by the EPC with input from Solar Turbines.

The current TRL of the hydrogen tolerant gas turbine is 6. Some of the proposed next steps would facilitate a path towards TRL 8-9 to be realized.

3.2.2 Hydrogen Generation Block – Electrolysis System

Power-to-Gas-to-Power hydrogen energy storage systems use electrolysis to store electrical energy in the form of hydrogen for later reconversion in hydrogen-fueled generation resources. There are variety of electrolyzer types employing different electrolytes. These include alkaline, proton exchange membrane (PEM), molten carbonate and solid oxide (SOEC) systems. Although Alkaline, PEM and molten carbonate electrolyzers are commercially mature, solid oxide offers the potential of greatly improved efficiency. Sunfire's recently introduced product, HyLink SOEC[8] can produce

[7] Ramotowski, M. and Cramb, D., "Enhancing Fuel Flexibility in Solar's® Titan™ 250 Dry Low Emissions Combustion System", ASME, GT2021-58986. Accepted for Proceedings of the Turbo Expo 2021 Turbomachinery Technical Conference & Exposition GT2021.

[8] SUNFIRE-HYLINK SOEC – TECHNICAL DATA. Sunfire-Factsheet-HyLink-SOEC-20210303.pdf

1,600 kg of hydrogen per day for an 84 %-LHV system electrical efficiency. Reversible solid oxide cells are also under development. These systems would allow hydrogen production and later reconversion to electricity with a single system. Such a system would be strongly considered if sufficiently mature at the time of implementation of the hydrogen-enabled microgrid. For purposes of the present analysis, several commercial PEM systems were used to assess space requirements and layout as PEM is the most commonly selected technology for recent projects. Costs were estimated based on a 2020 study of hydrogen production cost performed by UCI for the California Energy Commission[9] <roadmap reference>. A 5 MW electrolyzer capacity was selected based on turbine fuel demand and available footprint on campus.

3.2.3 Hydrogen Compression

Hydrogen compression technology is fully mature but is a significant cost and reliability element in the proposed power-to-gas-to-power system. Several commercial produces were assessed, and budget quotes obtained. In addition, a consulting engineer was engaged to advise compression system specifications and costs. The preliminary design basis for the analysis uses two compressors to provide redundancy and the assumed cost of compression is $250 per kilogram per hour of compression capacity for compression to 35 MPa.

3.2.4 Hydrogen Storage Approach

Storage of hydrogen at the 1,000 to 10,000 kilogram scale in a microgrid context can be accomplished in several ways. These include storage as compressed gas in pressure vessels, storage in liquid form in cryogenic vessels, storage as gas or liquid in carrier media at modest pressure, and geological storage accessed via common-carrier pipeline infrastructure. For a 2030 deployment, any of these options might be cost optimal, but for near-term deployment, compressed-gas storage vessels are the most viable option.

[9] Reed, J., Dailey, E., Shaffer, B., Lane, B., Flores, R., Fong, A., and Samuelsen, S. (2020). Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California, CEC Publication CEC-600-2020-002

For compressed gas storage, the Phase I assessment is that cylindrical tubes would be a better option than spherical vessels due to smaller footprint, more commercialized options, and lower cost. Several vendors provided budget quotes with a price range of $750 per kilogram for a storage capacity of 2,000 kg at a pressure of 35 MPa.

Bored-shaft storage is another option to be investigated further in Phase II. This approach can yield a small surface footprint per unit of storage and might be an attractive option if a greater storage capacity is required. Ardent Group is conducting a pilot study[10] to store 50,000 kg of H_2 underground at 22 MPa, which would cost around $450 Australian dollar per kg of H_2 (or $326 USD at the time of writing). This technology is estimated to be commercialized in 2022 which will be capable of storing 20,000 to 500,000 kg H_2 at a maximum storage pressure of 30 MPa.

Liquefied hydrogen (LH_2) storage is emerging as the most common approach for storage at hydrogen refueling stations. These facilities are supplied by large scale liquefaction facilities. For a microgrid application such as that envisioned here, cryogenic storage would require an on-site liquefaction facility. Due to economies of scale, micro-liquefaction is generally not cost effective. However, vendors are working to develop small systems at cost comparable to central facilities and this option will be further assessed during Phase II.

3.2.5 High Level Cost Analysis

Table 2 below summarizes the estimated costs for the proposed fossil-integrated storage system.

[10] Blind Boring - Ardent Underground

Table 2. High-level Cost Summary for Fossil-integrated Hydrogen Energy Storage System

Component	Size	Cost Basis	Cost ('000)
Electrolyzer	5 MW	$800 - $1000/kw	$4,000 - $5,000
Storage (Compressed Gas)	2,400 kg	$600-800/kg	$1,400 - $1,900
Turbine Retrofit	13 MW	Engineering est.	$1,500 – 2,000
Integration, Common Systems and Controls	n/a	Engineering Estimate	$2,000 - $3,000
Engineering, Procurement & Construction including Site Prep	n/a	Engineering Estimate	$4,000 – $5,000
Total			$12,900 - $16,900

3.2.6 Integrated Controls

The control system for the overall effort consists of integration of the subcomponent controls with the existing central plant operation. Additional work on developing the final design requirements for the operational signal to enable the gas turbine and the hydrogen fuel content composition signal will be developed in conjunction with the overall project design. Turbine controls will be optimized using the hydrogen fuel content signal to minimize exhaust LEL risk. Additional system design for inclusion of a hydrogen based energy storage system must also be added in order to cover short duration events before the gas turbine generator and CHP plant can be brought on-line to produce steam and electricity.

3.3 Proposed System Locations

Several meetings were held to arrive at a proposed location for the project. UCI Facilities Management nominated the area within the existing Facilities Central Plant adjacent to the existing turbine generator unit as shown in Figure 7 This space was reviewed carefully with the campus, facilities management, and the central plant for input and feedback. This site is very compact and is surrounded by features that will require innovative placement of the equipment. Figure 3 above presents a wider-area view of the installation location. Additional details are provided in Figure 8 along with images from the ground level in Figure 9- Figure 12.

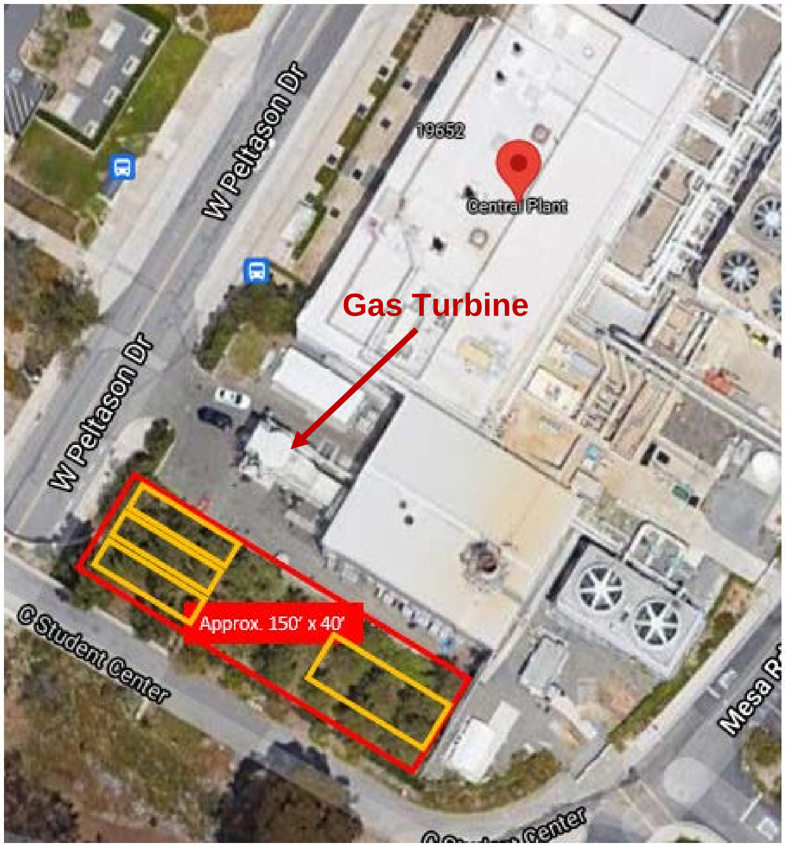

Figure 7. Overhead view of Proposed Project Space.

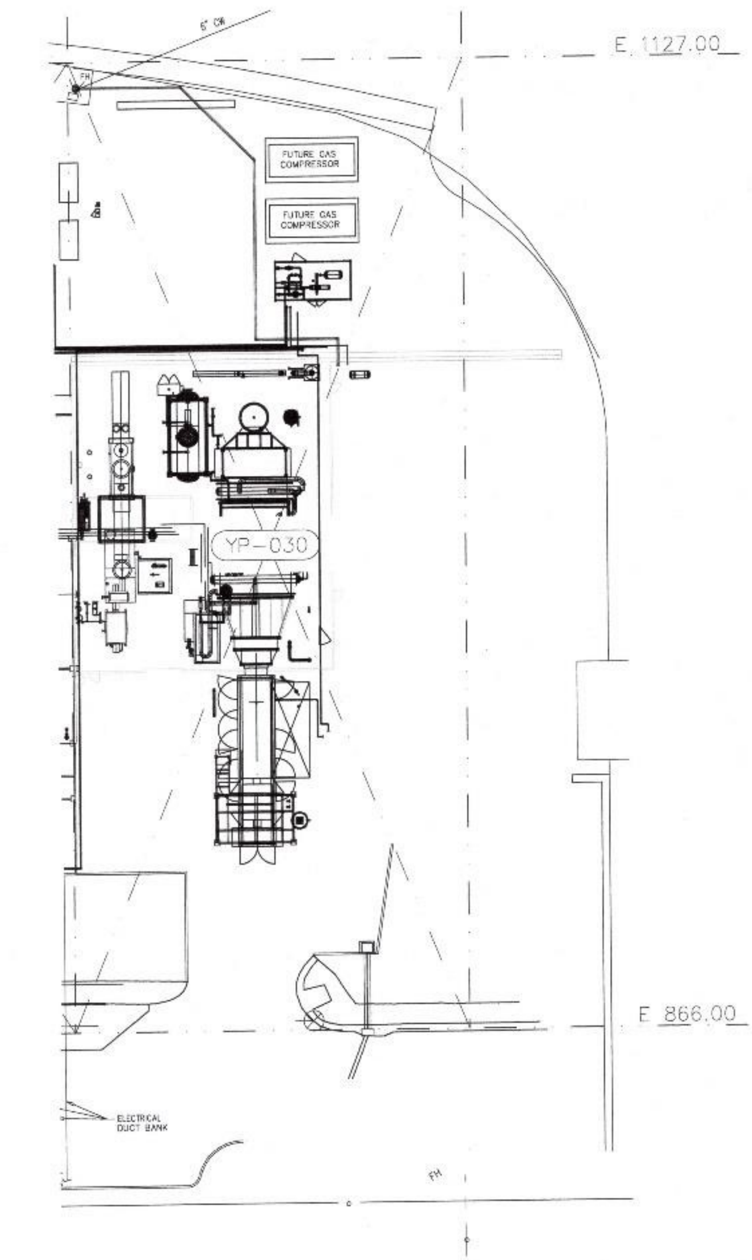

Figure 8 Overall Proposed Project Location


Figure 9 Heavily Wooded Side Slope (View from existing engine)


Figure 10 Heavily Wooded Side Slope

In addition, the east side of the proposed area is bounded by an approximately 30' high retaining wall (Figure 11). Also, there is a paved road at the top of the slope on the south side of the proposed site (Figure 12). These conditions place constraints on the available layout for the project.

Figure 11 Retaining Wall on East Side

Figure 12 Roadway on Top of Slope

In developing options for equipment layout, not only are the dimensions of each component considered, but space around each for access for operations and maintenance must be provided. Too, separation of equipment in accordance with NFPA 2 hazardous zones must be allowed. Costs for site development were not directly considered, but an effort was made to minimize extensive earthwork and associated retaining walls. Also, it was considered prudent to leave as much of the existing paved area directly south of the existing facility to provide for access to the optimum layout for the proposed project equipment.

Two overall storage scenarios were considered for the project, one using storage tubes and the other using the Quantum composite storage trailers. Either are suitable for the purpose, but, as noted above, the Quantum units may not be approved by the AHJ. For one arrangement using Quantum storage, these were positioned near the street for ease of installation on the mobile trailers.

Two iterations of each scenario were developed and are presented in Figures 9-12. The dimensions of the “boxes” representing the equipment shown on the labels are inclusive of the area needed for access and to comply with appropriate codes. Other iterations are certainly possible, but these presented are intended to show that there is sufficient space in the proposed area to accommodate the equipment. When specific equipment is selected and a more detailed assessment made, no doubt other arrangements will become apparent.

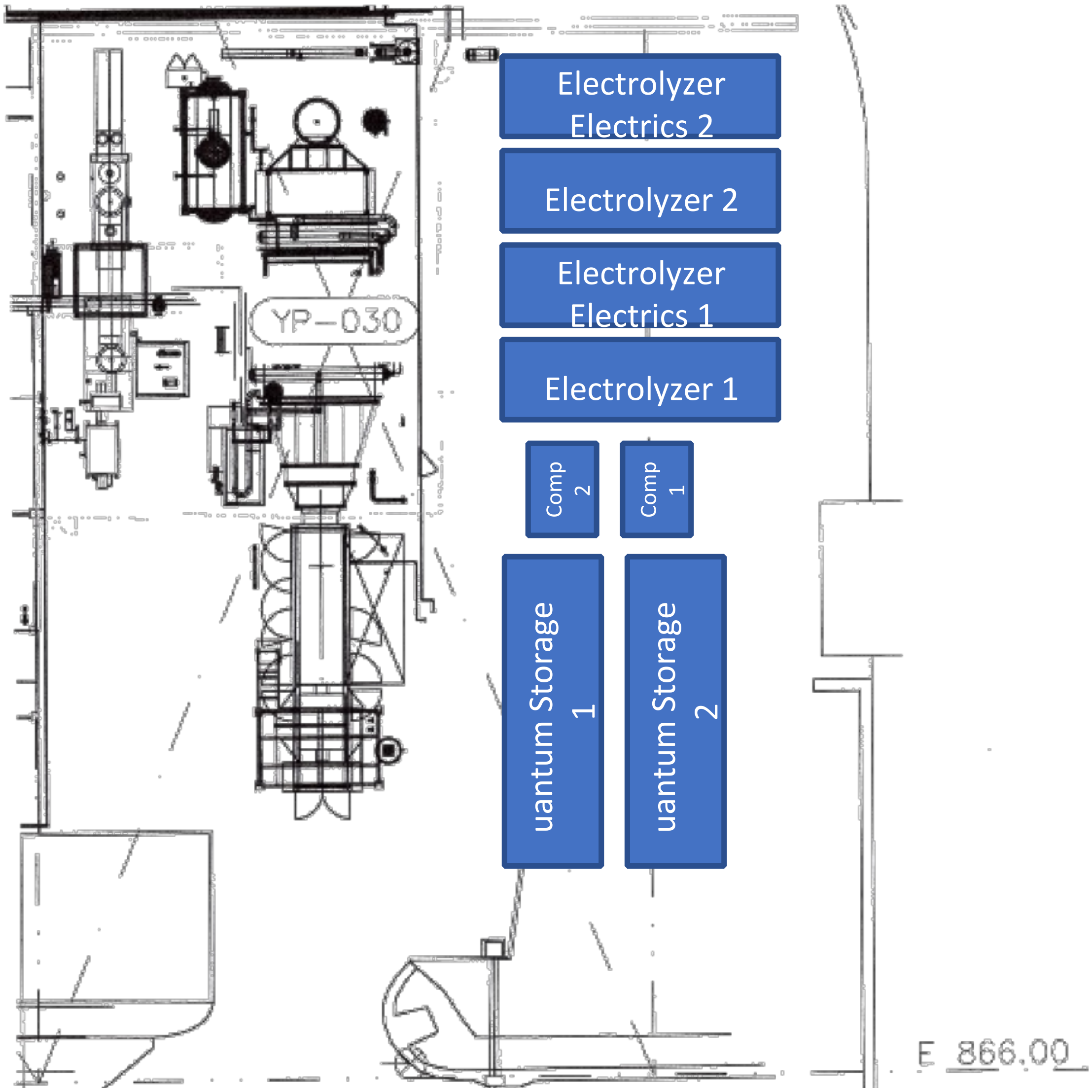

Figure 9 Proposed Layout 1

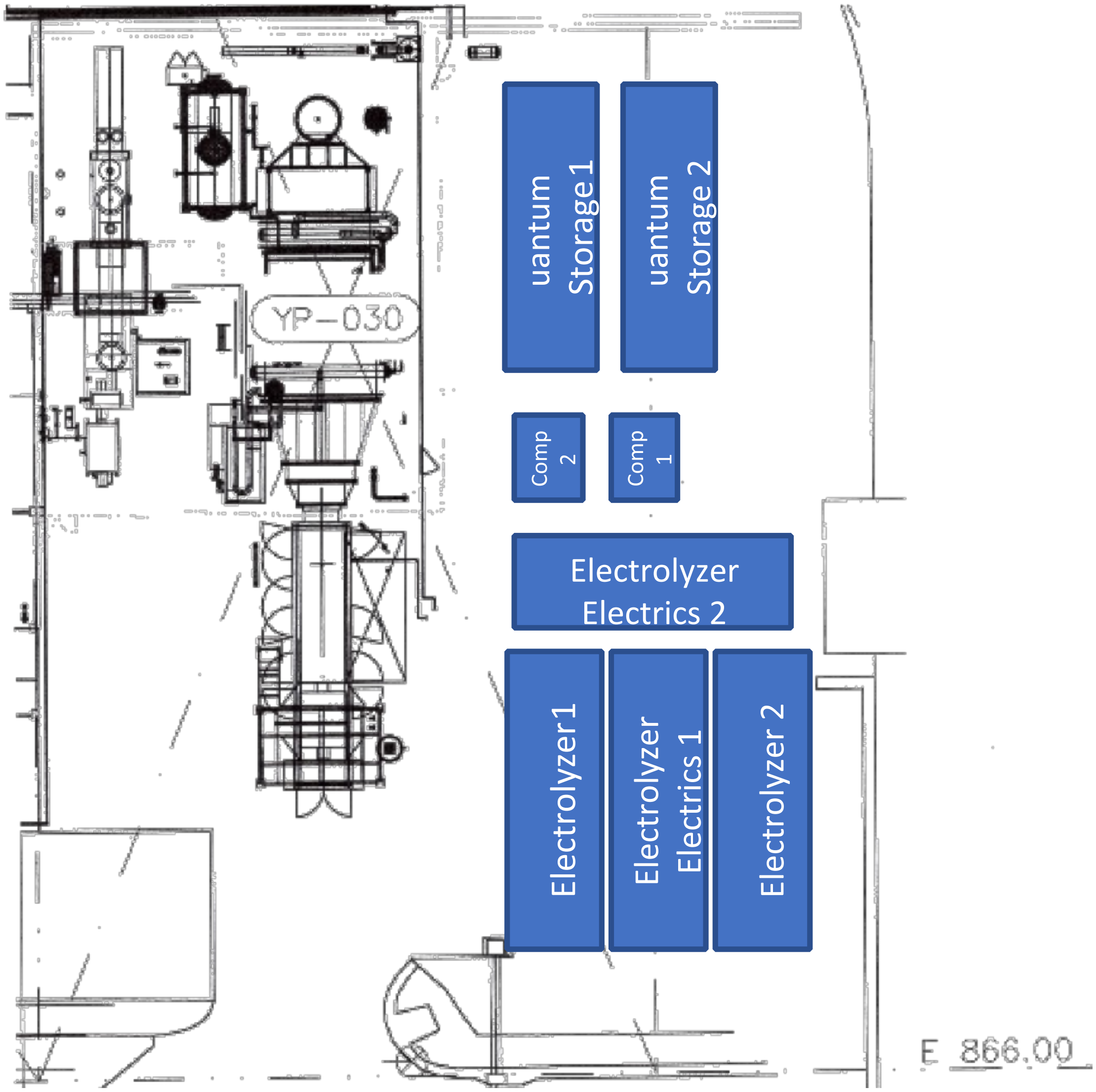

Figure 10 Proposed Layout 2

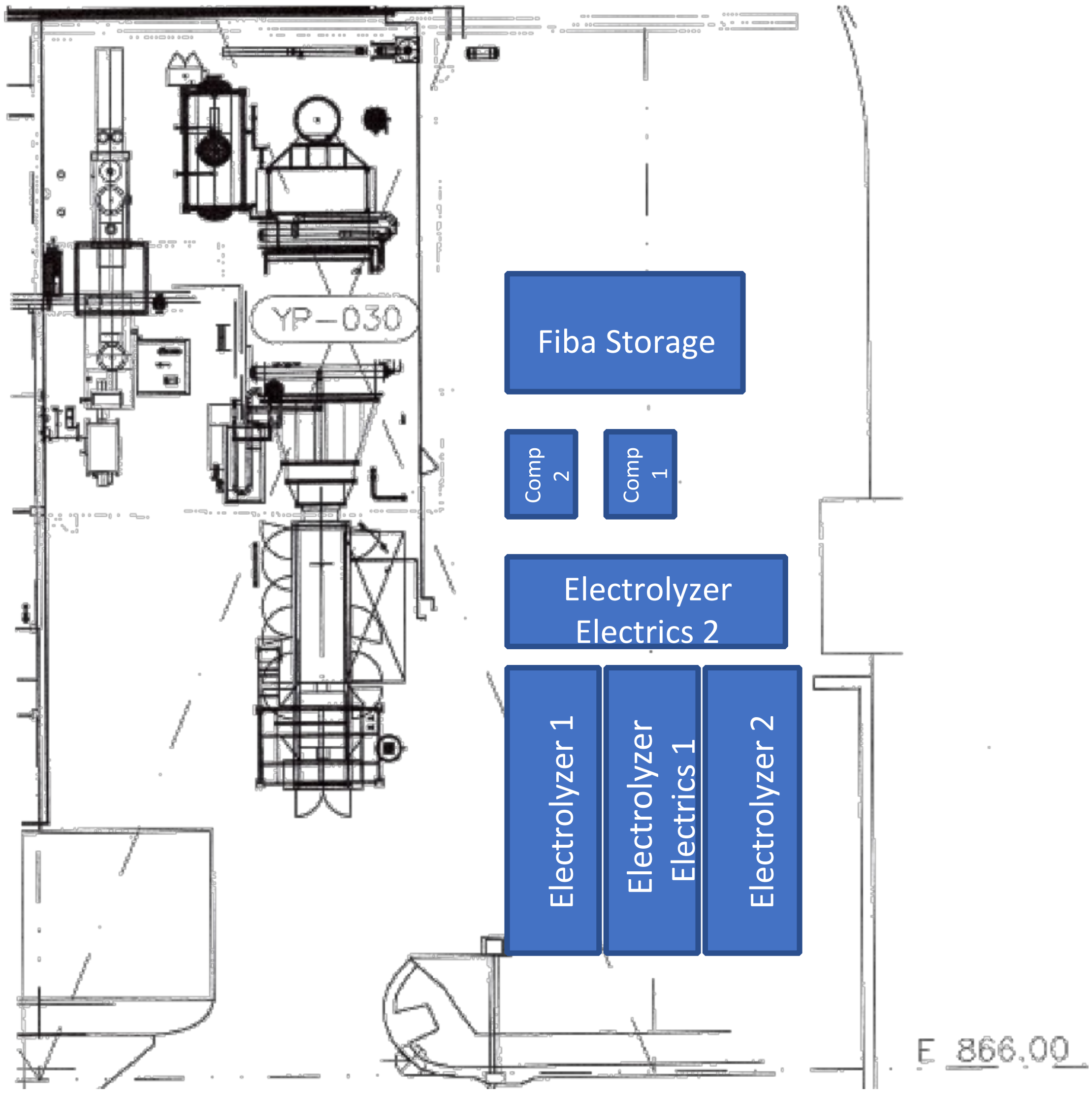

Figure 11 Proposed Layout 3

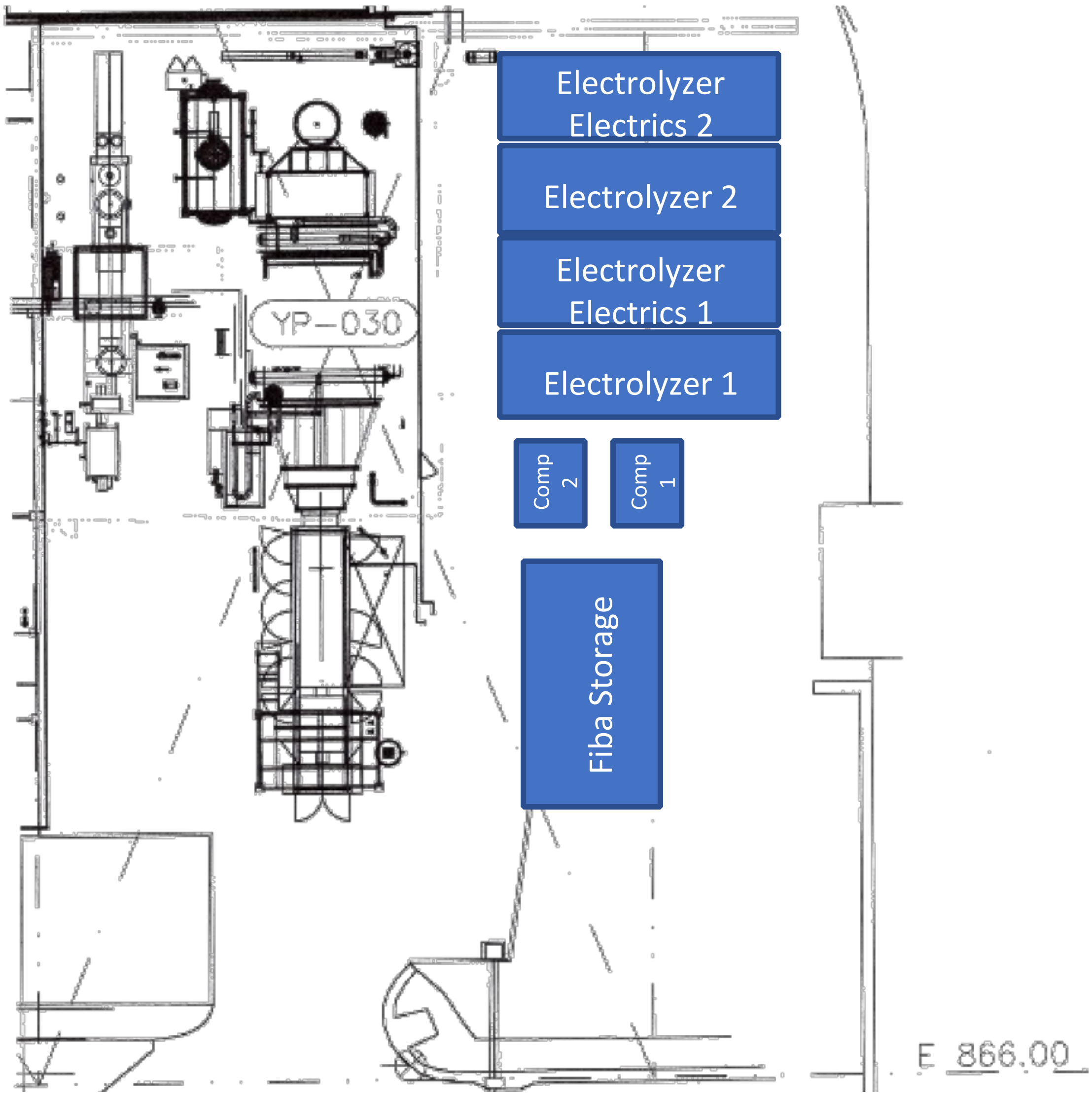

Figure 12 Proposed Layout 4

Based on the Phase I analysis, the positioning that is promising involves a location adjacent to the existing gas turbine plant as shown in Figure 13. What remains are the tie ins to the gas turbine fuel line and the power needed for the hydrogen handling equipment. The power connections are located opposite from the proposed equipment locations so is convenient to the overall system.

Additional consideration was given to the specific scope and space allocated for the project. Figure 2 above shows the elements that were considered in the current effort (along with compression).

Although final equipment selection has not been made, the general arrangement was developed using several commercially available products for reference. Redundancy in the compression and hydrogen generation is illustrated. The Phase I conceptual design was based on NEL MC500 electrolyzers (1,095 kg/day nameplate). As shown, each electrolyzer requires an electronics container with transformers, rectifiers, controls, and other components. The electrolyzers will produce hydrogen at about 30 bar which is nearly sufficient to fuel the gas turbine. However, to facilitate storage, two Hydro-Pak LX gas compressors are shown to take the hydrogen to 35 MPa. Various storage options were evaluated in Phase I, and a leading option is Quantum Fuel Systems VP5000-H which can contain 1,195 kg of hydrogen at 35 MPa. Note that the component layouts shown are inclusive of the are needed for access and to comply with appropriate codes.

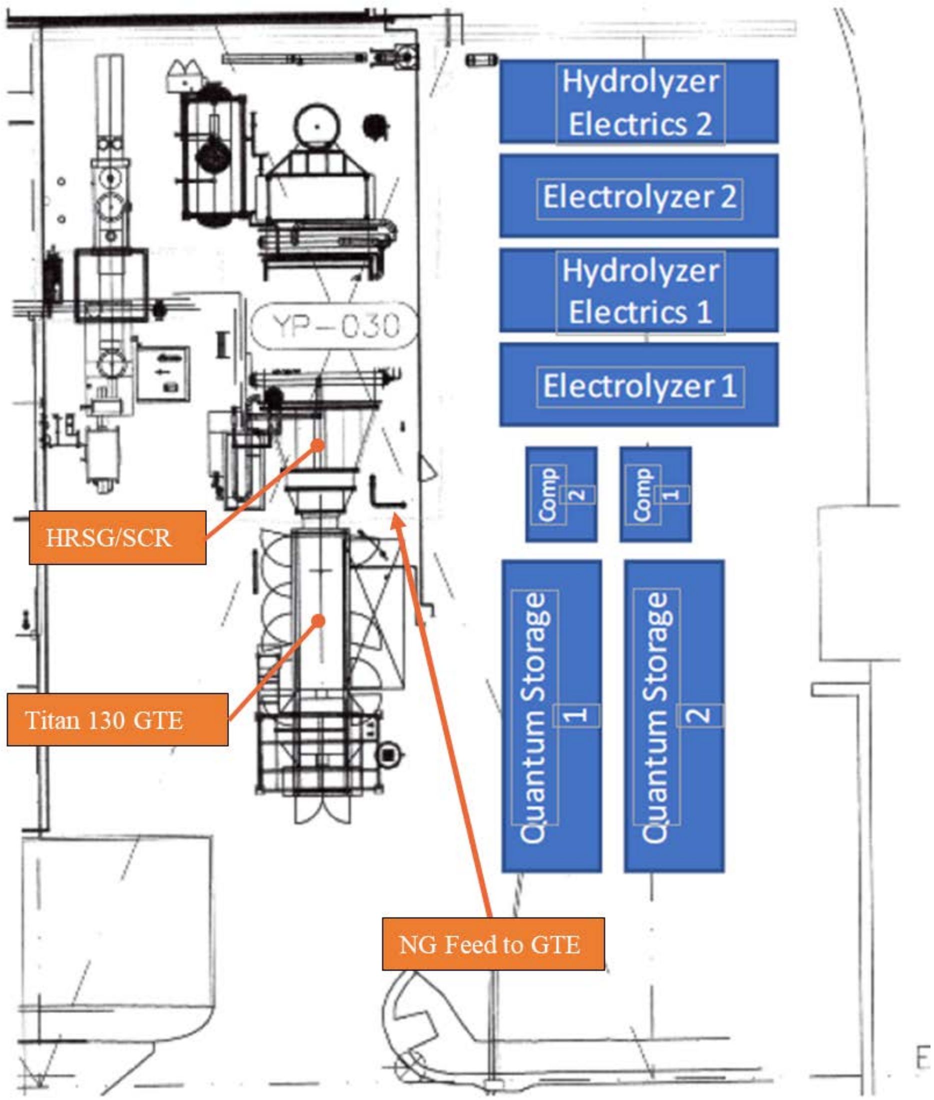

Figure 13. Preliminary equipment layout for hydrogen energy storage system

A key next step in finalizing any sort of Pre-FEED design is the evaluation of the various scenarios for placement and infrastructure Along with placement, the control system needs to be evaluated. Solar Turbines has developed a control system for an integrated gas turbine/battery storage system. This will serve as the basis for a similar system to control the hydrogen-based energy storage system proposed. To begin, the control algorithm for the gas turbine will be specifically reviewed to validate fuel flexibility for Phase 2 optimization for the Dry Low Emissions (SoLoNOx™) controls. Emissions performance and combustion stability will be conceptually assessed in Phase 2 through mapping and adjustment of pilot / main fuel split and part load combustor primary zone temperature. Special instrumentation needed to complete this testing for TRL 9 level evaluation will be defined. Next, the package controls microprocessor will be reviewed, and upgrades identified to ensure it will support planned operational needs and special testing.

As indicated above, several components needed are commercial, but the current TRL of an integrated system is set at 4-5. It is expected that the current effort will facilitate migrating the level of the integrated system to TRL 6-7 with remaining needs to attain TRL 9 identified in the final Technology Maturation Plan.

3.4 Analysis

The University of California (UC) system has committed to achieving carbon neutrality by 2025. Accordingly, the UCI campus has established the goal to achieve real-time zero-carbon operation for its microgrid (no use of net metering or credits to offset carbon emissions). The Phase I effort investigated the value of hydrogen energy storage as a resource on the UCI microgrid, shown in Figure 3 above, through integration with its existing 19 MW combined heat and power system. Both operational benefits and carbon reduction are primary objectives. Economic dispatch of the potential hydrogen-supported microgrid was modeled using the UCI Distributed Energy Resource optimization (DERopt[11,12,13,14,15]) model which was enhanced to include H_2 technologies. DERopt is a techno-economic energy systems optimization tool that determines lowest cost technology investment and operation while meeting emission targets. Top-line analysis results are summarized in Table 3 and discussed further below.

[11] Github repo: https://github.com/rjflores2/DERopt

[12] Flores, R, & Brouwer, J. (2018). Optimal design of a distributed energy resource system that economically reduces carbon emissions. *Applied Energy*, *232*, 119-138.

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[15] Novoa, L., Flores, R., & Brouwer, J. (2021). Optimal DER allocation in meshed microgrids with grid constraints. *International Journal of Electrical Power & Energy Systems*, *128*, 106789.

Table 3. High-level analysis results summary

Use Case	Finding
Reduced turbine cycling	The cost of maintaining constant output via hydrogen production and later reconversion is higher than the cost savings from reduced cycling so there is not a positive stand-alone business case for this use case.
Maintain minimum power for air emission compliance	Electrolytic hydrogen is adopted as the least-cost solution when the carbon constraint limits the ability to use natural gas to maintain minimum power. This case also avoids the cost of shut-down and restart.
Time shifting of variable renewable supply (daytime solar to hydrogen and nighttime hydrogen to power)	Hydrogen is cost-effective for load shifting when low-cost renewable power is available during midday and electrolyzer cost and efficiency are as projected in the 2025 and beyond timeframe.

3.4.1 Reduced Turbine Cycling

A major challenge for integrating renewable energy into conventional fossil-fueled gas turbines (GT) is a need for increased cycling of the asset. The UCI microgrid is already experiencing reduced capacity factor due to campus solar power as shown in Figure 14.

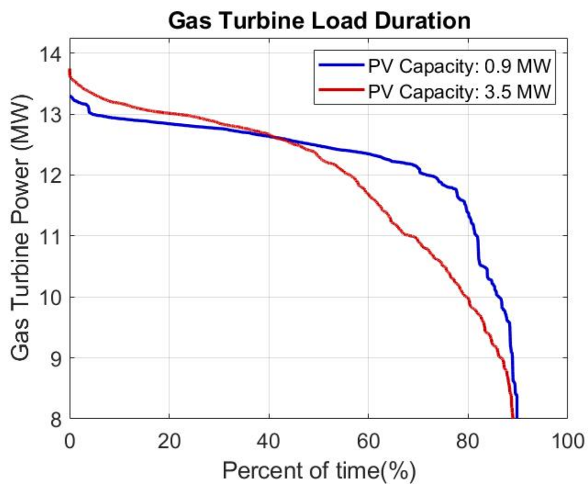


Figure 14. Actual Operational Data Illustrating Impact of Installed PV on UCI's Gas Turbine Operation Profile.

The National Renewable Energy Laboratory (NREL) collaborated with Intertek [16] to estimate lower bound costs of cycling more than 500 currently operating power plants. The UCI Solar Turbines Titan 130 13.5MW natural gas fired GT is expected to consistently operate except for scheduled maintenance. As a

[16] N. Kumar, B. Peter, S. Lefton, and Agan Dimo, "Power Plant Cycling Costs," Contract, vol. 303, no. November, pp. 275–3000, 2012.

result, the costs for the UCI asset would be associated with load following O&M scenario which NREL estimates to be about $1/MW capacity. Consider the case in which the GT ramps down to 60% of its maximum power output (15MW) and back up to max power for an 18 MW load cycle. This translates to about $18, during which time the energy produced would be around 2,000 kWh. This translates to around $0.01 per kWh added cost associated with the cycling. In other words, by operating at full load instead of cycling $0.01 per kWh would be saved. However, considering the site specific fuel cost of around $0.04 to $0.05 per kWh, it is evident that cycling the GT would be more cost effective than operating the GT at full power and producing hydrogen.

In the future, low-cost midday solar could lead to economic shutdown of the GT during the middle of the day. However, as discussed below this would violate air emission permitting constraints for the site-specific case and the avoided shut-down and restart costs of about $130,000 per year reduces the net cost of maintaining the turbine at minimum load.

3.4.2 Maintaining Minimum Power Output for Emissions Compliance

At expected 2030 electrolyzer capital cost below $500/kw and cost of electricity imported renewable energy of $35/MWh (expected future wholesale access rate), renewable hydrogen could be produced for less than $20/MMBtu . The economics of this pathway are comparable to the use of biomethane to perform the same function. Obviously, this power-to-gas-to-power use case is more costly than direct use of solar energy. However, the use case is cost effective for meeting the minimum power constraint. Figure 15 shows a representative dispatch for this use case. The hydrogen storage required for this use case is only a small amount of buffer storage allow a constant flowrate of hydrogen to the turbine during times when on-campus solar production and/or load is fluctuating (which cause the inverses fluctuation of grid power). However, this use case can operate in tandem with use of hydrogen for time shifting and improves the economics of the combined use case.

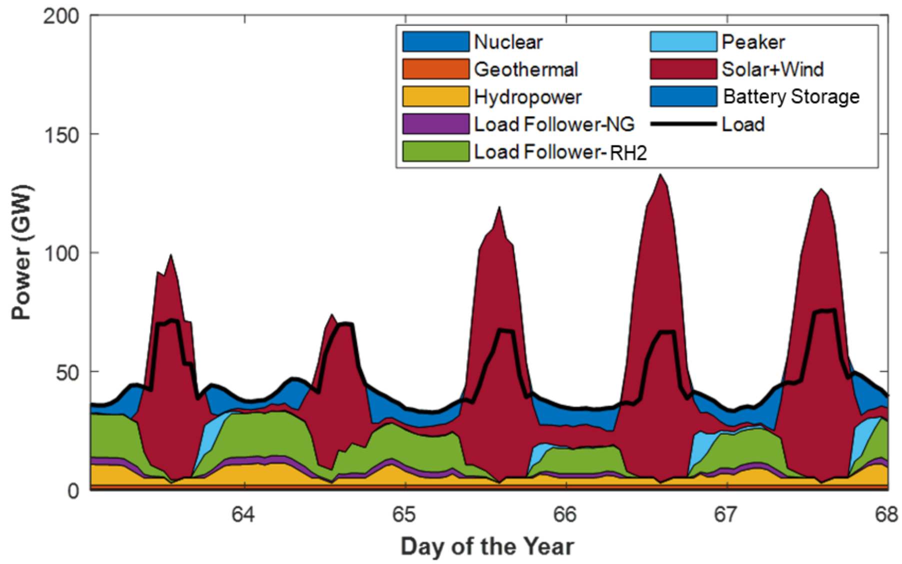


Figure 15. Grid dispatch of renewable hydrogen for firming variable renewables using the UCI HiGRID dispatch model.

3.4.3 Time-shifting Renewable Power

Like the macrogrid, microgrids will need zero-carbon power 24x7 to achieve full decarbonization. In solar-dominant systems, this is achieved by time-shifting renewable supply from midday to other hours through storage. Currently, batteries are the most common approach to accomplish this, but hydrogen energy storage has great promise for providing storage functionality over longer periods. Hydrogen as a storage approach also has the advantage that existing thermal generation resources can be used to reconvert stored energy to electricity. This use case was analyzed in prior work by UCI for the California grid and the result, shown in Figure 16, was that hydrogen becomes cost-effective for firming of renewables at a cost of about $3/kg of hydrogen delivered to a hydrogen-capable turbine (~$2.5/kg injected onto the pipeline).[17] Recent analysis on dispatch of grid-connected electrolyzers conducted as part of a UCI collaborative research and development project with NREL show that achieving hydrogen production cost of $2/kg in the 2025 – 2030 time frame is feasible. At this cost point, power-to-gas-to-power is more cost effective than battery storage and provides reliability and resilience benefits. At the DOE Hydrogen Shot goal of $1/kg, hydrogen energy storage is highly

[17] RESOLVE white paper.

cost effective. Figure 15 shows the California grid optimal dispatch with $1/kg renewable hydrogen available from the UCI HiGRID capacity expansion and dispatch model. For the campus microgrid, the UCI DEROpt model was used to model the use of hydrogen for load

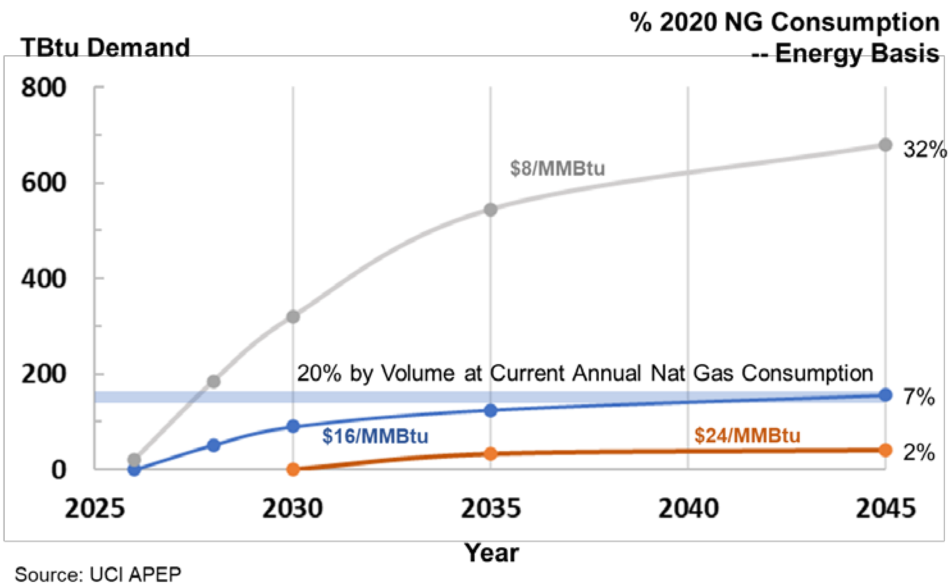


Figure 16. Grid-supplied hydrogen adoption as a function of price and year on the California grid using RESOLVE model.

Figure 17 shows a representative dispatch result for the equipment set proposed here. For a direct comparison of storage cost effectiveness, a levelized cost of storage formulation taken from Schmidt et al. (2019)[18] was applied using the primary parameters shown in Table 4 and presented in Figure 18. Both cases assume that charging power costs $40/MWh consistent with the marginal production cost of the GT and an assumed future option to import off-site large-scale solar PV under assumed wholesale access tariff (campus as transmission-only customer). Although the battery case shows slightly less expensive, future cost improvements and efficiency enhancement of the GT may change this ranking, and the hydrogen case improves the reliability and resilience of the campus microgrid. Roundtrip efficiency hurts the economics of the hydrogen case. The potential

[18] Schmidt

for improved efficiency as part of a major overhaul to enable hydrogen capability will be investigated in Phase II.

Table 4. Storage for time-shifting scenario parameters

Parameter	Battery	Electrolyzer
Capital Cost for 8 hour discharge	\$1,050/kwh (NREL[19])	\$800/kw + \$600/kg storage (UCI[9])
Round-trip Efficiency (%)	81%	25%

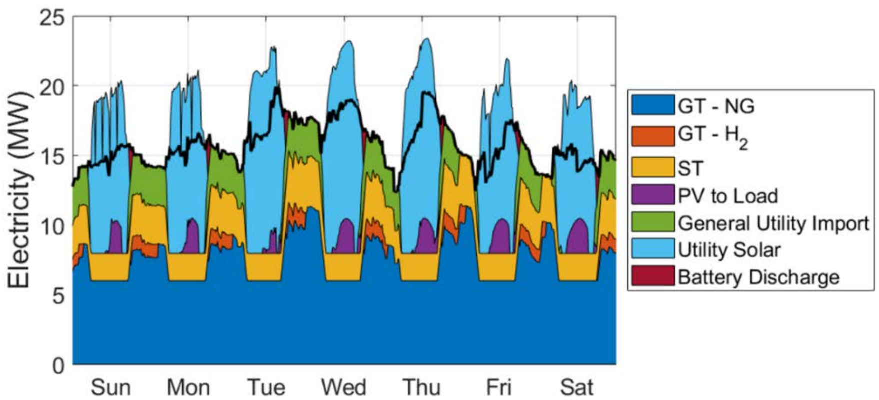
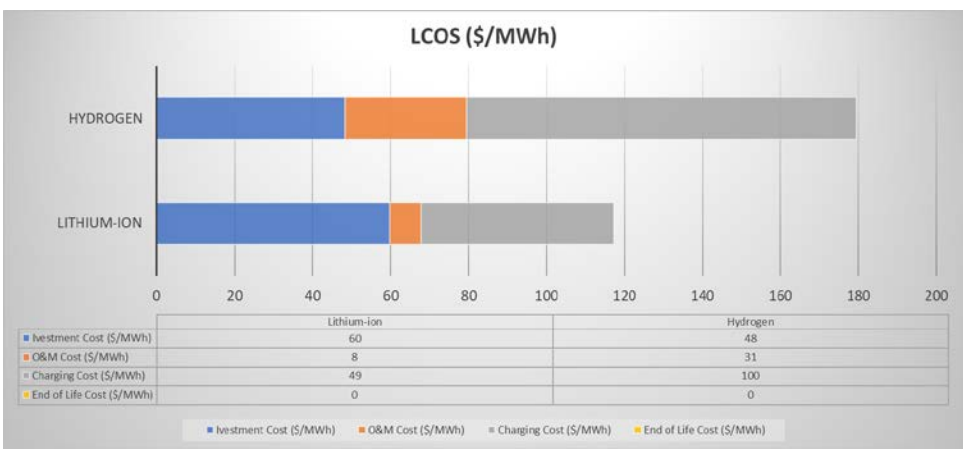


Figure 17. Example dispatch of hydrogen for time shifting renewable power – red area is hydrogen-fueled portion of GT power dispatched at night. .



	Lithium-ion	Hydrogen
Ivestment Cost ($/MWh)	60	48
O&M Cost ($/MWh)	8	31
Charging Cost ($/MWh)	49	100
End of Life Cost ($/MWh)	0	0

Figure 18. Levelized cost of storage comparison for UCI campus parameters and 12-hour storage duration

[19] NREL (2020). Lithium Ion Cost Update

3.4.4 Initial Commercialization Targets

The central plant facility at UCI is representative of hundreds of similar facilities which are typically located within the "MUSH"(Municipal, University, School, and Hospital) market sector. Within the State of California, the university sector alone has at least 9 examples at 10 UC and 47 CSU campuses. Many of these and other examples within the MUSH market are powered with Solar Turbine Gas Turbines. Related to the current effort, for example, there are 145 Solar Turbines gas turbines installed at university campuses or medical centers with similar CHP applications as the UC Irvine site. Of these, Solar maintains research and educational relations with several. It is expected several of these would work with the proposing team to facilitate application of TEA for their site. The TEA will provide benefits to the university, both for educating their students about the impacts of a hydrogen economy and for informing their future carbon reduction efforts for their energy facilities. Multiple options need to be developed since no single solution will apply at every site. Some examples of varying solutions include on-site hydrogen generation, transportation, and/or storage; integration of biofuels (e.g., renewable natural gas, biodiesel); and local ordinance and zoning requirements. Each site will have some unique constraints associated with emissions, export of power, cost of fuel and electricity, incorporation of various tariffs, etc. However, based on the direction of these factors determined by Hydrogen Roadmaps, various projections can be made.

4 Conclusions

The situation at the UC Irvine campus, with its constraints, biogas contract, and relative rates is challenging for a strong economic case for using renewable electricity to generate hydrogen, store it, and use it strategically to help decarbonize the campus. Various future scenarios could transpire to allow the concept to work out favorably, but this includes access to hydrogen from the larger grid, consideration for electricity export, and access to lower cost renewable electricity.

5 Recommendations

A number of possible future steps are outlined in the Appendices. However, it is evident that technology advancement is needed for the Solar Titan 130 engine system and integrated controls. Generalization of these results is difficult, and it would be prudent to assess several other specific market situations and geographic locations to establish more general findings.

Appendix A—Technology Maturation Plan

FINAL TECHNOLOGY MATURATION PLAN

For

“Hydrogen Based Energy Storage System for Integration with Dispatchable Power Generation—Phase I Feasibility Study”

28 February 2022

US Department of Energy Contract FE-0032021

DE-FOA-0002332

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U.S. Department of Energy
National Energy Technology Laboratory

A-1 Introduction

For the proposed integrated hydrogen-capable turbine and storage system to be successfully deployed as a commercial solution, technology maturation is needed on three levels: advancement of turbine systems and components to accommodate hydrogen blends of up to 30%, integrated controls to facilitate coordination between the hydrogen storage components and the turbine, and optimization of the integrated energy production and storage system of systems operating as a power-to-gas-to-power micro and macro-grid resource. The following section describe the status and maturation of these elements expected under the current project and post project efforts.

A-2 Technology Readiness Level

A-2.1 Gas Turbine Technology for increased hydrogen addition

The completed program did lead to a proposed one-year Pre-FEED study that even itself would require an additional follow on program to test a full scale industrial gas turbine on up to 30% hydrogen blended with natural gas in a hydrogen based energy storage system for integration with dispatchable power generation. The current Phase I project started with the dry low emissions (DLE) combustion system of the gas turbine currently developed up to TRL-6 with hydrogen fuel blends. Plans were generated for executing and achieving a TRL-8 on a full scale pre-commercial field test that could potentially follow on from the current effort.

The target commercial application is Solar Turbines' Titan™ 130. The Titan 130 has multiple applications, including Combined Heat and Power (generator set with HRSG), Power Generation (simple cycle generator set), and Oil and Gas midstream and upstream (compressor set or mechanical drive).

Solar's current Titan 130 gas turbine engine with a SoLoNOx (DLE) combustion system is TRL-9 with respect to wide range of gaseous and liquid fuels, but is currently limited to 20% hydrogen in natural gas fuel based on the lack of hydrogen engine test capability for qualification at higher levels. Engine test capability with hydrogen fuels is a known limitation for many gas turbine manufacturers requiring projects such as this to set the stage for field demonstrations to push the technology readiness level higher. As a result, the proposed 30% H2 blended into pipeline natural gas represents a TRL-6 status today. Single fuel injector rig tests have been conducted at high pressure, but no engine test has been performed for final qualification. Solar's Titan 130 fuel injector design (part number 206640) is the basis for the current injector design and was extensively rig tested on hydrogen blends with natural gas under DE-FC26-09NT05873 with up to 65% H2 without flashback.

Solar also has conventional (diffusion) combustion systems that are TRL-9 for a wide range of gaseous and liquid fuels including operation at up to 100% hydrogen. The conventional combustion system is much more fuel flexible than modern DLE combustion systems. As a result, the technology focus on the engine packaging and controls portion of the project will focus on 1) integrated controls with the hydrogen energy storage system, 2) required upgrades for safe operation with hydrogen and 3) addressing possible start-up and flameout safety conditions with respect to the wider flammability limits of hydrogen containing fuels.

A-2.1 Controls for Integrated Gas Turbine/Hydrogen systems

Solar gas turbine products are provided with integrated controls that have the ability to burn a wide range of fuels including hydrogen. For this project, the design of the standard hydrogen engine and package controls would need to be updated for operation with up to 30% H_2. Solar Turbines has interest in further developing the integrated controls. As an example, Solar has developed an integrated control system for a gas turbine/battery energy storage systems (BESS). It is also committed to further develop Solar's Engine Health and Monitoring system (called Insight System™) for overall engine/package and BESS control integration. This will be accomplished by engaging Solar Digital in the effort. In addition, the engine/package controls will have an interface signal with the hydrogen storage system to be able to provide quick start capability or rapid switch over to a hydrogen fuel blend when directed by the system operator. Alternatively, the process could be automated for periods where renewable electricity is reduced or curtailed.

A-2.2System Optimization and Integrated System Design

The integrated, round-trip hydrogen energy storage "ecosystem" requires a number of systems in addition to the hydrogen-capable turbine whose development needs were described above. Specifically, a system to convert electric energy into hydrogen, a means of storing the energy at multi-MWh scale and interfaces to deliver the hydrogen back to the turbine are needed. Commercial solutions exist to serve all necessary functions, however, system sizing and operating requirements need to be optimized. In addition, there are configurations to explore that can use both heat and power from the main power block. Furthermore, selection of leading-edge but low-technology-risk solutions for electrolysis, hydrogen storage and hydrogen compression is critical to achieving the least-cost, best-fit configuration.

A-3 Proposed Future Work

A-3.1 Gas Turbine Technology for increased hydrogen addition

The current project is a Phase II effort that further identifies the requirements for both the gas turbine engine and package to support fuel blends containing up to 30% hydrogen with pipeline natural gas as well as developing the integrated control system with the hydrogen storage system. The upper range of 30% hydrogen was chosen based on recent literature which states that 30% may be the practical limit for existing natural gas infrastructure without requiring modification or causing detrimental effects [2, 3]. The plan developed at the end of the project will detail the necessary requirements to build and test a full scale system based on UCI's gas turbine power plant featuring a Solar Titan 130 gas turbine. The new work for this feasibility study is to identify and develop a test plan to qualify the DLE combustion system from TRL 6 to TRL 8, identify the engine package upgrades required and integrate the engine controls with hydrogen storage to allow operation on up to 30% H2 blended with pipeline natural gas. Depending on how the gas turbine system is dispatched and how long it runs, a minimum 11% reduction in carbon dioxide emissions could be realized with the system operating on up to 30% H2 in simple cycle mode.

The test plan for engine qualification is based on several factors and potential challenges of hydrogen combustion in existing lean premixed systems including flashback, combustion acoustics (oscillations) and emissions.

Hydrogen has a higher flame speed than natural gas and as a result, presents a higher flashback risk. In order to reduce the flashback risk during an engine test, the injector design is first tested in a high-pressure rig at the relevant gas turbine engine conditions to map out and determine the flashback limits across a wide range of operating conditions. In addition to the rig testing, instrumented injectors with thermocouples located inside the premix duct are used during engine tests to further mitigate the risk of a flashback by detecting the event and taking appropriate engine control action to prevent any hardware damage. Based on Solar's rig and engine testing of Associated Gas (AG) and conjugate heat transfer analysis, the impact of H2 on liner durability is not expected to be an issue [8]. As a result, Solar does not plan to instrument the liner in the fielded engine, but will perform periodic borescope inspections to monitor conditions.

With hydrogen's faster flame speed, the shape and position of the flame can change when higher amounts of hydrogen are added to natural gas. As a result, combustion acoustics and injector durability can be causes for concern. The effect of hydrogen on injector durability can be partially studied in the rig environment. However, combustion pressure oscillations require a full scale engine test with the actual fuels to evaluate the combustion system's response across a wide range of operating conditions. Engine acoustics are monitored continuously with Solar's burner acoustic monitor (BAM) system.

Hydrogen has a higher adiabatic flame temperature than natural gas and as a result the engine may emit higher NOx emissions depending on how the combustion system operates. For DLE systems that incorporate a pilot fuel circuit for added stability, a small increase in NOx emissions can occur as a result of the diffusion style or partially premixed style of pilot used in the injector design. Rig testing can usually accurately predict emissions in the engine for various fuels. However, since the rig is operated at scaled pressure compared to full load engine conditions, engine tests are needed for final confirmation of emissions levels (NOx, CO, UHC). In addition, the interrelation between combustion acoustics and emissions will be determined and the engine controls optimized for pilot level and combustion system temperature control.

One way to mitigate the additional NOx emissions is to use closed loop engine control based on the H2 content in the fuel. This control scheme takes advantage of the lower turndown capability with hydrogen that will allow reduced pilot settings and thus lower NOx emissions. In order to use this method, a reliable, low cost and fast acting sensor capable of determining the level of H2 in the fuel is required to be able to control the pilot fuel circuit in real time. Additionally, the fuel algorithm is dependent on the energy content of the fuel to minimize the flammability risk in the exhaust. Having a fast acting sensor to input the hydrogen content of the fuel will help mitigate operational risk. An evaluation of existing technology available will be included as part of the Pre-FEED study to be performed by the EPC with input from Solar Turbines.

A-3.2 Controls for Integrated Gas Turbine/Hydrogen systems

During the course of the design phase, systems engineering and trade-off analysis will be conducted to optimize the selection of the hydrogen production facility using energy from the main power block (supplemented by other microgrid and grid resources), hydrogen storage system and supporting components such as hydrogen compression and hydrogen piping. Components / systems at TRL 7 or higher will be considered for incorporation in the final design proposed for field demonstration. A reference design will be developed that uses only commercially available components (other than those within the turbine block described in the prior section). A key part of the trade-off analysis will be modeling of the dynamic operations of the system and subsystem to optimize the economics of the system including scenarios for different grid and microgrid services that may be provided.

A-3.2 System Optimization and Integrated System Design

The systems engineering and trade-off analysis and associated dynamic system modeling were described in the prior section. The integrated design will be validated via simulation and techno-economic modeling.

A-3.3 Exhaust Flameout and Re-Ignition mitigation

Hydrogen poses risks to gas turbine operation at start-up and during upset conditions where flameout can occur [4,5]. Although failed start attempts and combustion flameouts are upset conditions, they are not rare. When they occur and before the fuel supply is shut-off by controls, a charge of unburned fuel and air can enter the exhaust duct with a mixture that is above the lower flammability limit (LEL). For fuels containing hydrogen, the LEL is reduced significantly so that these type of trip events can potentially create flammable mixtures with hydrogen and natural gas blends, which would not be flammable with natural gas alone. If this charge ignites and combusts within the exhaust system a substantial pressure rise can develop that could cause moderate to severe damage in the exhaust system. The extent of the pressure rise depends on how the charge of fuel burns. The flame would start as a slow flame. Depending on the equivalence ratio, the influences of mixture temperature and the duct geometry would either cause the flame to stay in the slow flame regime, transition into a fast flame, or in the worst case a detonation wave. The magnitude of the pressure rise also depends on the fuel composition, equivalence ratio and initial temperature of the fuel-air mixtures; the length, size and shape of the duct; and obstacles in the flow path [5,6].

For the Titan 130 (T130) installed at UC Irvine operating on 30% Hydrogen by volume blended with natural gas, the fuel to air ratio in the exhaust will exceed the LEL but remain in the slow flame regime in the event of a flameout at full load. For existing gas turbine plants operating in the field, Solar Turbines has proposed the implementation of an exhaust air dilution system when required to lower the fuel to air ratio below the LEL to insure an un-ignitable mixture. The impact of the air dilution system has not been evaluated for operation with the waste heat recovery system. It is expected that it will have a detrimental impact on the performance. For this reason, Solar Turbines is proposing the investigation of a passive mitigation for exhaust over pressure in the event of re-ignition after a flameout. NFPA 68 Standard on Explosion Protection by Deflagration Venting outlines approaches for pressure release devices that provide safe venting and reduce the overall mechanical design requirements of the exhaust to contain such an event. The use of a deflagration venting system will allow the turbine to safely operate with exhaust levels that could exceed 100% of the LEL for the gas composition. Turbine controls will be optimized using the hydrogen fuel content signal to minimize exhaust LEL risk.

Further future effort would investigate the use of burst disks in the exhaust ductwork for up to 30% Hydrogen operation in the T130 with the UC Irvine waste heat recovery system design. The first step is to understand the magnitude of the pressure rise in the event of re-ignition after a flameout. This will be done by using a computational fluid dynamics model that is tuned for predicting pressure rises in turbine exhaust systems [5]. The intricacies of the flow path in the waste heat recovery system will need to be modeled to determine the impact on the propagation of the flame and resulting pressure wave. Simulations will then be run on the different operating scenarios, such as, duct firing on and off. The worst case pressure rise of the unvented deflagration will then be used as an input parameter for the design of the burst disk.

The key parameters for the design of the burst disk will include the exhaust geometry, maximum unvented pressure rise, the operating pressure of the system, and the design strength of the enclosure. The design process will yield a P-reduced value that is the maximum pressure the system will see in the event of a vented deflagration. If P-reduced is less than the design strength of the enclosure, then investigation of implementing the burst disk designs will proceed. If P-reduced is greater than the design strength of the enclosure, then an investigation into replacing a section of the system where the deflagration venting will occur with a strengthened duct will be the next step. Moving forward, Solar Turbines would work with a burst disk supplier and the EPC on the best methods for design and installation. The evaluation will include a risk analysis and implementation impact. As an intermediate deliverable could be a report outlining the evaluation of explosion protection by ventilation on the UC Irvine Gas Turbine and Waste Heat Recovery System.

A-4 Post-Project Plans

The Phase I effort, resulted in some preliminary plans for developing and conducting a field trial of the integrated gas turbine and hydrogen energy storage system. The Phase

I effort detailed the scope of changes and upgrades required, provide a project timeline and estimate of costs for implementing the plan on the UCI campus power plant utilizing the existing Solar Titan 130 gas turbine.

Follow on efforts would evolve the system to a point where designing and building a full scale system and for demonstration and system qualification on up to 30% hydrogen can be envisioned. Had possible follow-on efforts (1 year Pre FEED and a subsequent construction phase), an operational pre-commercial system could be demonstrated in a few years and potentially provide a pathway to commercial product offerings before 2030. Depending on the results of the overall system design trade-off analysis, the field demonstration may include some late-stage pre-commercial (e.g., commercial prototype) elements. Should such components be included in the design, the final technology maturation plan will address the steps to be taken to advance all components to TRL 9 by the end of the field demonstration. Interest remains in evolving the results of Phase I towards the field demonstration should resources and the opportunity arise.

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Appendix B—Technoeconomic Analysis

TECHNOECONOMIC REPORT

"Hydrogen Based Energy Storage System for Integration with Dispatchable Power Generation—Phase I Feasibility Study"

28 February 2022

US Department of Energy Contract FE-0032021

DE-FOA-0002332

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CAISO	California Independent System Operator
CP	Central Plant
GT	Gas turbine
HHV	Higher heating value
HRSG	Heat recovery steam generator
LCOE	Levelized cost of electricity
LMP	Locational marginal price
OASIS	Open Access Same-time Information System
NG	Natural gas
PV	Photovoltaics
SCE	Southern California Edison
ST	Steam turbine
T&D	Transmission and distribution

B-1 UCI Central Plant Layout and Operation

The UCI Central Plant (CP) is building around a 14.5 MW industrial gas turbine (GT). Heat from the GT exhaust stream is captured through a heat recovery steam generator (HRSG) and is used to meet campus heating loads and power a 5.5 MW steam turbine (ST). The CP also includes a cold-water production plant consisting of eight chillers totaling nearly 17,000 tons total cooling, and a cold thermal energy storage tank with 60,000 ton-hours of storage capacity. A schematic of all CP components is provided in Figure B-1.

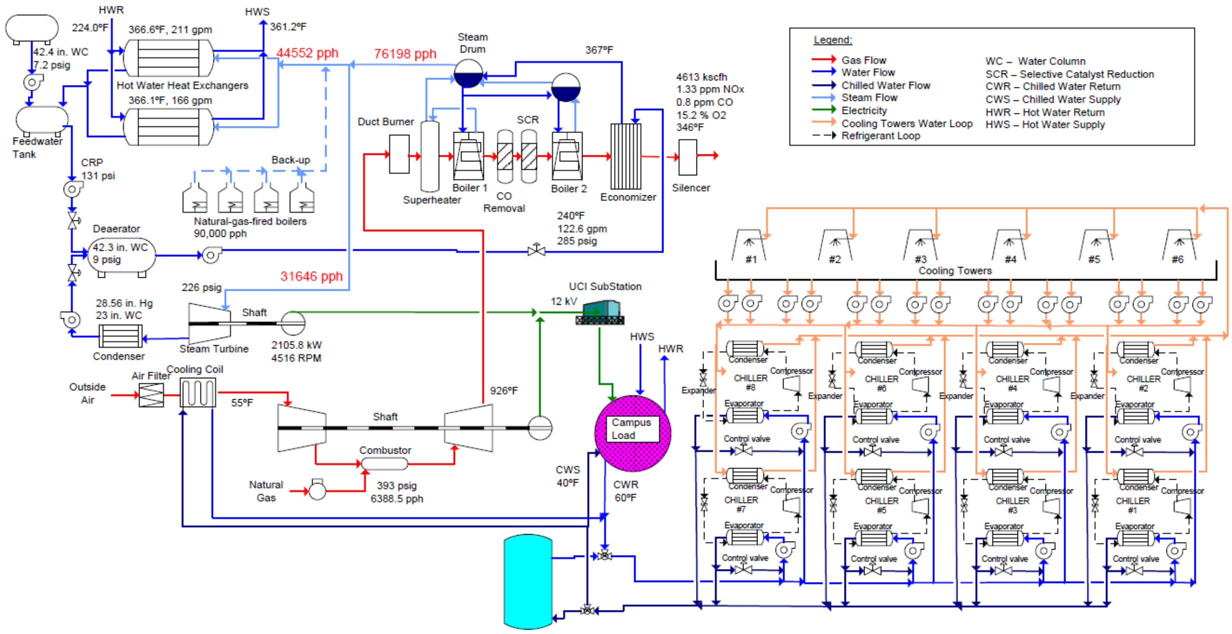

Figure B-1: A schematic showing the UCI central plant from [1], [2]. The plant consists of a 14.5 MW GT that produces steam. The steam is used to meet campus heating and steam loads through a district heating loop. The plant also includes eight chillers and a large cold thermal energy storage tank that meets campus cooling demand through a district cooling loop.

Aside from CP systems, approximately 4 MW of solar photovoltaics (PV) have been installed across the campus. Electricity from all solar PV systems is provided through power purchase agreements where the university is required to take all available solar production. Prior work has indicated that UCI solar PV potential is between 30 and 40 MW, depending on future building construction [3]. Based on this, the current work assumes that an additional 30 MW could be installed across the campus.

Current CP operations are based on a series of rules designed to reduce the cost of energy while meeting relevant contractual obligations. Based on conversations with CP operators, these rules include, but are not limited to:

1. Use all available solar PV production.
2. Prioritize using steam to meet campus heating demand over steam turbine operation.
3. Modulate the gas and steam turbines to minimize utility electrical import without exporting electricity (agreements with the electric utility allow for inadvertent export events. Extended periods of export will result in the forced tripping of the GT).

4. GT output must remain above 40% capacity to maintain stable lean combustion limits [4], [5]. Lean combustion occurs to limit GT pollutant emissions, which are strictly by the local air quality management district.
5. Aside from scheduled shutdowns for systems maintenance, the GT must always remain operational. This rule is also in place due to pollutant emission limits set by air quality regulators.

Prior work has described the extensive data collection system installed across the UCI campus [6]. Recent 2019 data from this system was captured and used to generate the load profiles used during in this work.

B-2 Optimization Formulation

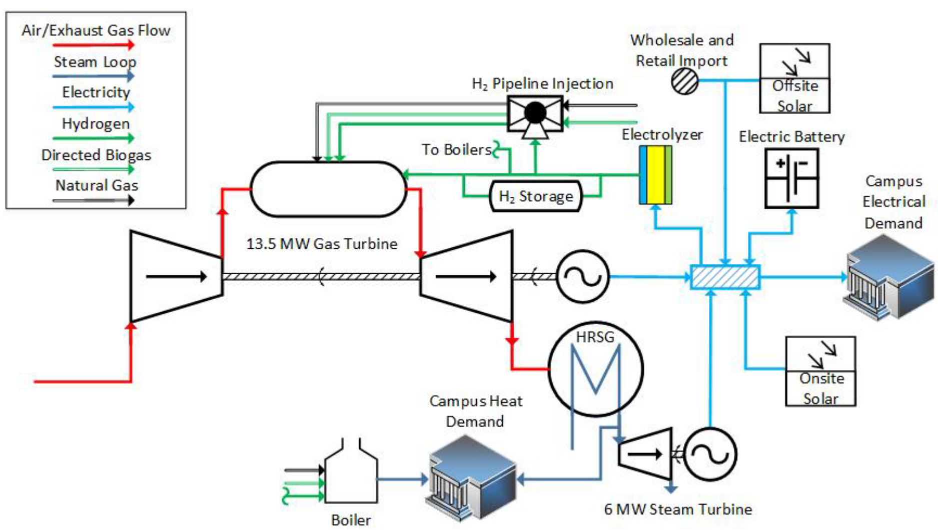

Figure B-2: CP and new H_2 components included in the system optimization. The primary focus of the formulation problem is on the campus electrical, hot water, and steam demand due to the potential impact of H_2 integration on how these end use loads are met.

B-3 DERopt Scenarios

Scenario development in this work is focused on examining current and future potential utility rate and tariff scenarios that govern modes of energy delivery and rates applicable to the university. Different technology options are examined within these utility scenarios (ex: maximum H_2 blend limit or ability to shut down and start up at will).

Sc1 – Current Rates: Scenario 1, or Sc1, uses current utility rates and rules. Currently, UCI is subject to several utility and service provider rates that govern energy generation, transmission and distribution, and standby/backup services. Electrical energy generation is procured by the UC system directly from California powerplants at a rate of $0.09 per kWh. Transmission and distribution services are provided by Southern California Edison (SCE), which charges UCI $0.02 per kWh according to a "direct access" rate. Standby and backup services are applied using a $12 per kW non-time of use demand. Demand charges are determined over 15-minute periods. Electrical utility connection occurs through two grid tied transformers with a total combined capacity of approximately 50 MW.

Natural gas rates are negotiated directly with suppliers and are typically less than $0.60 per therm HHV. The UC system has or is developing a series of directed biogas projects to aid decarbonization efforts. Current gas allocations provide UCI with 491,265 therms of directed biogas per year at a cost of $1 per therm ($0.60 per therm directly to gas suppliers and $0.40 per therm for directed biogas premium). Finally, H_2 production and storage must occur onsite as pipeline injection is not currently allowed.

For UCI to operate the current GT engine while maintaining a grid connection, SCE requires UCI to pay a "departing load" charge of approximately $0.02 per kWh. This charge is applied to all electrical energy generated by the GT and ST.

Sc2 – Decarbonized Electric Procurement: Scenario 2, or Sc2, is the same as Sc1 with one exception – the campus can contract directly with in-state, utility scale power plants. This option allows for UCI to decrease the cost of procured electricity from $0.09 per kWh to less than$0.03 per kWh while also accessing zero carbon electricity. However, campus import must match utility scale solar PV production, or the campus must finance a utility scale battery to support the shifting of solar PV production. A transmission and distribution charge of $0.02 per kWh still applies. This scenario enables access to lower cost renewable electricity for use across the UCI campus, including for use in H_2 production. Utility scale solar profiles were generated using the NREL PVWatts calculator [7] for a 1-D tracking solar panel located in the California Central Valley, achieving a capacity factor of 28%.

Sc3 – Future LMP Access: Scenario 3, or Sc3, is designed to examine one potential future scenario where the campus has gained the ability to purchase electrical energy on the local wholesale market. This allows for the campus to purchase energy day-ahead locational marginal price (LMP). LMP price data from 2019 for the SCE Santiago Substation were captured from the California Independent System Operator (CAISO) Open Access Same-time Information System (OASIS) [8]. A summary plot of this LMP data is shown in Figure B-3. This left figure shows the median LMP day ahead electricity price and the price range between the 5% and 95% price percentiles. The right figure shows the price duration curve for the Santiago node, showing the price primarily oscillating between $0 and $80 per MWh while reaching extreme price levels for short durations.

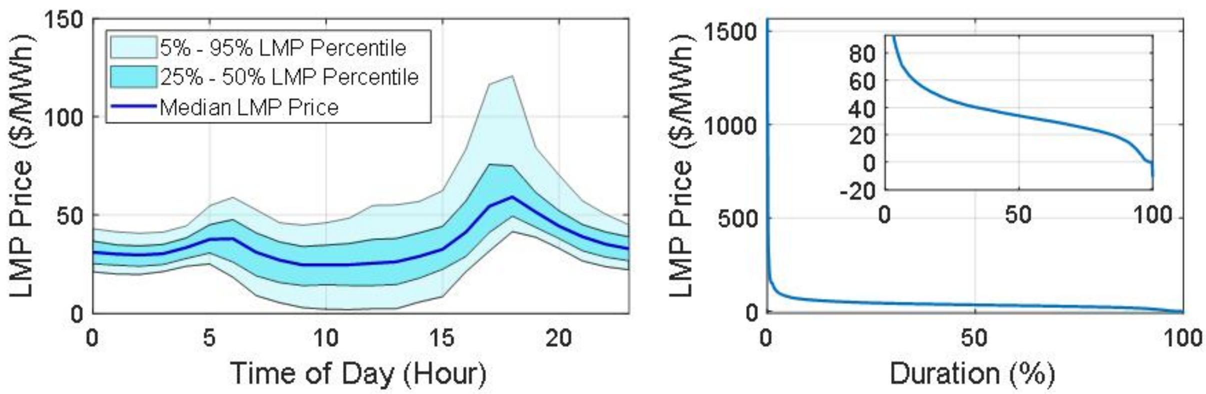

Figure B-3: Summary of the Santiago LMP day ahead price for wholesale electricity in 2019. The left plot shows the average LMP price versus hour of day along with percentile ranges from 5% to 95%. The right plot shows the price duration curve for the Santiago node where the price ranges from $1,570 to -$11 per MWh, but averages $40 per MWh.

It is assumed that all directed biogas contracts have expired and were not renewed and that departing load charges applied to onsite generation have expired.

Sc4 – Future Increased Electricity Costs: Scenario 4, or Sc4, assumes that UCI does not gain access to LMP day ahead electricity prices. Instead, Sc4 assumes that the cost of electric energy increases to $0.18 per kWh, based on initial analysis on the cost of achieving a net zero carbon electric grid in California [9]. T&D, standby, and backup charges continue to apply. Sc4 assumptions on directed biogas and departing load charges are the same as Sc3. This scenario, however, does allow for the offsite production and delivery of H_2 using gas utility pipelines at a cost of $0.20 per therm HHV. Since current directed biogas contracts include out-of-state resources, it is assumed that an offsite H_2 production plant can be sited to provide access to both high quality solar and wind resources. Available wind resources were based on wind data taken from the NREL Wind Prospector tool [10] taken for Tehachapi Pass, California. Wind data was converted to time resolved electricity production using the vertical axis wind turbine design process described in [11] using a design wind speed of 13 meters per second, a cut in and out windspeed of 5% and 150% design wind speed, and an overall turbine efficient of 80% the Betz limit.

B-4 Results

The following section presents results produced by DERopt when evaluating lowest cost energy technology adoption and operation to achieve lowest cost. Since the general goal of this work is to determine the lowest cost method for decarbonizing campus energy supply, DERopt was used to evaluate optimal technology adoption and operation as emissions were reduced from current emission levels to zero emissions. Each scenario was tested under two engine scenarios: 1) the GT must always remain operational due to pollutant emission constraints, and 2) the GT can shut down and start up at any time. Additionally, Sc1 includes a series of tests that evaluate the GT with different H_2 tolerances ranging from the current engine limit of 30% H_2 by volume, up to 100%.

Since all results are compared against a "baseline" scenario, Section B-4.1 defines baseline operation and the associated carbon emissions and cost of energy. This section also establishes the validity of the DERopt results versus current UCI CP operations. Subsequent sections provide results for all utility rate and tariff scenarios. The general set of results of this work can be summarized as following: In an effort to decarbonize the UCI campus, it is more cost effective to shut the current GT engine off and meet campus electric loads using the electric grid. The one instance where this result changes is when imported electricity increases in price and the campus can receive directed renewable H_2 that is generated offsite and injected into gas pipelines.

B-4.1 Baseline Operation

Baseline operation is defined as lowest cost operation without any carbon constraints. Baseline operation for the UCI CP is shown in Figure B-4. These results are representative of all four scenarios Sc1 through Sc4. Regardless of scenario, the lowest cost form of energy available to the campus is through the GT fueled using conventional natural gas. The operating rules described in Section 0 are captured generally captured through the optimization model, indicating that current operation of the GT/ST system is near optimal. An example of winter and summer optimal operation is shown in Figure B-4. This figure shows electrical generating assets in the top row and heat generating assets in the bottom row. Both winter and summer week results show that the gas turbine fueled exclusively using conventional natural gas is used to meet nearly all campus electrical demand. In the winter, heat produced from the gas turbine is captured and used to meet campus heating load, resulting in minimal steam turbine operation. Campus heating demand peaks during winter mornings, and boiler operation is required to meet peak thermal demand.

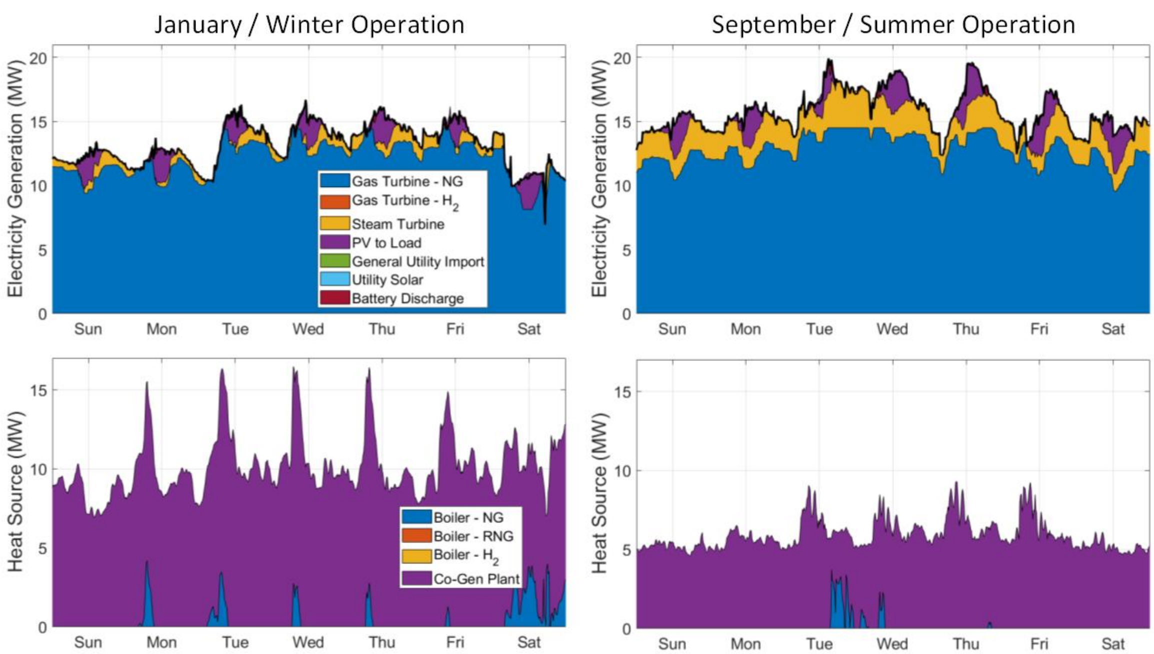

Figure B-4: Examples of optimal CP operation during a winter and summer week. X-tick marks indicate noon for each day. Top row figures show how electric generating assets can be optimally operated to meet campus electrical demand. Top row figures show the corresponding operation of boiler systems and heat production from the cogeneration system to meet campus heat demand. The primary difference between winter and summer operation is the heating load, which is predictably larger in the winter. The larger winter heating load requires most of the steam produced by the cogeneration system, limiting steam turbine

operation. Conversely, summer heating requirements are lower, allowing for more continuous steam turbine operation.

Cooling demand in late summer months (September) results in peak electrical demand at or after midday. Heating demand during this period of operation is driven by 1) district heating system supply and return temperature requirements, 2) HVAC reheat, and 3) laboratory hot water and steam demand. Minimal building heating is required, leaving excess steam available for use in the steam turbine. Figure B-4 shows gas and steam turbine operation being modulated to accommodate all available solar PV generation while minimizing utility imports.

Note that optimal summer operation results in the firing of a boiler at noon on Tuesday. This operation is driven by the coincident of near-peak electrical demand. Instead of reducing ST output to direct steam to meeting campus heating demand, lowest cost is achieved by firing CP boiler systems. CP operators do not typically operate boiler systems in the summer, and this type of summertime operation is not observed in CP data.

According to optimization results, onsite energy assets can meet all campus heating demand and 99.995% or campus electrical demand, achieving a total levelized cost of electricity of $0.05 per kWh. This exceptional result is a product of the optimization process, which contains perfect knowledge of all campus energy demand across the considered year, is not bound by typical CP rules that restrict certain operations (e.g., boiler operation in the summer), and can eliminate virtually all utility electrical import without exporting any electricity. Aside from these caveats, the optimal operation results produced by the model typically match actual CP operations and establish a baseline cost of energy and carbon emissions to be used when examining the integration of H_2 systems. On an annual basis, energy procurement results in the release of 60,840 tonnes CO_2 per year. Since utility import is minimized, this baseline carbon emissions value is applicable to all scenarios. Using the assumed conventional natural gas cost, the levelized cost of electricity (LCOE) across the campus is $0.08 per kWh. Dropping the departing load charge of $0.02 per kWh reduces campus LCOE to $0.06 per kWh.

B-4.2 Sc1 – The Value of Increasing Engine H_2 Limits

Sc1 is used to examine the value of 1) using a 100% H_2 engine, and 2) the value of H_2 towards decarbonizing the current UCI system. The optimization model was used to minimize total cost of energy while reducing carbon emissions from the baseline value of 60,840 tonnes CO_2 per year. Engine H_2 limits were varied from 30% to 100% H_2 by volume. When testing different H_2 limits, the engine was forced to remain on at all hours. After testing the 100% H_2 engine, a subsequent set of simulations were run where the engine was allowed to shut down and start up any time.

Under current utility rules, the optimization model shows that carbon emissions can only be reduced by 70% to 80% from baseline. Further reductions require expanded access to zero carbon resources and/or the consideration of other clean energy technologies. Optimal technology adoption for all engine configurations tested under Sc1 are shown in Table B-1. Entries for infeasible scenarios (ex: 30% H_2 engine at or beyond a 75% CO_2 reduction are left empty. Technology adoption results are enhanced through understanding of how electricity and fuel is used across the campus. Electricity and fuel source results for the 30% and 80% H_2 engines, and the 100% H_2 engine that is allowed to shut down and start up is shown in Figure B-5. The 50% and 100% H_2 GT scenarios are excluded due to brevity and to the 30% and 80% GT scenarios.

Table B-1: Optimal technology adoption for all engine scenarios captured in Sc1. Infeasible scenarios have no entry (ex: 30% H_2 engine at a 75% CO_2 reduction)

New Solar PV (MW)					
CO_2 Reduction (%)	30% H_2 Engine	50% H_2 Engine	80% H_2 Engine	100% H_2 Engine	100% H_2 Engine + On/Off
Baseline	0	0	0	0	0
10%	0	0	0	0	0
25%	0	0	0	0	0
50%	8.0	8.0	8.0	8.0	8.0
60%	20.6	20.6	20.6	20.6	20.6
65%	30	30	30	30	8.0
67.5%	30	30	30	30	8.0
70%	30	30	30	30	8.0
72.5%	30	30	30	30	8.8
75%		30	30	30	20.4
77.5%		30	30	30	30
80%				30	30

Battery Energy Storage (MWh)					
CO_2 Reduction (%)	30% H_2 Engine	50% H_2 Engine	80% H_2 Engine	100% H_2 Engine	100% H_2 Engine + On/Off
Baseline	0	0	0	0	0
10%	0	0	0	0	0
25%	0	0	0	0	0
50%	6.0	6.0	6.0	6.0	6.0
60%	19.3	19.3	19.3	19.3	19.3
65%	35.1	30.9	18.2	18.2	0
67.5%	55.2	25.0	13.2	5.2	0
70%	93.1	45.2	17.2	0.4	0
72.5%	160.9	75.3	23.2	8.4	0.8
75%		117.8	46.7	44.6	11.9
77.5%		191.9	103.9	93.6	41.4
80%				151.8	129.2

Electrolyzer (MW)					
CO_2 Reduction (%)	30% H_2 Engine	50% H_2 Engine	80% H_2 Engine	100% H_2 Engine	100% H_2 Engine + On/Off
Baseline	0	0	0	0	0
10%	0	0	0	0	0
25%	0	0	0	0	0
50%	0	0	0	0	0
60%	2.2	2.2	2.2	2.2	2.2
65%	7.0	7.1	8.4	8.4	0
67.5%	11.9	12.4	12.0	13.1	0
70%	20.4	17.7	17.1	18.3	0
72.5%	33.9	24.9	22.6	21.9	0
75%		35.4	28.1	25.9	0
77.5%		49.8	37.8	35.2	0
80%				64.7	0

H_2 Energy Storage (MWh)					
CO_2 Reduction (%)	30% H_2 Engine	50% H_2 Engine	80% H_2 Engine	100% H_2 Engine	100% H_2 Engine + On/Off
Baseline	0	0	0	0	0
10%	0	0	0	0	0
25%	0	0	0	0	0
50%	0	0	0	0	0
60%	0	0	0	0	0
65%	34.9	15.0	0	0	0
67.5%	69.6	53.6	0.7	0	0
70%	142.1	92.1	37.2	0	0
72.5%	367.4	154.7	84.6	1.5	0
75%		303.6	133.1	31.5	0
77.5%		1349.7	195.0	122.6	0
80%				349.4	0

The optimization model produces three distinct approaches for reducing carbon emissions. All scenarios show that emissions are reduced by up to 50% through a combination of directed biogas, increased utility imports that offset GT output. Electric imports occur during periods when electric grid carbon intensity is low (i.e., middle of the day when utility solar is peaking). Emissions can be reduced further through the expansion of onsite solar PV and battery energy storage systems, and the adoption of a 2 MW electrolyzer. Beyond 60% requires the adoption of additional technology and modifications to how the GT is operated.

For the scenarios where the GT must remain on, carbon emissions are reduced further by maxing out onsite solar PV, adopting a progressively larger electrolyzer system, and increasing both battery electric and H_2 storage systems. GT output is minimized while H_2 production increases, reducing the amount of conventional fuel that must be offset. Due to limited onsite solar PV potential, the electricity needed to make H_2 is purchased from the local utility.

For the single scenario where the GT is allowed to shut down and start up, lowest cost is achieved by ceasing GT operation during the entire simulation. A combination of utility imports and onsite solar PV are used to meet campus electrical demand and directed biogas is combusted in CP boiler systems to meet campus heat demand. Under this scenario, adopted battery size is smaller than comparable engine scenarios that require constant operation and total fuel combustion occurring on campus drops by over 70% on an energy basis.

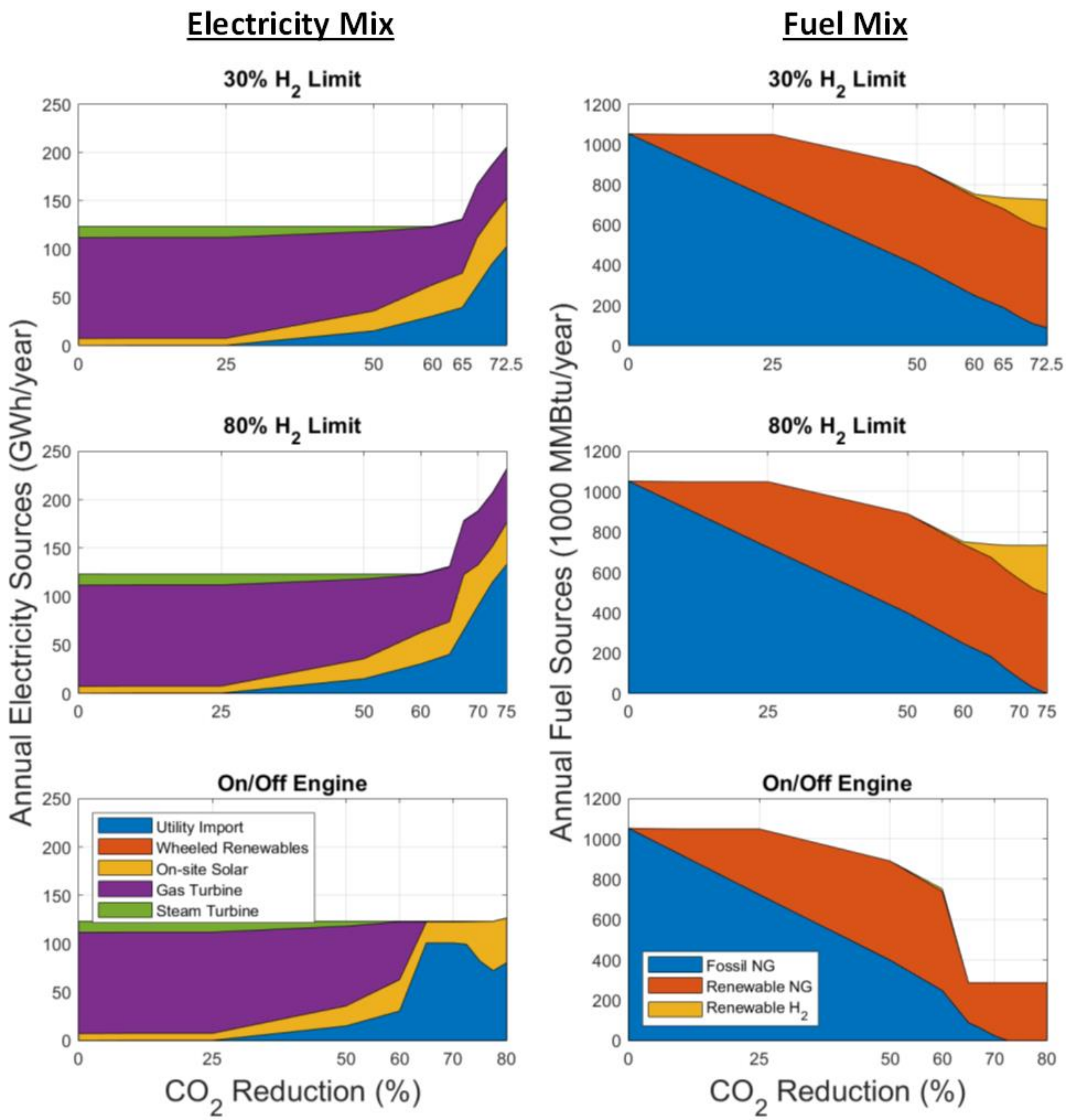

Figure B-5: Electricity and fuel mix when CP equipment and operation are modified to minimize cost of energy while reducing carbon emissions. The top and middle row of figures show optimal energy mixes when engine H_2 fraction is limited to 30% and 80% by volume and the engine is required to remain operational due to pollutant emission regulations. The bottom row shows the optimal energy mix with a 100% H_2 engine that is allowed to turn on and off during any hour in the simulation.

The levelized cost of electricity (LCOE) for these simulation results are shown in Figure B-5. This figure shows LCOE results for a 50% reduction and beyond due to all simulations producing similar results at emission reductions below 50%. These results demonstrate two critical contrasts. First, the results show that, when CO_2 reduction level is held constant, LCOE is lower when engine H_2 potential is increased. The second contrast is the steep decrease in cost when the engine is allowed to shut down. These results indicate that the cost of decarbonizing GT operation is significantly higher than the cost of shutting the engine down and importing all electricity from the grid.

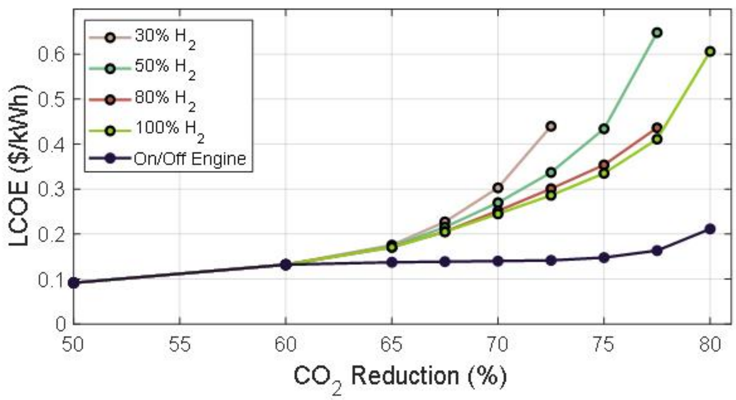

Figure B-6: Levelized cost of electricity for all simulations captured in the Sc1 scenario. The results show that LCOE is reduced when GT H_2 fuel fraction is increased. However, the results also show that, under current utility rules and rates, the lowest cost option for decarbonizing the UCI campus with the technologies and options considered in this work is to shut the engine off, expand onsite solar PV and battery electric storage systems, and import remaining electricity from the grid.

Three examples of optimal CP operation are shown in Figure B-7 for when carbon emissions are reduced by 70%. Results are shown for the same summer week as shown in Figure B-4.The figure shows electricity generation (left column) and load (right column). Engine scenarios match those shown in Figure B-5 (30% and 80% H_2 engine that always remains operational, and a 100% H_2 engine that can shut down and start up).

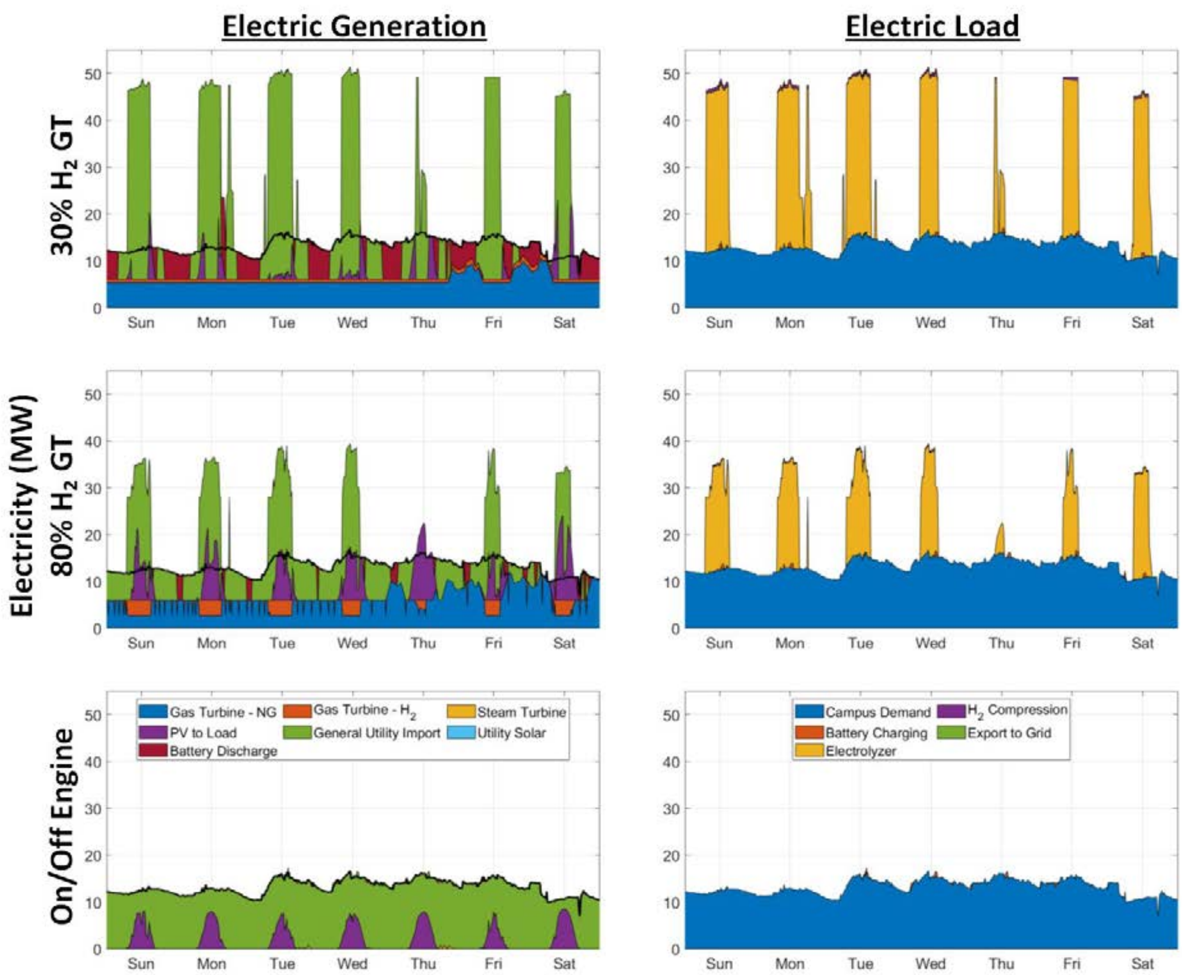

Figure B-7: An example of optimal operation when reducing carbon emissions by 70% during a summer week for Sc1. Engine scenarios match the same scenarios included in Figure B-5, or when using a GT capable or 30% H_2 and 80% H_2,and operating all hours of the simulation, and 100% H_2 when the GT can be shut down and started up. The acronym NG in "Gas Turbine – NG" stands for natural gas

Results for both constant operation engine scenarios show GT operation at or near the minimum 6 MW load setting for most hours except for Thursday, Friday, and Saturday night. In both instances, midday utility imports (shown in green) are used to power an electrolyzer. Note, however, a difference in H_2 delivery to the two engine scenarios. The 30% H_2 engine receives a steady natural gas and H_2 mixture while most of the H_2 in the 80% scenario is injected into the engine as it is produced. The two key factors driving this result are that 1) the engine cannot be shutdown, creating a constant gas load that must be decarbonized, and 2) a constant conventional natural gas and directed biogas carbon intensity. These factors result in the selection of the presented operational results.

The import of 20 to 30 MW of utility electricity to make sufficient H_2 to generate up to 5 MW of electricity is clearly suboptimal from a resource management perspective. As a result, when allowed to shut the GT down, the model selects to cease engine operation, expand onsite solar PV, and meet all electricity shortfalls using utility imports. This solution results in the maximum carbon reduction possible at the lowest cost given the utility and technology options considered under current utility rates.

B-4.3 Sc2 – Expanding Renewable Energy Access

One potential reason for the limited role of H_2 in decarbonizing Sc1 is a lack of low-cost renewable energy. Although onsite solar PV assets are limited, the UC system can contract with or develop utility scale renewable power plants in order to develop a clean, offsite source of electricity. Sc2 is used to explore this scenario. Under this scenario, the campus can import electricity under the prior $0.09 per kWh rate, or from a new offsite solar and battery electric storage powerplant. If offsite renewable resources are expanded, export from the new powerplant must coincide with campus electric imports. Sc2 is exercised for two engine scenarios: 1) engine always on and 2) engine can shut down and start up (engine on/off). Under this scenario, emissions can be reduced by nearly 100%. However, reducing emissions from 95% to 100% doubles the cost of energy[20], so results are presented up to a 95% reduction only.

Technology adoption results for Sc2 are shown in Table B-2. On-campus solar PV and battery energy storage systems were not adopted in any simulation and are omitted from Table B-2. The corresponding electrical and fuel energy mix for the two engine scenarios is shown in Figure B-8 (electric imports from any new offsite renewable powerplant are plotted using the orange-red color and are labeled “Wheeled Renewables”.)

[20] At a 95% carbon reduction, remaining emissions stem from the use of directed biogas. Due to the low carbon emission to energy content ratio, decarbonization of directed biogas with renewable H_2 is far more resource intensive than decarbonization of conventional natural gas. In this instance, it is likely more cost effective to find ways to reduce carbon emissions associated with the production of directed biogas. This step, however, is not considered in the current work.

Table B-2: Optimal technology adoption for all engine scenarios captured in Sc2.

CO_2 Reduction (%)	Utility Solar (MW)		Utility Battery Storage (MWh)		Electrolyzer (MW)	
	Engine Always On	On/Off Engine	Engine Always On	On/Off Engine	Engine Always On	On/Off Engine
Baseline	0	0	0	0	0	0
10%	8.6	8.6	0.3	0.3	0	0
25%	8.6	8.6	0.3	0.3	0	0
50%	12.8	12.8	3.9	3.9	0	0
60%	26.9	26.9	84.5	84.5	0	0
65%	36.7	36.7	117.2	117.2	1.3	1.3
67.5%	41.4	26.7	128.5	27.4	2.6	0
70%	46.4	26.7	133.6	27.4	4.5	0
72.5%	51.3	26.7	136.6	27.4	6.6	0
75%	56.6	26.7	139.0	27.4	8.6	0
77.5%	62.0	26.7	140.7	27.4	10.7	0
80%	67.5	31.4	140.9	53.7	12.9	0
85%	78.6	47.2	142.7	150.1	17.3	0
90%	90.0	72.3	143.1	228.2	21.6	0
95%	155.3	120.8	168.1	306.9	38.5	6.8

In general, Sc2 results mirror Sc1. Carbon emissions are initially reduced through the use of directed biogas. Due to the availability of lower cost renewable electricity through offsite solar, solar PV capacity is installed when emissions are reduced by as little as 25%. Emission reductions beyond 50% mirror Sc1 where solar, storage, and electrolyzer assets are expanded when the engine remains on. Allowing for the engine to be shutdown leads to a cease in GT operations at around a 60% carbon reduction. The lost generation is offset through increased utility imports coming from both the general utility and an expanded, dedicated renewable powerplant.

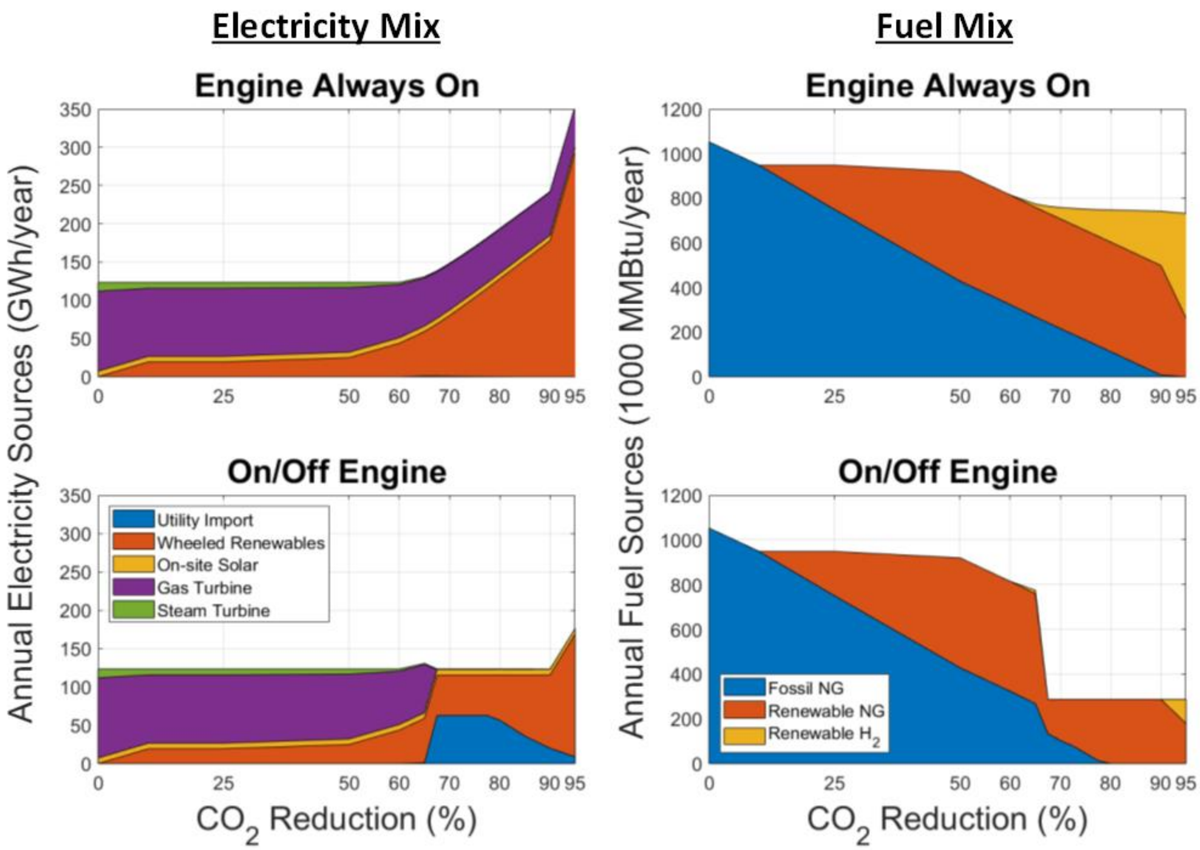

Figure B-8: Electricity and fuel mix when CP equipment and operation are modified to minimize cost of energy while reducing carbon emissions. The top row of figures show optimal energy mixes when an 100% H_2 capable engine is required to operate at all hours. The bottom row of figures shows optimal energy mixes then the same engine is allowed to shut down and start up during any part of the simulation.

Note that use of H_2 occurs under the GT On/Off scenario when emissions are reduced from 90% to 95%. This result is driven by efforts to decarbonize campus heating through replacement of directed biogas in CP boiler systems with renewable H_2.

The corresponding LCOE is shown in Figure B-9. These results mirror Sc1 LCOE results, showing that lowest cost is achieved when ceasing GT operation. Despite differences in technology options, optimal CP operations mirror Sc1 results where H_2 is injected directly in the GT. In this instance, H_2 storage systems are not adopted since GT fuel requirements are sufficient to consume all H_2 as it is produced.

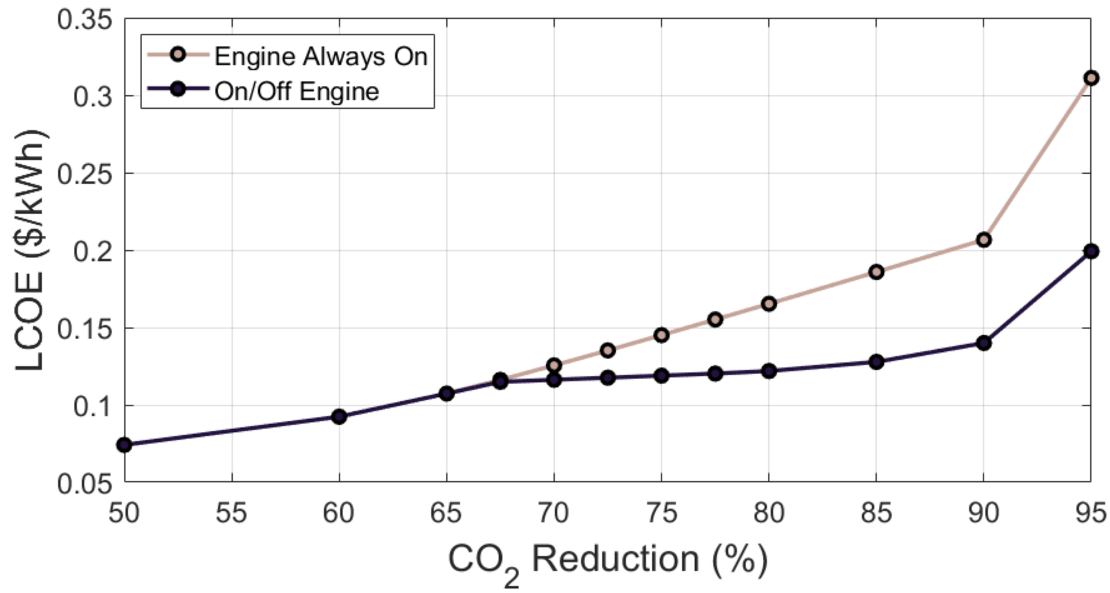

Figure B-9: Levelized cost of electricity for all simulations captured in the Sc2 scenario. Comparing these results to the LCOE values obtained in Sc1 clearly show that developing access to low cost renewable electricity has tremendous cost benefits. Similarly, these results show that cost of energy is lower when the GT is shut down and the development of onsite H_2 resources is avoided.

B-4.4 Sc3 – Removing Directed Biogas

Results from Sc1 and Sc2 both show that access to low cost directed biogas is key to deep decarbonization across the UCI campus. Considering that this resource potential is small relative to historical natural gas demand [12], results for Sc1 and Sc2 are not extensible. Sc3 explores a scenario where UCI does not have access to directed biogas. Sc3 also assumes access to wholesale electricity prices. However, this access has similar value to offsite solar PV considered in Sc2 and Sc3 unless paired with the decarbonization of utility electricity. Likewise, access to offsite renewable electricity is necessary for developing deep decarbonization options that do not automatically result in GT shut down. Considering onsite solar PV potential only, the optimization model becomes infeasible after reducing carbon emissions by 25% unless shut down is allowed. As with Sc2, Sc3 was examined considering a 100% H_2 engine that remains on and a 100% H_2 engine that shut down and start up.

Sc3 technology adoption is shown in Table B-3. The corresponding energy mix and LCOE for Sc3 are shown in Figure B-10 and Figure B-11 respectively. Although a 100% carbon emission reduction is possible under Sc3, equipment costs become unreasonable beyond a 90% reduction for the engine always on scenario, and 95% for the on/off engine scenario. For example, LCOE approaches $0.90 per kWh when reducing carbon emissions by 99% and engine operation is required.

Table B-3: Optimal technology adoption for all engine scenarios captured in Sc3.

CO_2 Reduction (%)	Utility Solar (MW)		Utility Battery Storage (MWh)		Electrolyzer (MW)		H2 Storage (MWh)	
	Engine Always On	On/Off Engine	Engine Always On	On/Off Engine	Engine Always On	On/Off Engine	Engine Always On	On/Off Engine
Baseline	6.4	6.4	7.4	7.4	0	0	0	0
10%	13.8	13.8	18.0	18.0	0	0	0	0
25%	34.9	34.9	116.5	116.5	0.3	0	0	0
50%	84.6	71.9	152.5	223.5	19.1	0	0	0
60%	119.1	71.9	199.5	223.5	24.2	0	27.5	0
65%	136.4	71.9	292.3	223.5	24.8	0	35.8	0
67.5%	144.6	71.9	348.5	223.5	25.0	0	38.2	0
70%	154.4	87.2	403.7	246.4	25.1	0.6	39.7	0
72.5%	163.9	90.7	462.9	256.7	25.2	2.1	41.1	0
75%	175.1	94.3	519.2	265.9	25.2	3.7	41.6	0
77.5%	190.9	100.0	566.5	279.7	25.2	5.4	41.8	0
80%	214.2	107.5	607.6	296.4	25.1	6.9	41.2	2.3
85%	270.4	124.4	727.7	300.7	25.7	11.0	41.6	41.7
90%	349.9	167.0	885.3	303.7	27.5	17.7	46.7	73.5

Simulation results mirror Sc2 after directed biogas has been fully utilized. Emissions can be reduced slightly through the initial adoption of offsite solar. However, when engine operation is required, H_2 equipment adoption begins at emission reduction levels as low as 25%. Simulation results show that requiring the engine to operate increases total electricity use across the campus by nearly 400%, driven by renewable H_2 production. Conversely, if the engine is allowed to shut down and start up, GT operations cease when emissions are reduced by more than 25%.

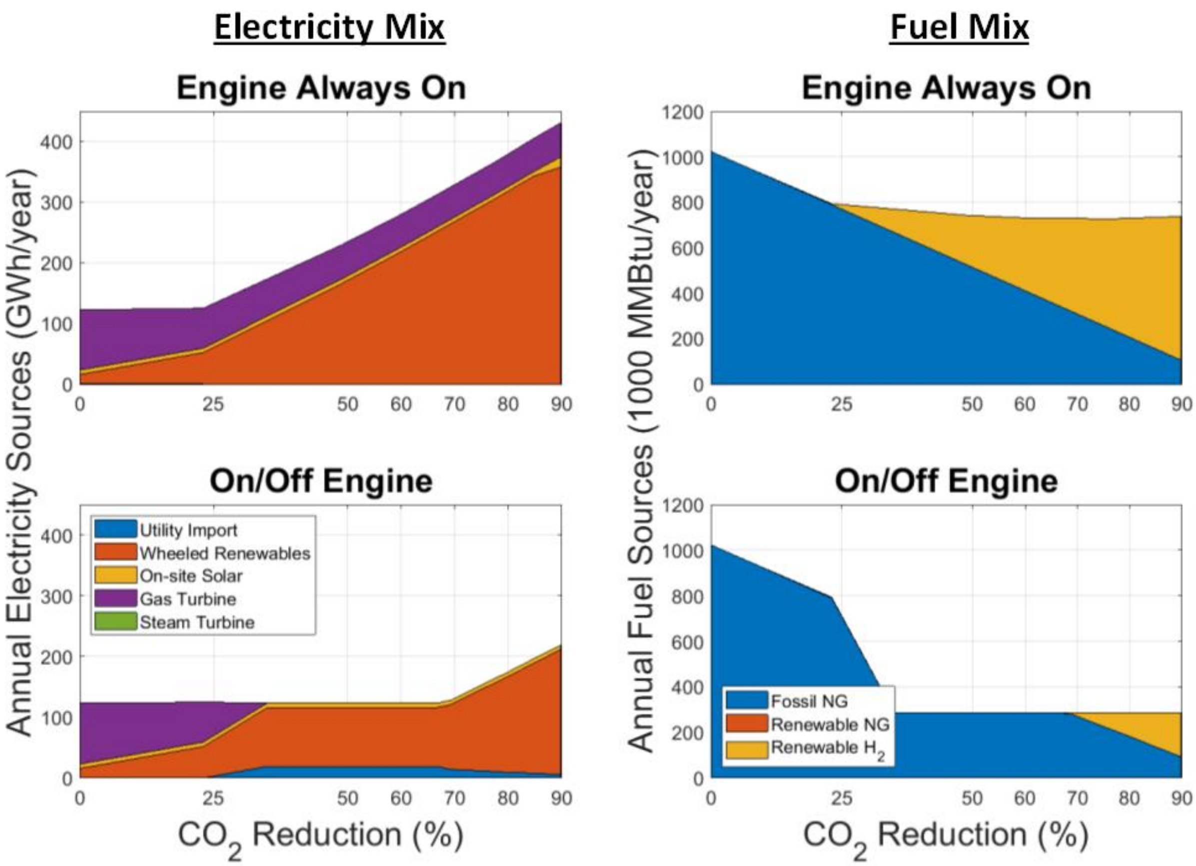

Figure B-10: Electricity and fuel mix when CP equipment and operation are modified to minimize cost of energy while reducing carbon emissions under Sc3. The top row of figures show optimal energy mixes when an 100% H_2 capable engine is required to operate at all hours. The bottom row of figures shows optimal energy mixes then the same engine is allowed to shut down and start up during any part of the simulation.

When GT operation ceases, a 70 MW solar PV and 240 MWh battery energy storage power plant is adopted and used to provide campus electricity. This step results in a 70% emissions reduction, with the remaining 30% originating from the use of conventional fuel to meet campus heating demand. Further reductions are achieved only through H_2 production, resulting in the expansion of renewable energy systems and the adoption of an electrolyzer and H_2 storage system.

LCOE results, shown in Figure B-11, mirror Sc1 and Sc2 where shutting the GT down during the entire simulation leads to lower cost of energy. Although LCOE always increases when reducing carbon emissions, a steep increase in cost is observed under the on/off engine scenario when H_2 is produced to offset conventional natural gas.

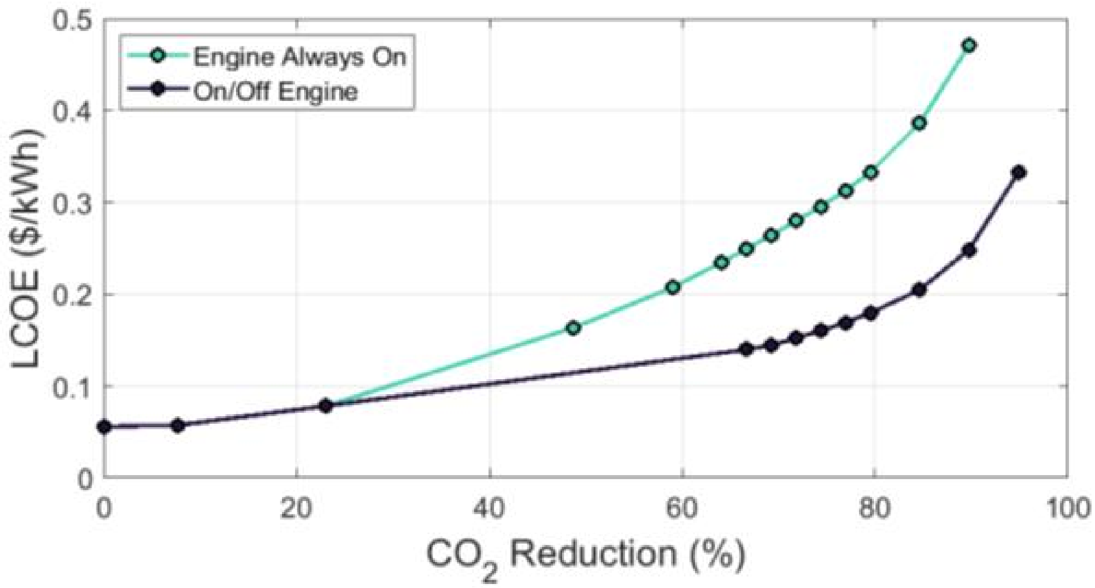

Figure B-11: Levelized cost of electricity for all simulations captured in the Sc3 scenario.

B-4.5 Sc 4 – Offsite H_2 Production

Sc3 results indicate that direct use of low-cost renewable electricity is preferrable that H_2 production. Sc4 examines a separate potential pathway where the cost to generate, transmit, and distribute electricity increases versus current rates. Additionally, this scenario allows for the remote production of H_2 and injection into the State gas network.

This scenario was tested with both an engine required to remain operational and an engine that can shut down and start up at any moment. Unlike all other prior scenarios, there is no difference in optimization results between these two engine scenarios. The results indicate that, under this scenario, optimal operation is achieved when the GT remains operational. Table B-4 shows optimal technology adoption for Sc3 across the different levels of carbon reduction. Results indicate that onsite solar is initially expanded to nearly 11 MW, but subsequent carbon reductions are achieved with the adoption of 6.7 MW onsite solar paired with offsite H_2 production powered using wind resources. The corresponding campus energy mix is shown in Figure B-12. This figure shows the onsite energy mix, how offsite renewable electricity was used, and the onsite fuel mix. In all previous scenarios, offsite renewable electricity was always delivered towards the campus, eliminating the need to differentiate between how onsite and offsite electricity was used.

Table B-4: Optimal technology adoption for all engine scenarios captured in Sc4. Offsite H_2 injection capacity was found to always equal offsite electrolyzer capacity and is omitted from this table.

CO_2 Reduction (%)	Onsite Solar (MW)	Onsite Battery Storage (MWh)	Offsite Wind (MW)	Offsite Solar (MW)	Offsite Electrolyzer (MW H_2)
Baseline	0.8	1.1	0	0	0
10%	10.6	6.9	0.1	0.2	0.2
25%	6.7	3.6	26.3	0	15.8
50%	6.7	3.6	61.0	0	36.6
60%	6.7	3.6	74.9	0	44.9
65%	6.7	3.6	81.8	0	49.1
67.5%	6.7	3.6	85.3	0	51.2
70%	6.7	3.6	88.7	0	53.2
72.5%	6.7	3.6	92.2	0	55.3
75%	6.7	3.6	95.7	0	57.4
77.5%	6.7	3.6	99.1	0	59.5
80%	6.7	3.6	102.6	0	61.6
85%	6.7	3.6	109.5	0	65.7
90%	6.7	3.6	116.5	0	69.9
95%	6.7	3.6	123.4	0	74.0
99%	5.4	2.4	130.5	0	78.3

Note that the offsite electrolyzer is sized exactly to adopted solar and wind resources, converting all available electricity to hydrogen. Additionally, no offsite H_2 storage is adopted, meaning that all H_2 is injected into the pipeline as soon as it is produced. H_2 injection rates peak at 0.65 kg injected per second (or 2.34 tonnes per hour) in order to support a 99% carbon onsite carbon reduction. At this level of carbon reduction, the campus requires 9.4 thousand metric tons of H_2 per year. The amount of electricity required to produce this level of H_2 is 4.1 times more than annual campus electricity usage.

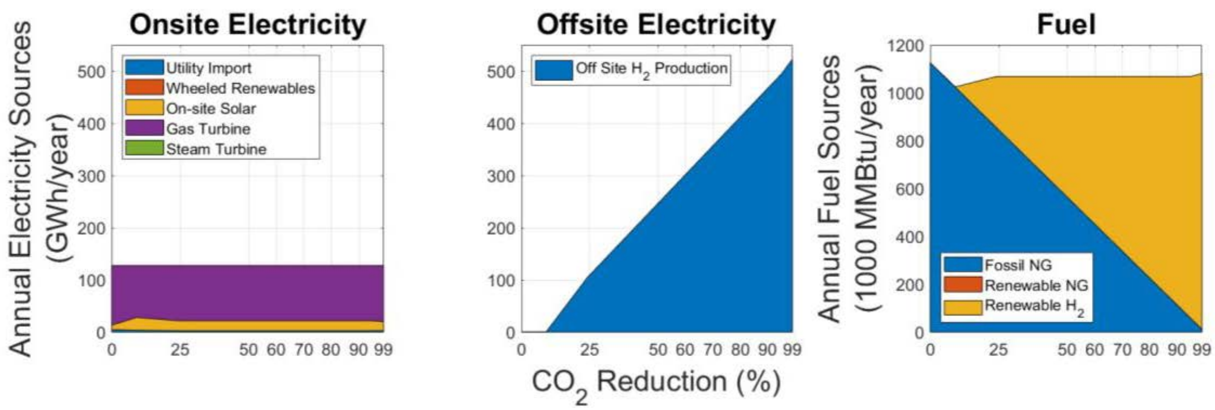

Figure B-12: Energy and fuel mix for Sc4. Results show onsite electricity sources, amount of offsite electricity used to generate H_2 used in campus operations, and the fuel mix.

These results show that the mix of onsite resources remains relatively constant throughout all carbon reduction levels. Onsite assets remain fixed since the primary method for decarbonization is found to be the expansion of offsite H_2 production potential, resulting in the eventual offsetting of all natural gas with renewable H_2. In total, over 9.4 thousand tonnes H_2 per year are required to decarbonize UCI operations.

Since offsite resources are exclusively used to produce hydrogen, the levelized cost of hydrogen can be calculated directly by dividing the capital and operations costs associated with offsite energy systems by total H_2 production. This yields a cost ranging from $2.65 per kg at a 10% carbon reduction to $2.15 per kg at a 99% reduction. The difference in price is due to electrolyzer and injection system economies of scale. At these cost levels, emissions can be reduced by up to 99% while producing a levelized cost of electricity less than $0.19 per kWh. This is shown in Figure B-13, which shows the Sc4 LCOE.

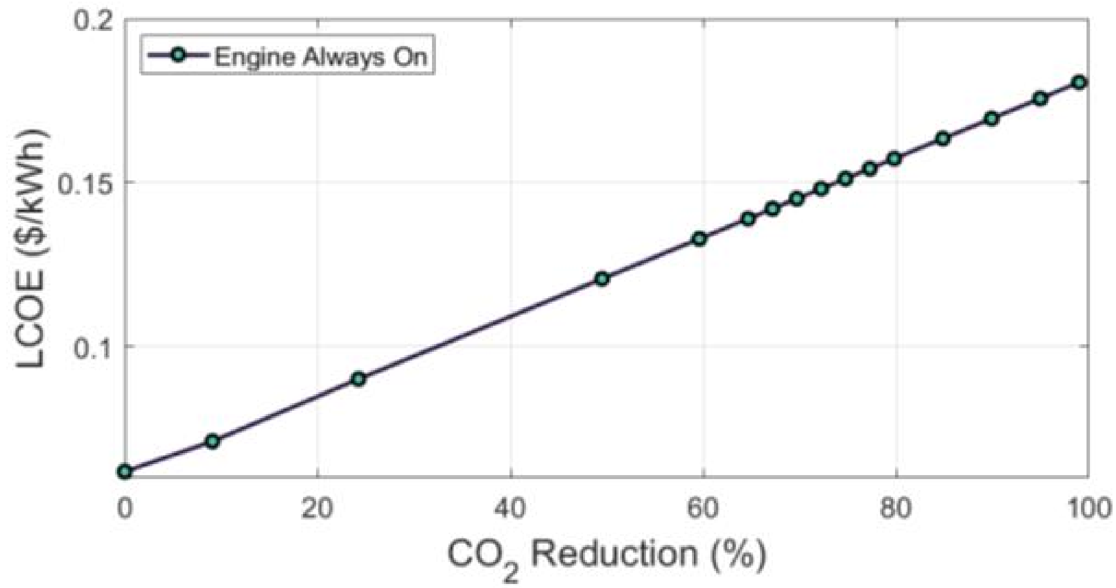

Figure B-13: Levelized cost of electricity for all simulations captured in the Sc4 scenario.

Aside from the engine operational results, another major difference between Sc4 and all preceding scenarios is how H_2 storage is used. In all previous scenarios, optimal operation resulted in the immediate use of any H_2 production. Storage was only used in instances where renewable resource limitations resulted in differences between instantaneous H_2 production and demand. Under Sc4, storage is assumed to occur through use of existing pipeline infrastructure. Under the current set of assumptions, peak storage capacity appears to range from nearly 500 tonnes at 25% carbon reduction to approximately 1,750 tonnes at a 99% reduction.

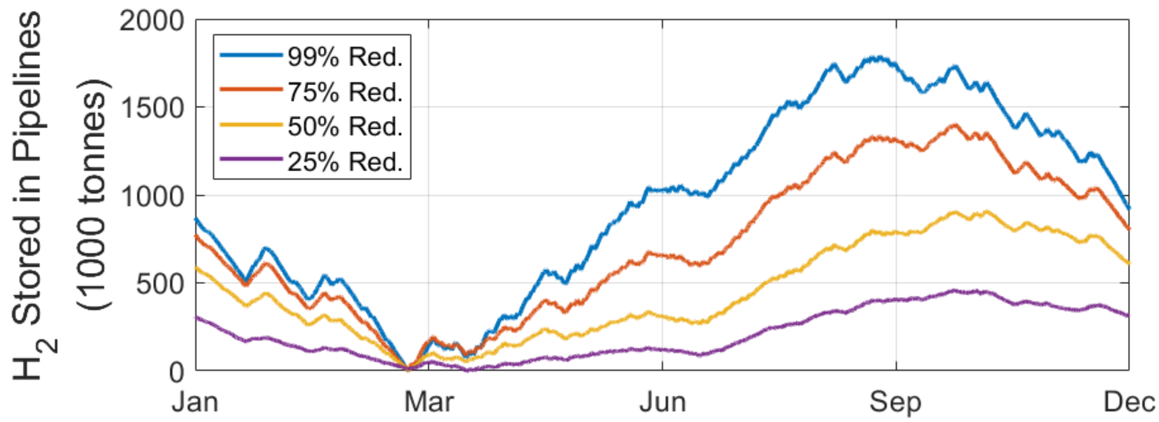

Figure B-14:Pipeline H2 storage dynamics throughout the year for carbon emission reductions ranging from 25% to 99%. Storage is taken as the cumulative sum of hydrogen injection minus use in the GT.

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Appendix C—Technology Gap Assessment

TECHNOLOGY GAP REPORT

"Hydrogen Based Energy Storage System for Integration with Dispatchable Power Generation—Phase I Feasibility Study"

28 February 2022

US Department of Energy Contract FE-0032021

DE-FOA-0002332

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U.S. Department of Energy
National Energy Technology Laboratory

C-1 Gas Turbine Technology

Existing dry low emissions (DLE) technology utilizing lean premixed systems for NOx reduction can have a small increase in emissions as a result of the diffusion style or partially premixed pilot fuel circuit used to provide stability to the main flame. For low blends of hydrogen (H2 <= 20%), the effect is only on the order of a few ppm of NOx [5] and is able to be handled for the most part with existing emission margins. However, as the fuel blend increases above 20% H2, the NOx emission increase can be larger and may affect existing emission requirements if left with the existing engine combustion system controls.

Recent efforts to better understand NOx emissions from high H2 combustion have identified reporting errors (biases) in dry volumetric measurements based on the larger water content in the exhaust from high H2 combustion as compared to natural gas [6]. The bias or error is a direct result of using a dry volumetric sample. With more water produced and thus removed for the dry sample, there is a concentrating effect that falsely increases the NOx emissions. The oxygen measurement is also measured dry and on a volumetric basis and also includes the bias. The oxygen measurement is important because it is routinely used to correct the NOx emissions to a reference O2 level, 15% for gas turbines. The combined effect of NOx and O2 bias can be as high as 35% for 100% H2 combustion compared to natural gas. For the case of 30% H2, the bias is much smaller and only about 4%, but can still be significant for a single digit NOx DLE combustion system. The issue will need to be addressed with the emission regulators with discussions being driven by gas turbine organizations such as the Gas Turbine Association (GTA) and European Turbine Network (ETN).

One way to mitigate the additional NOx emissions is to use closed loop engine control based on the H2 content in the fuel. This control scheme takes advantage of the lower turndown capability with hydrogen that will allow reduced pilot settings and thus lower NOx emissions. In order to use this method, a reliable, low cost and fast acting sensor capable of determining the level of H2 in the fuel is required to be able to control the pilot fuel circuit in real time. Additionally, the fuel algorithm is dependent on the energy content of the fuel to minimize the flammability risk in the exhaust. Having a fast acting sensor to input the hydrogen content of the fuel will help mitigate operational risk. An evaluation of existing technology available will be included as part of the Pre-FEED study to be performed by the EPC with input from Solar Turbines.

Hydrogen poses risks to gas turbine operation at start-up and during upset conditions where flameout can occur[1,2]. Although failed start attempts and combustion flameouts are upset conditions, they are not rare. When they occur and before the fuel supply is shut-off by controls, a charge of unburned fuel and air can enter the exhaust duct with a mixture that is above the lower flammability limit (LEL). For fuels containing hydrogen, the LEL is reduced significantly so that these type of trip events can potentially create flammable mixtures with hydrogen and natural gas blends, which would not be flammable with natural gas alone. If this charge ignites and combusts within the exhaust system a substantial pressure rise can develop that could cause moderate to severe damage in the exhaust system. The extent of the pressure rise depends on how the charge of fuel burns. The flame would start as a slow flame. Depending on the equivalence ratio, the influences of mixture temperature and the duct geometry would either cause the flame to stay in the slow flame regime, transition into a fast flame, or in the worst case a detonation wave. The magnitude of the pressure rise also depends on the fuel composition, equivalence ratio and initial temperature of the fuel-air mixtures; the length, size and shape of the duct; and obstacles in the flow path[3,4].

For the Titan 130 (T130) installed at UC Irvine operating on 30% Hydrogen by volume blended with natural gas, the fuel to air ratio in the exhaust will exceed the LEL but remain in the slow flame regime in the event of a flameout at full load. For existing gas turbine

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plants operating in the field, Solar Turbines has proposed the implementation of an exhaust air dilution system when required to lower the fuel to air ratio below the LEL to insure an un-ignitable mixture. The impact of the air dilution system has not been evaluated for operation with the waste heat recovery system. It is expected that it will have a detrimental impact on the performance. For this reason, Solar Turbines is proposing the investigation of a passive mitigation for exhaust over pressure in the event of re-ignition after a flameout. NFPA 68 Standard on Explosion Protection by Deflagration Venting outlines approaches for pressure release devices that provide safe venting and reduce the overall mechanical design requirements of the exhaust to contain such an event. The use of a deflagration venting system will allow the turbine to safely operate with exhaust levels that could exceed 100% of the LEL for the gas composition.

C-2 Integrated Controls

Additional work on developing the final design requirements for the operational signal to enable the gas turbine and the hydrogen fuel content composition signal will be developed in conjunction with the overall project design. Turbine controls will be optimized using the hydrogen fuel content signal to minimize exhaust LEL risk. Additional system design for inclusion of a battery energy storage system will be added in order to cover short duration events before the gas turbine generator and CHP plant can be brought on-line to produce steam and electricity.

C-3 Renewable Hydrogen Generation

Anaerobic Digestion (AD), thermochemical and electrolysis are some of the commercial or near commercial technologies to produce a large scale renewable hydrogen [1]. When considering power-to-gas and gas-to-power for storage of grid energy, electrolysis is the only technology that serves this function. Electrolysis uses applied voltage to drive a catalyzed electrochemical reaction completed via an electrolyte to evolve water molecules into hydrogen and oxygen in an equipment known as electrolyzer.

C-3.1 Electrolyzers

The three main types of electrolyzers are Alkaline (AEC), Proton Exchange Membrane (PEMEC) and Solid-Oxide electrolyzers (SOEC) [2]. Table shows the comparison for different electrolyzers. The electrolyzer's output hydrogen is often delivered at a maximum pressure of about 30 barg [3][4], with some of the more advanced models at a maximum pressure of 200 barg [5]. The hydrogen is often stored under high pressure instead of sending directly to the GT. Therefore, a higher electrolyzer H_2 delivery pressure can be beneficial for storage by reducing the compression work, as well as the footprint of hydrogen compressors.

Table C-1: Comparison for electrolyzers [6][7]

Type	AEC	PEMEC	SOEC
Advantages	- Most mature. - Good for large scale. - Long service life. - Low cost.	- Fast startup. - Good dynamic response. - No corrosion. - Simple maintenance. - Fewer components. - Allow for differential pressures across the membrane (different O_2 and H_2 outlet pressures).	- Highest theoretical efficiency. - Low cost. - High pressure durable.
Disadvantages	- Slow startup. - Degradation for frequent cycle. - Corrosion. - Complicated maintenance. - Involves many components.	- High costs. - Requires noble and limited metals (Platinum).	- Least mature. - Bulky system design. - Brittle ceramics. - Least cost dependency.
Commercial Model Examples [5][8][9][10][11]	Nel®: A485, A1000 Sunfire®: HyLink Alkaline	Nel®: MC500 Siemens®: Silyzer300 Cummins®: HyLIZER series	Sunfire®: HyLink SOEC

C-4 Renewable Hydrogen Storage

Hydrogen storage is a key enabling technology for hydrogen economies and mobilities in both stationary and mobile applications. Hydrogen has low energy density in ambient temperature and pressure. Therefore, physical-based storage methods including compression and cryogenic liquefication, as well as material-based storage method including Liquid Organic Hydrogen Carriers (LOHC) are some of the current or developing methods for hydrogen storage [12].

C-4.1 Physical Storage: Compression

Compressed hydrogen (CH_2) storage is by compressing the gaseous hydrogen to an extremely high pressure, which is often 250 bar for large quantity storage and 350 or 700 bar for on-board storage using cylindrical or spherical storage containers [13]. CH_2 is currently the most mature and commercialized technology for hydrogen storage, and it can be divided into above ground or underground storage.

C-4.2 Above Ground CH2 Storage

CH_2 storage tanks are typically used for mobile applications (e.g., fuel cell vehicles) at a pressure of 350 bar or 700 bar for storing between 5 to 10 kg of hydrogen [14]. Some commercialized products stacked a number of these storage containers to store enough hydrogen for stationary power generation. For example, Quantum Fuel Systems® and Hexagon Lincoln® have recently proposed the concept of storage trailers, which can store several hundred to over a thousand kg of hydrogen by stacking cylindrical containers in a trailer [15][16]. Above ground CH_2 storage is one of the few commercialized technologies, and it is suitable for mobile applications as well as current and near-term storage when transitioning to hydrogen blending for stationary applications. The estimated storage container cost per unit of CH_2 is around $1,100.

C-4.3 Underground CH2 Storage

For stationary power generations, larger quantity and longer duration of hydrogen storage is often required, which makes underground storage be a better option. Similar as the conventional natural gas underground storage, underground hydrogen storage often utilizes aquifers, depleted deposits of fossils, salt caverns [17], or drilled shaft technology (thus no need to be location constrained) to store hundreds of thousands of CH_2 [18][19]. Underground storage typically has a larger capital cost but a lower unit cost of storing hydrogen due to economies of scale. Most of the underground storage methods are still under commercial demonstration. An Australian blind bore drilling company Ardent Underground® is conducting a pilot demonstration of underground storage in Australia with a nominal 50,000 kg H_2 at a pressure of 220 bar with an estimated unit cost of \$320/kg H_2. Commercialization is expected to begin in 2022-2023, when the company offers storage in the range between 20,000 to 500,000 kg of H_2 with a maximum pressure of 300 bar. As time proceeds, the company plans to increase the storage volume by the shaft storage solution, thus further reducing the specific unit cost of hydrogen storage. Another demonstration of underground storage starts in Utah since 2019, where Mitsubishi® cooperated with Magnum Development® to build the world's largest storage facility for 1,000 megawatts of clean power, partly by putting hydrogen into underground salt caverns, to support California's Advanced Clean Energy Storage (ACES) project [20]. According to Mitsubishi, there will be 150,000 MWh of renewable power storage capacity completed in the first phase of the project by 2025, which is equivalent to nearly 150 times of the current U.S. installed battery storage base.

C-4.4 Physical Storage: Liquefaction

Liquefaction is commonly used in the space programs and to transport and deliver a large quantity of hydrogen over a long distance in the absence of pipelines. Liquefied hydrogen (LH_2) is formed by condensing the gaseous hydrogen to -253°C until it reaches the liquid phase under ambient pressure. LH_2 has about 4.5 times higher energy density than CH_2 at 200 bar [21], and thus LH_2 can store more hydrogen than CH_2 and be beneficial for a long distance transportation. Also, LH_2 does not require hydrogen compressors that are required for CH_2, thus reducing the system footprint and costs, as well as capable of storing the hydrogen under ambient pressure. However, liquefication is expensive and requires more than 30% of the usable hydrogen energy content [22]. Transportation, storing and venting off LH_2 under ambient environment often causes evaporation or "boil off" losses, which are estimated to be range from 2% for a smaller delivery amount of around 100 kg/day, to 15% for a larger delivery amount of around 1,800 kg/day [23]. Therefore, research-to-date has focused on minimizing evaporation losses by improving the insulation material and better thermal management on the storage system. In October 2021, Air Products® announced the operation of the world's largest liquid hydrogen plant in Taxes to supply around 30,000 kg H_2 per day from the existing pipeline network near the Gulf of Mexico, which is the world's largest hydrogen pipeline system [24]. Other companies such as Air Liquide®, Linde® and Chart Industries® offer commercialized hydrogen liquefiers, which can produce from around 240 kg LH_2 to 30,000 kg LH_2 per day [25][26][27]. The estimated cost of liquefaction (excluding the cost of LH_2 storage) is around \$0.66/kg LH_2 to \$1.13/kg LH_2 assuming a useful life of 150,000 hours [28].

C-4.5 Chemical Storage: Liquid Organic Hydrogen Carriers (LOHC)

Liquid Organic Hydrogen Carriers (LOHC) are chemical organic compounds which can absorb or release hydrogen by chemical reactions, making them capable for storing hydrogen utilizing existing infrastructure under atmospheric conditions [29]. The reaction is exothermic (releases heat) during hydrogen absorption, and endothermic (requires heat) during hydrogen desorption. When utilizing LOHCs in combined heat and power (CHP) systems, the waste heat from CHP can be utilized to release the hydrogen from the LOHCs due to the endothermic reactions, thus increasing the CHP overall system efficiency by decreasing the amount of heat rejection [30]. In the absence of pipelines to deliver hydrogen for stationary applications, LOHCs can be potential candidates for long distance transportation. Some of the common LOHCs include naphthalene, N-ethyl carbazole (NEC), and toluene/methylcyclohexane (MCH) system [31]. One of the largest commercial demonstrations for LOHC system started on 2018 was completed based on a large-scale pilot-plant facility to transport hydrogen between Brunei and Japan to support a global hydrogen supply chain project [32]. The pilot plant can produce 300 N-m^3 per hour of hydrogen, which is about 27 kg of hydrogen per hour. According to European Commission, the variable operation cost for LOHCs is 1.51 €/kg, which converts to \$1.71/kg at the time of writing, and the capital cost is around 1.56 €/kg, which is \$1.77/kg [33].

Table C-2: Comparison of different Storage Methods

Storage Methods	CH_2		LH_2	LOHC
	Aboveground	Underground		
Advantages	- Mature and commercialized. - Affordable. - Good for small scale. - Highly mobilized.	- Large scale storage for cheaper unit cost. - Durable and existing infrastructure can be used. - Ideal for long-term stationary power generation.	- Extremely low liquefaction unit cost. - 4.5 times higher energy density than CH_2 at 200 bar. - No compression. - Ambient pressure. - All scales.	- No compression and liquefaction required. - Ambient storage temperature and pressure. - Insignificant footprint.
Disadvantages	- Not ideal for large scale. - Takes significant footprint. - Requires highest pressure compression, safety concern and extra equipment.	- Under commercial demonstration only. - Lack of mobilization. - Non-ideal for short-term storage. - Requires significant investment.	- High capital cost. - Heavy Energy consumption for liquefaction. - Easily evaporated (Losses). - Requires large footprint for liquefaction.	- Lab or Commercial development stage only. - No dependable safety, cost, and efficiency information. - Requires heat to obtain hydrogen.
Technologies/ Methods	- Fuel cell vehicles or other mobile applications. - Near-term H_2 blending for stationary applications.	- Aquifers - Depleted deposits of fossils - Salt caverns - Drilled shaft	Hydrogen Liquefiers.	Organic compounds to absorb and desorb H_2.
Status and some involved companies	- Commercially available. - Quantum Fuel Systems®, Hexagon Lincoln®, Steelhead Composites®	- Commercial demonstration. - Mitsubishi® - Ardent Underground®	- Commercial demonstration for large scale and commercialized for small-medium scale. - Air Products®, Linde®, Air Linde®, Chart®	- Commercial prototype. - Chiyoda®.
Estimated Scale	Several kg to thousands kg CH_2 (stack trailers).	Tens to hundreds of thousands CH_2.	Hundreds to hundreds of thousands kg LH_2.	Hundreds to thousands kg H_2.
Working Pressure	250 to 350 bar (Stationary). 350 or 700 bar (Mobile).	Maximum of 300 bar.	Ambient pressure.	Ambient pressure.
Estimated Costs	Container: $750 - $1,100/kg CH_2.	$320/kg CH_2.	Liquefaction: $0.66 - $1.13/kg LH_2 (150,000 hours)	$1.71/kg LOHC operating cost. $1.77/kg LOHC capital cost.

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Appendix D—Commercialization Plan

COMMERCIALIZATION PLAN

For

"Hydrogen Based Energy Storage System for Integration with Dispatchable Power Generation—Phase I Feasibility Study"

28 February 2022

US Department of Energy Contract FE-0032021

DE-FOA-0002332

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D-1 Introduction

Solar Turbines Incorporated (Solar) has been part of a DOE Project team lead by the University of California-Irvine (UCI) and also involving Southern California Gas Company (SoCalGas) to perform a Phase I feasibility study to develop a hydrogen based energy storage system for integration with a dispatchable power generator. In this case, the dispatchable power generator is an existing Solar Turbines Titan 130 gas turbine (13 MW) with a dry low emissions (SoLoNOx™) combustion system that is part of the UCI central plant.

D-2 Background

Solar Turbines currently offers diffusion flame conventional combustion industrial gas turbine models that have excellent hydrogen capability up to 100% hydrogen (H2). Due to pollutant emission regulations, the conventional combustion platform has limited applications without the use of water injection and exhaust aftertreatment for emissions abatement. These pollutant reduction strategies are not desirable due to high cost, added complexity, and the limited availability of high-quality water. Making the emissions challenge worse, hydrogen rich fuels have a significantly higher adiabatic flame temperature that elevates NOx emissions considerably with diffusion style combustion systems. Despite these disadvantages, Solar has industry leading experience in the less than 30MW industrial size class with hydrogen rich fuels. Solar's installed fleet of over 50 gas turbine generator set packages with conventional combustion systems have accumulated over 2 million hours operating on process gases such as coke oven gas and refinery gas that contain H2 in the range of 30% to 80% (by volume) starting back in 1985.

Today, gas turbines that use dry low emission (DLE) technologies are clearly preferred for most applications due to their cost effective, low emissions performance. Solar Turbines' engine configurations with dry low emissions (SoLoNOx™) combustion systems are currently approved for up to 20% hydrogen mixed with pipeline natural gas. The installed fleet of SoLoNOx turbines includes refinery and process gases applications with hydrogen content ranging from 4% to 15% starting back in 2003.

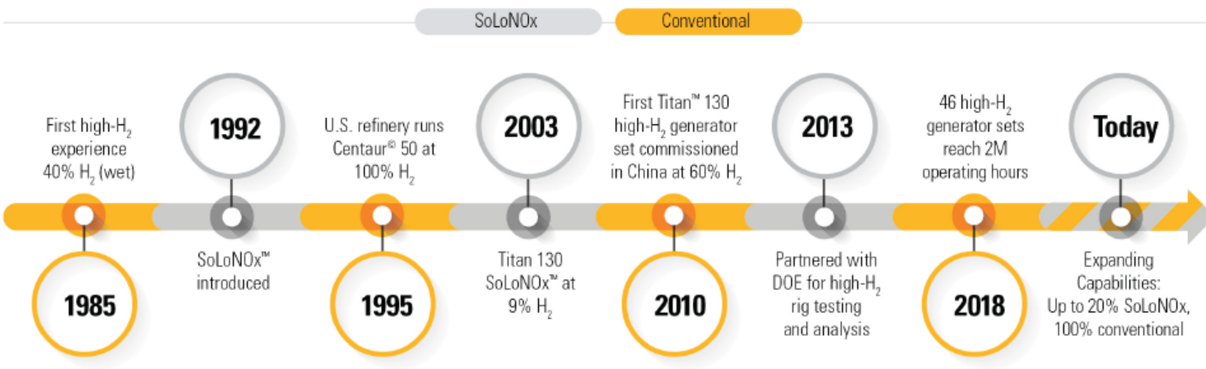

Figure D-1. Solar's H2 Technology Experience (55 Units with 2M Operating Hours)

In order to qualify DLE gas turbines for higher H2 operation with traditional lean premixed combustion systems, engine qualification tests are needed. The DLE combustion system concerns such as flashback and higher adiabatic flame temperatures leading to higher NOx emissions are well documented [1,2]. For example, single injector rig testing on H2 fuels has shown that a Titan 130 SoLoNOx injector was capable of operation at up to 65% H2 blended with natural gas without experiencing flashback [3]. Additional engine tests to qualify higher levels of H2 are required as is being proposed as part of this UCI DOE H2 Integration project. Solar has committed to support the SoLoNOx combustion system product line for H2 fuels during the transitional period where low level blends of H2 and NG are expected to dominate the use case in the H2 market for gas turbines in the next 10 to 20 years. Solar has also committed to develop a new DLE combustion system capable of up to 100% H2 with low emissions by 2030 for both the new equipment and retrofit applications for when the H2 production market matures and H2 availability is plentiful.

D-3 Market Scenarios

In the companion Technoeconomic Analysis appendix (Appendix B), several market scenarios were included. These involved:

"business as usual" which uses current rates (standby, demand, and TOU) and various constraints for the UCI specific case. The basic price of electricity is 0.09/kWh. This scenario include existing low cost biogas contracting which is not likely to be generally available. Natural gas rates are less than 60 cents per therm. The campus pays a departing load charge of $0.02 / kWh to maintain connection to the utility grid.

Decarbonized Electric Procurement in which the campus procures carbon free power from in state utility scale plants. This allows much less cost to the campus for price of electricity (0.03/kWh vs 0.09/kWh).

Another scenario is the “LMP Access” situation which is a possible future scenario in which the campus can purchase electricity at the day-ahead locational marginal price (LMP). Further—biogas is eliminated as that is not a generally available option.

Finally, cases are considered in which LMP is not available, and that basic electricity charges rise to 0.18/kWh.

In all of these scenarios, it is challenging to realize a financially attractive paypack on use of the existing fossil asset. Using the electricity directly rather than creating hydrogen appears to be the preferred scenario at least for the UCI situation. Part of the challenge is that the energy reduction measures at the campus have resulted in reduced demand. Combined with recent installed solar on campus, the gas turbine is effectively oversized for electricity. The heat is still needed. So other cases including downscaling the fossil asset or transitioning to a more efficient electrical generator does appear to make sense from a primarily financial basis with consideration for decarbonization.

D-4 Domestic and international market applicability

In the many different market segments that industrial gas turbines serve, there are two main opportunities to increase sustainability and reduce carbon emissions in mitigating the effects of climate change. The first opportunity is the new equipment market that is looking out 20 to 40 years when carbon reduction goals are phased in and become significant. The second opportunity is the sizable existing fleet of industrial gas turbines that will play an important role during the transitional years from now to 2040 as the industry changes from a fossil fuels based model to a renewable/sustainable model for dispatchable energy production. For the existing fleet, it is anticipated that carbon reduction will first be realized by using the existing DLE gas turbine combustion systems with low level blends of H2 in NG in the 10% to 30% range with an upper limit anticipated to be approximately 50% H2 for the existing lean premixed technology.

Each of these two market opportunities can be broken down into the Oil & Gas (O&G) and Power Generation (PG) sectors. For the over 16,000 Solar industrial gas turbines sold worldwide, about half are compressor sets and mechanical drive applications with the other half being generator sets. Solar gas turbines can be found around the world at O&G operations including upstream, midstream and for power generation; Industrial & process facilities including pulp & paper, ceramics, food & beverages, chemicals, cement/gypsum, dairies, pharmaceuticals, plastics, refineries and tire & rubber production; and commercial & institutional facilities including universities, hospitals, commercial buildings, data centers, district heating & cooling plants and resorts & hotels with most PG configurations in high efficiency combined heat and power (CHP).

This project focuses on the PG market at a university with a H2 based energy storage system for integration of renewables and providing dispatchable renewable power and carbon reduction. The key element for Solar is to provide the ability to test and qualify the engine on higher levels of H2 and to do that in an integrated system with renewables and H2 storage. The Phase I Feasibility Study has shown the need for integrated solutions that take into account the type of renewable resources available along with site specific requirements.

Industrial gas turbines are an important source of rapidly dispatchable power that are becoming more vital for grid stability as renewable electricity generation grows. The global market for renewable dispatchable power with carbon reduction is growing and is creating significant opportunities to use existing fossil fueled gas turbines converted to burn blends of H2 with NG across a number of market sectors. Solar aims to use this university project to develop a more general framework of carbon reduction solutions for its industrial gas turbine markets.

D-5 Market advantage of the concept

The gas turbine portion of the project is focused on qualifying the existing DLE combustion system technology in an engine with higher levels of H2 blended with natural gas up to about 30%. Based on prior DOE funded work [3], higher blends up to about 50% H2 are anticipated to be possible in the future with this existing DLE combustion system technology. Ultimately, using this higher level of H2 will largely be dependent on flashback margin and could be different for each gas turbine product. Modifications to package systems will be required to accept higher levels of H2, but the existing engine and combustion system will remain the same thus offering an advantage in cost and reduced scope for modification.

For Solar's current DLE system (SoLoNOx), the NOx increase for low levels of H2 up to 30% are on the order of only a few ppm (2 to 4 ppm) [2]. With engine testing, it may be possible to reduce the NOx emissions with reductions in pilot settings as the H2 in the fuel generally improves combustion stability. These introductory levels of H2 with NG could be utilized sooner rather than waiting for a new fully optimized and proven DLE combustion system for up to 100% H2 in the 2030 timeframe. The intermediate levels of H2 also support the development of a H2 economy where blend levels can be adjusted higher as more H2 is produced and becomes available to the market. Gas turbine applications using higher blends of H2 will be paced by the supply of hydrogen and so the program is tailored to investigate the lower risk blends as outlined.

For a conventional combustion system, the increase in NOx is large compared to a lean premixed system due to having a much higher adiabatic flame temperature. The Solar DLE (SoLoNOx) combustion system could be retrofitted on older engines replacing the conventional combustion systems. This approach offers the capability to burn low to intermediate levels of H2 blends with NG and achieve much lower emissions than conventional combustion.

D-6 Estimated additional revenue

As more organizations and governments develop and implement carbon reduction programs and place higher penalties on carbon emissions, the opportunity to provide a dispatchable renewable power generator becomes very attractive. As discussed earlier, both the new equipment market and existing fleet could benefit from an energy storage system for integration with renewables and a dispatchable power generator. Additional revenue could be generated by selling into the traditional industrial power generation market and the developing distributed generation market. An even larger opportunity to impact both carbon reduction and revenue generation is to retrofit the large existing fleet of gas turbines. Additional revenue from the sale of retrofits could be on the order of 10% to 20% of the original package price depending on the age of the unit and the type of combustion system (conventional or DLE).

D-7 Estimated non-financial benefits to the asset owner

Please see Appendix B.

D-8 References

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