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Economically Viable Intermediate to Long Duration Hydrogen Energy Storage Solutions for Fossil Fueled Assets

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

EXECUTIVE SUMMARY

This report was prepared as an account of work sponsored by the Office of Fossil Energy and Carbon Management of U.S. Department of Energy under Funding Opportunity Announcement Number DE-FOA-0002332 “Energy Storage for Fossil Power Generation”. The work aimed to explore and advance an innovative hydrogen energy storage system – the synergistically integrated hydrogen energy storage system (SIHES) – that has the following characteristics:

- Compatible with existing or new coal and gas fuel electricity generation units,
- best suited for intermediate to long duration energy storage, from 12 hours to weeks even months, and
- capable of storing energy at the utility scale – hundreds of MWh to GWh energy storage with power output level in tens to hundreds of MW.

In accordance with the FOA, the work was a “Conceptual Design Study for Engineering Scale Prototypes of Hydrogen Energy Storage Integrated with a *Site-Specific* Fossil Asset”, in two phases. Phase I was a site-specific concept feasibility study in partnership with Exelon Corporation and Tennessee Valley Authority (TVA). Upon reviewing and analyzing the suggested fossil power plant sites, their operation histories, and electricity market price (LMP) fluctuations over days (short term) and weeks to months (long-duration), we identified the most preferred scenario and strategy for early adoption of SIHES for fossil plants, that is, to use SIHES as peaking power generation units (so named as **HyPeaker**) as the first market entry point. The learnings from such early adoption would help further advance the technology and gain market confidence and acceptance to add larger SIHES to baseload power plants at hundreds MW to GW level.

In Phase II, preliminary front-end engineering design (Pre-FEED) studies was carried out to further develop and refine a site-specific HyPeaker, to demonstrate both the technical feasibility and the economic viability to integrate the HyPeaker “within the fence” of a fossil power plant. This specific site was TVA’s Johnsonville Combustion Turbine Plant. The HyPeaker was designed and engineered to integrate with a 60MW aeroderivative gas turbine unit already available at TVA’s Johnsonville site with the following primary requirements. The HyPeaker consists of three major sub-systems:

- A hydrogen production sub-system (E-H_2). It uses the excessive electricity from clean sources to produce hydrogen. Alkaline electrolyzer was selected, based on the consideration of its technology maturity, capacity and cost over other electrolyzers available on the markets at multi-MW level, as well as its compatibility with the projected hydrogen production operation profile of HyPeaker.
- A hydrogen storage sub-system. Hydrogen produced from the E-H_2 sub-system is stored over the period of hours to weeks even months at 3000 psi before it is used for electricity generation later. Big-Ton high-pressure gaseous hydrogen storage vessel, based on the innovative steel-concrete composite vessel (SCCV) was chosen as (i) it is the most cost-effective and mature hydrogen storage technologies on the market, for the amount (in tens to hundreds of tons) and duration (weeks to months without lost) of hydrogen stored, and (ii) its domestic manufacturing availability.
- An electricity generation sub-system (H_2-E). The HyPeaker utilizes the 60MW aeroderivative gas turbine unit that existed already at the Johnsonville site for this purpose. This has two major advantages unique to fossil power plants – it not only avoids the additional capital cost for a different H_2-E sub-system but also offers the flexibility of mixing H_2 and natural gas which has many benefits in the early transition phase of hydrogen energy storage systems in long-duration applications.

A holistic system level TEA modeling tool specific to HyPeaker was developed in this project to optimize the engineering design of the Johnsonville site-specific HyPeaker for cost and performance.

The optimal design and specification of the Johnsonville site-specific HyPeaker are the following:

- Alkaline electrolyzer: 3MW
- Big-Ton storage vessel: 11,000kg H_2 at 3000psi.
- 4-stage diaphragm hydrogen compressor: 55kg-H2/hr from 150psi to 3000psi.

The HyPeaker is designed to have the capability of providing sufficient hydrogen for 90% continuous operation of the HyPeaker. All major components have design life of 30 years.

The capex of HyPeaker is estimated at **$7.1M**. This included $1.5M for the electrolyzer, $5.6M for the storage vessel and compressor. Since the aeroderivative gas turbine unit was already available at the Johnsonville site, its cost was not included. Cost of other minor components/parts and installation cost were not considered in the Pre-FEED study.

Other key findings from this work include the following:

- HyPeaker can be designed, manufactured, installed and integrated with the fossil power plants, with sub-systems and components commercially available on the market today, even when it is scaled up to an order of magnitude larger than the one at the Johnsonville site. HyPeaker is a technologically viable solution to cover a wide range of energy storage duration needs, from daily peaking operation to seasonal shifting for fossil fueled assets.
- The cost advantage of SCCV based Big-Ton H_2 storage vessel made it possible to "oversize" the H_2 storage subsystem to achieve overall system level cost optimization. The benefits are two-fold. First, it allows to significantly reduce the capacity and cost of electrolyzer by spreading H_2 production over a much longer period of time when the fuel cost for electricity production is low. Second, it allows to balance the hydrogen production and usage shift over weeks to months (such as using the H_2 produced in May/June to meet the peak demand in July and August), to achieve the overall system cost minimum. As such, the capital cost of HyPeaker system using the Big-Ton was less than half of the cost of a system with today's steel tube based H_2 storage system. The HyPeaker has even better cost advantage Li-ion battery based energy storage system. The estimated capital cost of Li-Ion battery system would be at $38M, under the same projected 20-year electricity generation profile of the Johnsonville site. This is over 5 times more expensive than the HyPeaker system.
- Since industry scale energy storage systems do not have 100% energy conversion and storage efficiency, energy storage systems using fossil fuel generated electricity would *increase* the CO_2 emission. This is particularly the case for HyPeaker due to its low round trip efficiency. Therefore, a more sensible solution would be to the excessive or curtailed electricity from CO_2 emission free sources such as solar farms, wind farms or nuclear power plants, to produce hydrogen, and integrate them with the HyPeaker. Electricity from TVA's nuclear power plants was used for the Johnsonville HyPeaker.
- The economic viability of HyPeaker is expected to be further improved when global supply chains are taken into consideration. For the same Johnsonville site specific HyPeaker, the capex would be reduced to ~$3.6M from ~$7.1M, and the added LCOE is reduced to ~$85/MWh. With the financial and economic incentives in the bipartisan Infrastructure Investment and Jobs Act, the cost of domestically produced HyPeaker sub-systems would be at the level of today's global suppliers within 3-5 years. Since the peaking units generally operate at peak usage period, thereby demanding higher price, the projected $85/MWh LCOE would be within the realm of financial viability for TVA and other utility operators.

1 INTRODUCTION AND BACKGROUND

Energy storage co-located with fossil energy assets offers a suite of benefits to asset owners, the electricity grid, and society. These include more reliable and affordable energy supply, cleaner environmental performance, and stronger energy infrastructure. To realize these benefits, the Department of Energy's (DOE) Office of Fossil Energy and Carbon Management (FECM) has initiated a new program – the Advanced Energy Storage Program. This program conducts research and development to advance energy storage technologies and integrate them with fossil assets to reduce barriers to wide-spread deployment.

Energy storage concepts are applicable to a wide range of fossil-fueled assets. These include existing and new, large-scale coal- and gas-fueled Electricity Generating Units (EGUs) with and without carbon capture, fossil-fueled industrial facilities (e.g., steel making, refineries, chemical production), fossil-fueled distributed generation assets (e.g., fuel cells, microgrids), and small-scale fossil-fueled peaking assets (e.g., aero-derivative gas/H_2-fueled turbines or reciprocating engines).

Fossil EGUs are increasingly required to achieve high ramp rates and high turndown to offset VRE production, though many plants are limited in their capability to achieve these targets to avoid damage due to thermal cycling of components. There are also opportunities to increase revenue by providing energy when the price is most valuable. Integration of energy storage may address these technology gaps while providing additional benefits to the plant, grid, and the environment.

The most mature energy storage technologies have not been demonstrated as a system integrated with a full-scale fossil EGU. Some have been demonstrated at large-scale (>50MWh) in different applications, whether as stand-alone storage or as an integrated hybrid system with a generating asset (not necessarily fossil). Others have been demonstrated at small-scale with or without integration.

In June 2020, FECM issued a Funding Opportunity Announcement DE-FOA-0002332 "Energy Storage for Fossil Power Generation". It focused on maturing energy storage technologies that have the potential to be integrated with large-scale fossil assets, both existing and new build, with and without carbon capture. This research was in response to the Area of Interest 1 (AOI 1): "Design Studies for Engineering Scale Prototypes", focusing on advancing near-term, fossil-fueled asset-integrated, *hydrogen energy storage solutions* toward commercial deployment.

Per FOA, the scope of work under AOI 1 would include feasibility studies (Phase I) and Pre-Front End Engineering Designs (Pre-FEEDs, Phase II) to set the stage for subsequent site-specific projects integrating relatively mature combinations of energy storage technologies with fossil fueled assets. The scale of the energy storage technology would be suitable to provide at least 10 MWh of storage. Complimentary techno-economic analysis and commercialization planning would also occur on the more generic implementation of the proposed concepts and their potential for broad deployment.

The goal of this project was to design and engineering a cost-effective hydrogen energy storage prototype to synergistically integrate with existing or new coal and gas fueled EGUs. Such synergistically integrated hydrogen energy storage system (SIHES) would enable the EGUs to operate at its optimal baseload operation conditions, through the use of sufficiently large H_2 energy storage system to manage the dynamic changes in electric grid demand and electricity price over intermediate to long-durations (from 12 hours to weeks). Equally important is the economic viability of the solution –sufficient business incentive for utility operators to adopt such H_2 storage solution. We expected to achieve the stated technical and economic objectives through (1) innovative use of our patented ultralow cost hydrogen storage system, (2) synergistic integration with fossil assets, and (3) optimization of the design and operating variables of the SIHES considering the highly dynamic of the electricity demand.

1.1 Landscape of Large-Scale Energy Storage for Clean Energy Transition

The US and the world have experienced a major expansion into clean and renewable power generation in the past decade. Demands for large scale bulk energy storage systems also have grown significantly, to address the imbalance between the supply and demand across multiple time scales caused by the inherent intermittent nature of the renewable energy such as wind and solar. As the renewable energy continues to widen its share in the power generation market, the demands for energy storage, especially *long-duration utility level* energy storage, are projected to intensify accordingly in the next few decades [1, 2].

There are a wide variety of existing and potential energy storage solutions to support the fast-growing needs in clean energy transition, as shown in Figure 1. Hydrogen based energy storage, from technical viewpoint, is generally considered to be one of the most suitable solutions for utility scale (MW to GW power) and long-duration (days to months) storage needs [3]. Recent techno-economic studies [4-6] all pointed out that, compared to battery-based solutions, hydrogen offers more economical solutions for long duration energy storage and supply. Figure 2 illustrate the findings from one of the studies [6]. According to these studies, the generally accepted breakpoint to shift to hydrogen's favor is in the range of 10-16 hours (approximately ½ day), beyond which hydrogen-based energy storage solutions would become economically more favorable for both today applications and projected future applications. Indeed, the analyses is consistent with today's industry practice. Li-ion and other batteries are the most widely used means for energy storage in electricity generation from renewable sources such as wind or solar, but are rated for 5 hours and less for the intra-day ("daily") energy time shift [1].

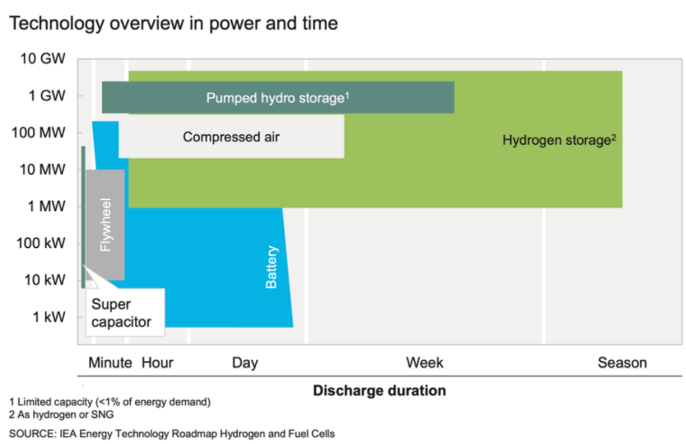

Figure 1 Energy storage technologies based on power and time. (After Hydrogen Scaleup [3]).

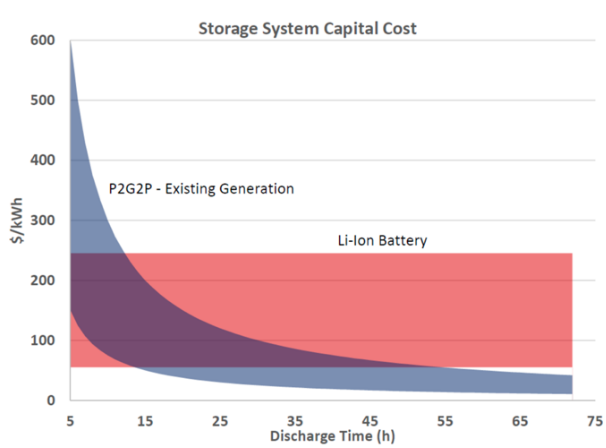

Figure 2 Storage system capital cost comparison between electricity to hydrogen to electricity (P2G2P) versus Li-Ion battery. (After California Hydrogen Business Council, 2018, [6])

Today, hydrogen-based system for long duration energy storage is emerging. Demonstration projects at multi-megawatt power level and hundreds megawatt-hour energy level are under intensive development worldwide, mostly in Europe and Asia. In July 2020, Microsoft announced the first of its kind successful demonstration of hydrogen-based energy storage system for 48 hours [7]. Storing and maintaining a sufficient supply of hydrogen to power the backup generators for 12 to 48 hours would enable the "five nines" of service availability which is standard in the industry. Microsoft is extending the development to a 3-megawatt system, which is on par with the size of a *single* diesel-powered backup generators at Azure datacenters. According to Microsoft, a datacenter would require up to 100,000 kilograms, or *<u>3.5GWh</u>*, of hydrogen for 48 hours of power generation.

1.2 Technical and Economic Gap Assessment for H_2 Energy Storage Relevant to Fossil Applications

While hydrogen based long-duration energy storage solutions are emerging, they so far have been largely focused on addressing the intermittent renewable energy (wind and solar) needs. There are two primary drawbacks in today's hydrogen energy storage solution for electricity generation*: round-trip efficiency and cost.* First, hydrogen storage has relatively low round-trip efficiency in the range of 30-40%, largely due to the relatively low efficiency of fuel cells (40-60%) compounded by the electrolyzers (60-80%). For comparison, Li-ion battery has a round-trip efficiency in the range of 80-90%, and pumped storage hydropower is about 90%. The low round-trip efficient of hydrogen energy storage would considerably increase the of cost of the fuel (electricity) in operation.

Second, as shown in Figure 2, the capital cost of hydrogen-based energy storage is lower than Li-ion ones for long duration storage. For example, at 72 hours (3 days), the capital cost of the hydrogen system is approximately \$15-20/kWh, which is only 10-20% of the Li-ion system cost. However, even at \$15-20/kWh of system capital cost, the *added* LCOE (LCOE-a)* over 30 years is estimated at \$50-60/MWh, which includes the capital cost and M&O cost but no fuel cost†. According to US Energy Information Administration (EIA), LCOE of today's coal fired power plants is about \$100/MWh, and it is \$40-60/MWh for advanced natural gas combined cycle plants [8]. Therefore, the *added* LCOE of \$50-60/MWh of hydrogen energy storage system would be prohibitively expensive for many use case scenarios including use as energy storage for fossil-fueled assets.

Penev *el al* [9] recently analyzed hydrogen storage scenarios for 24-hour operation cycle, based on today's cost of different subsystems including electrolyzers (\$737/kW), fuel cells (\$507/kW) and high-pressure hydrogen tanks (\$1168/kg-H_2). The key findings are shown in Figure 3. The levelized cost of hydrogen storage subsystem, at \$0.12/kWh, is the most expensive one – it is 3 times more than the electrolyzer (\$0.04/kWh), and 6 times more than the fuel cell (\$0.02/kWh). *Therefore, reducing the cost of the storage vessel presents the biggest opportunity to significantly lower the system level capital cost and LCOE.*

In the 2020 Edition of Hydrogen Economy Outlook published by BloomburgNEF (Table 1), salt caverns and high-pressure gaseous hydrogen vessels are by far the most economic means for hydrogen storage. However, today's high-pressure vessels are limited by its volume or size which is not practical for large scale storage. As detailed in the next section, our patented technology would address this volume limitation for grid scale.

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* *The <u>added</u> LCOE includes the capital and O&M costs of all major sub-systems of hydrogen energy storage system, encompassing hydrogen production from electricity, hydrogen storage, and electricity generation from hydrogen. It <u>does not</u> include the cost of electricity generated on-site, or provided by the electric grid. <u>We purposely separate the cost of electricity from the rest of cost, as it will be an optimization variable in our system design and optimal operation of the SIHES.</u>*

† *Basis for the estimated LCOE-a: 10MW, 7-day storage. 30-year operation life for hydrogen system, and 10 years for Li-ion battery. All capital cost paid in full at the start of operation.*

Finally, we note that research on hydrogen-based energy storage system and associated techno-economic analysis in open literature are largely toward variable renewable energy system [10-13]. Fossil power generation has its unique operation characteristics and economic considerations, which would influence the selection of technologies or subsystems, the approaches for system integration, and the operation of the system. Therefore, a hydrogen energy storage system for variable renewable energy might not be optimal for fossil plant applications.

In this project, we proposed to address the high cost of hydrogen storage subsystem and the operational and economic factors specific to fossil plants, by means of synergistically integrating our patented ultra-low-cost hydrogen storage system with fossil-fuel assets.

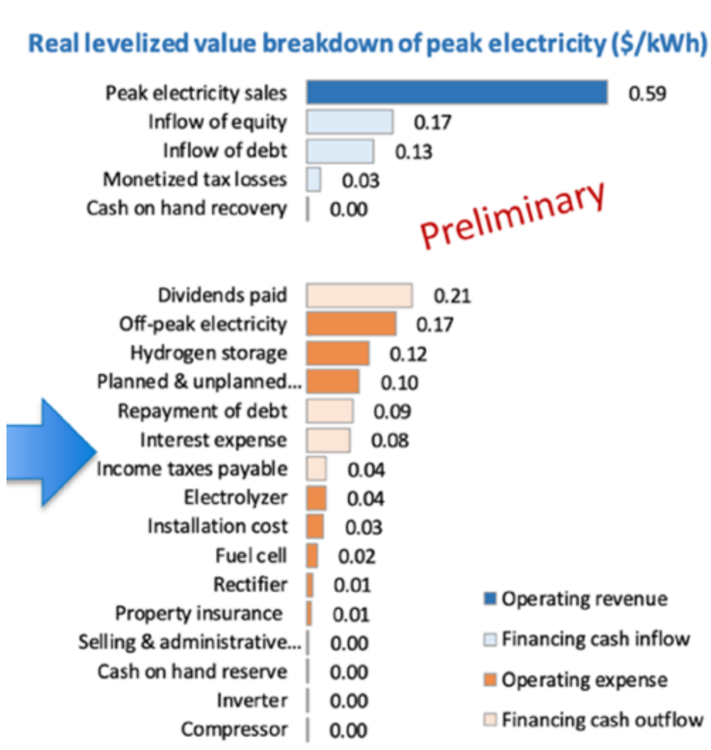

Figure 3 Levelized value and cost breakdown of hydrogen energy system. (After Penev et al, 2019 [9])

Table 1 Hydrogen storage option. Source: BloombergNEF, Hydrogen Economy Outlook 2020 Edition

	Gaseous state				Liquid state			Solid state
	Salt caverns	Depleted gas fields	Rock caverns	Pressurized containers	Liquid hydrogen	Ammonia	LOHCs	Metal hydrides
Main usage (volume and cycling)	Large volumes, months-weeks	Large volumes, seasonal	Medium volumes, months-weeks	Small volumes, daily	Small - medium volumes, days-weeks	Large volumes, months-weeks	Large volumes, months-weeks	Small volumes, days-weeks
Benchmark LCOS ($/kg)[1]	$0.23	$1.90	$0.71	$0.19	$4.57	$2.83	$4.50	Not evaluated
Possible future LCOS[1]	$0.11	$1.07	$0.23	$0.17	$0.95	$0.87	$1.86	Not evaluated
Geographical availability	Limited	Limited	Limited	Not limited	Not limited	Not limited	Not limited	Not limited

Source: BloombergNEF. Note: [1] Benchmark levelized cost of storage (LCOS) at the highest reasonable cycling rate (see detailed research for details). LOHC – liquid organic hydrogen carrier.

2 PROJECT OBJECTIVES AND SCOPE OF STUDY

The goal of this research is to explore and advance an innovative hydrogen energy storage system – the synergistically integrated *hydrogen* energy storage system (SIHES) – with existing or new coal and gas fueled EGUs that are best suited for the intermediate to long-duration energy storage needs (i.e., from 12 hours to weeks). It enables the EGUs to operate at its optimal operation conditions, through the use of sufficiently large hydrogen energy storage system to manage the dynamic changes in electric grid demand and electricity price over intermediate to long-durations.

Equally important is the economic viability of the proposed SIHES solution – it must provide sufficient business incentive for utility operators to adopt the energy storage solution. The project aims at achieving the economic viability through (1) the innovative use of our patented ultralow cost hydrogen storage subsystem, (2) synergistic integration with fossil assets to improve round-trip (E-H_2-E) efficiency, and (3) optimization of the design and operating variables of the SIHES considering the highly dynamic of the electricity demand and price.

In accordance with the FOA, the work was a "Conceptual Design Study for Engineering Scale Prototypes of Hydrogen Energy Storage Integrated with a *Site-Specific* Fossil Asset", in two phases.

Phase I was a concept feasibility design study to develop and refine the *site-specific* conceptual engineering scale prototype SIHES that would be tightly integrated with a fossil power plant suggested by fossil electricity utility partners on the project team. Identify the most likely scenario and strategy for early adoption of hydrogen energy storage system for fossil plants.

Phase II was the preliminary front-end engineering design (Pre-FEED) study to further develop and refine the site-specific SIHES design that can be integrated to a fossil power plant. It included concept design, design, basis, and process description, and performance and cost results. A techno-economic analysis was carried out to assist the optimal design and engineering of the SIHES system and identify operation scenarios for economic viability of hydrogen storage system in fossil fueled assets. Achieving the Phase II technical and economic objectives would build the foundation for subsequent site demonstration, and eventual wide-scale deployment of the proposed SIHES technology in fossil power generation.

3 TECHNICAL CONCEPT AND APPROACH

3.1 Energy Storage Concept - SIHES

Figure 4 and Figure 5 illustrate, respectively, the proposed design concept and operation principles of SIHES. Shown in Figure 4, SIHES principally consists of a hydrogen production subsystem (E-H_2), a hydrogen storage subsystem (SCCV), and an electricity generation subsystem (H_2-E). The basic functions of each subsystem are: (1) use the excessive or curtailed electricity from EGU to power E-H_2 to generate hydrogen when the grid demand (and electricity price) is low, or optionally, use electricity from clean electricity sources via the grid to generate hydrogen when the price of grid electricity is economically favorable; (2) use the ultra-low cost SCCV to store large amount of hydrogen (tens to hundreds of tons) sufficient for electricity generation over a long period of time (days to weeks), and (3) use H_2-E to generate electricity from the stored hydrogen (or hydrogen/gas mix) when the electricity demands exceeds the base load of the EGUs. The by-produce heat from fossil fueled turbines including aeroderivative gas turbines can be supplied to E-H_2 subsystem to improve its efficiency.

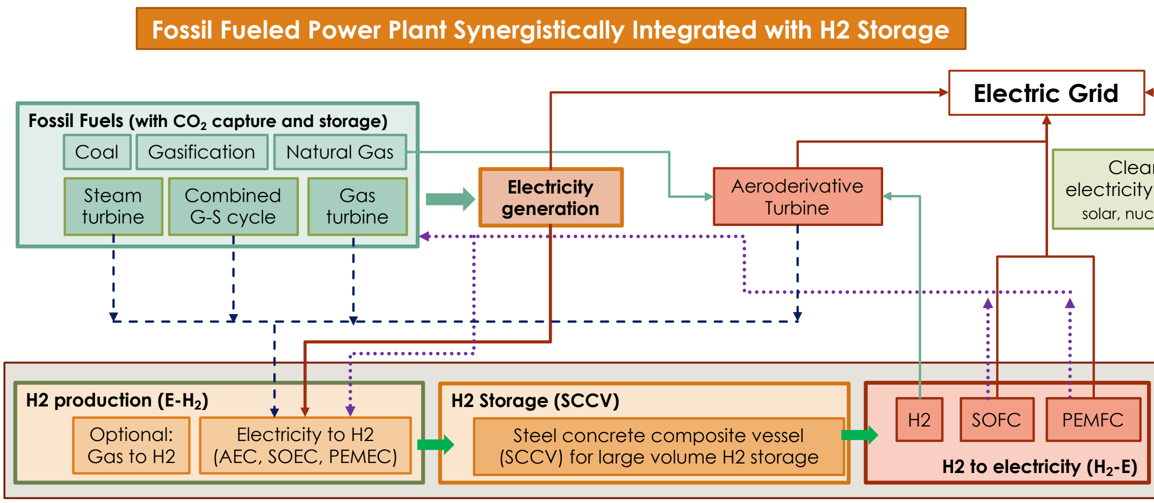

Figure 4 Proposed concept of SIHES integrated with fossil fueled power plant. Dashed lines show flow of the by-product heat from one subsystem to others to improve the overall efficiency of power generation.

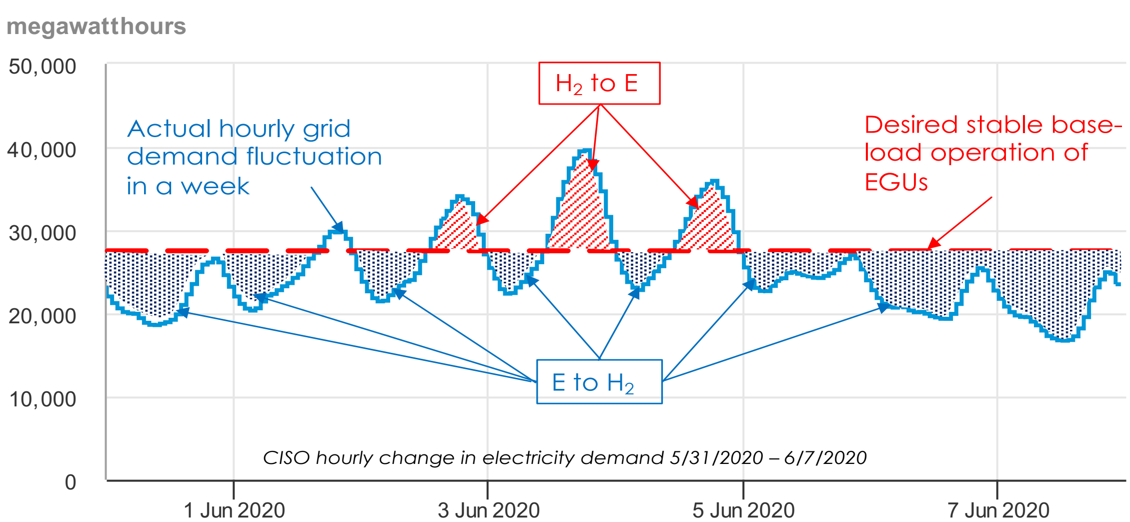

Figure 5 Optimal operation of SIHES to achieve relatively constant baseload operation of EGUs.

As shown in Figure 5, the operational principle of the SIHES is to enable the EGUs to operate at its optimal baseload operation conditions, by a *sufficiently large* hydrogen storage system to manage the dynamic changes in electric grid demand and electricity price over intermediate to long-durations. As such, the EGUs would avoid the frequent, deep cycling that decreases power generation efficiency, accelerates equipment damage/degradation and retirements, and increases operational costs to asset owners and end users.

3.2 Synergistic Integration of E-H_2 Subsystem and H_2-E Subsystem with Fossil Fueled Asset

As shown in Figure 4, several relatively mature technologies for H_2 generation and electricity production are considered for further study in this project. On the E-H_2 side are alkaline water electrolyzer cell (AEC) that are commercially available, proton exchange membrane electrolyzer cell (PEMEC), and solid oxide electrolyzer cell (SOEC). On the H_2-E side, commercially available options include solid oxide fuel cell (SOFC), proton exchange membrane fuel cell (PEMFC), aeroderivative gas turbines and similar types of gas turbines that can utilize mixed hydrogen and natural gas. [14].

It is noted that both E-H_2 and H_2-E processes involve heat or thermal energy – E-H_2 is an endothermic reaction and H_2-E is an exothermic reaction. It is therefore possible to synergistically integrate these processes with the fossil EGUs, from the mass and thermal energy perspective. In order words, the two-way coupling of the "by-product" or otherwise wasted mass and thermal energy between the EGU and SIHES would offer a unique option to greatly improve the round-trip efficiency of hydrogen energy storage *that is not available in renewable energy such as solar and wind*. For example, it is possible to use the excessive low-grade heat from the fossil side to preheat the water used in AEC and PEMEC to 80-90°C to improve the hydrogen generation efficiency. For SOEC, preheating the water to 500-800C using the excessive heat or directly using high temperature steam from EGU would drastically reduce the amount of electricity for hydrogen production. According to International Atomic Energy Agency [15], it is possible to reduce the electricity usage to ~35kWh from 50kWh, or *achieving 90% of efficiency*. Similarly, on the H_2-E side, the heat from H_2-E unit can be used in turbine operation.

There are several specific options to synergistically integrate the heat between the EGU side and SIHES side. These options are presented in Figure 4 using dashed lines to show the flow of by-product heat/thermal energy among the different subsystems of the fossil side and the hydrogen side. The solid lines show the flow of electricity or gas fuel among different subsystems.

In this project, these synergetic hydrogen and power generation options was explored and evaluated and tailored to representative host sites identified by our utility partners.

3.3 Big-Ton: Low-Cost Hydrogen Storage Subsystem

As described above, from the technology point of view, individual sub-systems or components of hydrogen energy storage system are relative mature technologies, at TRL 5-9. They could be integrated meet or potentially meet the energy storage needs of fossil power plants. However, they are not necessarily economically viable, particularly for large scale deployment. For today's hydrogen energy storage, the *added* round-trip (E-H_2-E) cost, at $50-60/MWh LCOE-a, is too high for fossil fueled power plants.

In this project, we plan to utilize the **Big-Ton**, an innovative stationary gaseous hydrogen storage vessel capable of storing 3-15 tons of gaseous H2 (100-500MWh stored energy) per vessel. Big-Ton is based on the steel-concrete composite vessel (SCCV) invented by the PI of the project and patented Oak Ridge National Laboratory (ORNL) [16,17] to drastically reduce the cost of the hydrogen storage system. SCCV technology has been licensed exclusively to WE NEW ENERGY, the lead of this proposal, for commercialization. By optimizing and streamlining the manufacturing processes of SCCV, Big-Ton further reduces the materials and manufacturing cost of SCCV with major cost advantages in the global energy storage market.

Sponsored by DOE Hydrogen Fuel Cell Office, SCCV integrates four major innovations to optimize cost, scalability, durability, and safety. It solved the critical hydrogen embrittlement issue of high strength steels *by innovative patented vessel design*. This allows the use of cost-effective materials such as steels and concrete and mature, code/standard accepted design and fabrication practices and manufacturing technologies to greatly reduce the cost of hydrogen storage vessels. SCCV can be made in the US today, as shown in the photo in Figure 6 – the first of its kind was manufactured in Texas. Also shown in Figure 6, detailed high-fidelity bottom-up cost analysis conducted by ORNL and its pressure manufacturing partners concluded that, if the SCCV vessel is *manufactured in the US,* the costs would be in the range of \$500-\$600/kg H_2 for 875 bar pressure design, which is less than 1/3 of today's high-pressure hydrogen storage [18]. The cost of the SCCV can be further reduced to \$200-300/kg H_2 when global material supply and manufacturing capability are considered. The SCCV technology is scalable in storage capacity and pressure level, especially suitable for bulk, stationary hydrogen storage for fossil power plants. It can be designed and manufactured for very large applications with pressure range from 100 – 1000 bar and > 30 years operation life under cyclic pressure loading conditions. Prefabricated storage capacity is from 100-2000kg H_2 per vessel. Even larger vessels can be constructed on-site, similar to various large pressure vessels manufactured in the US. The SCCV technology has been codified in ASME BPV code (Code Case 2949) in 2019, so it can be designed and constructed per ASME code with mature manufacturing processes. SCCV is at TRL-7 as a sub-system for hydrogen energy storage.

	100 kg	167 kg	200 kg	270 kg	320 kg	500 kg
FSOL	771	639	585	568	574	680
FSLL	765	635	583	566	572	679
ESOL	810	669	660	613	604	707
ESLL	805	665	658	611	603	706

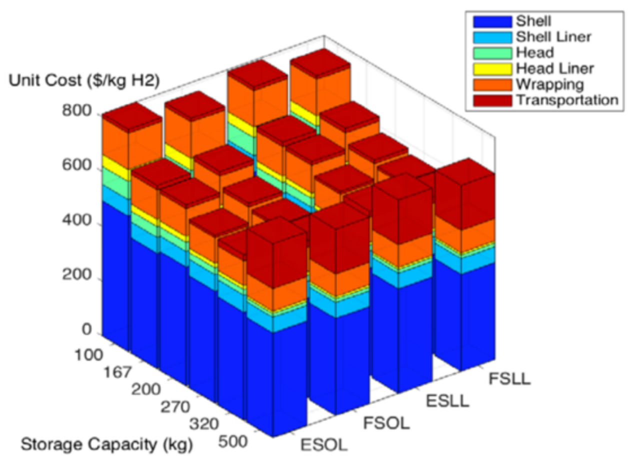

Figure 6 Hydrogen storage vessel cost of ORNL GEN II SCCV technology [18]. The photo shows a SCCV is being manufactured in a vessel company in Taxes.

We conducted a preliminary techno-economic case analysis for tailored use of Big-Ton in SIHES. It was found that such a solution is not only technically feasible, but also economically very attractive, for long term (>24 hour to weeks) grid scale storage. The case study considered a SIHES consisting of AEC, Big-Ton, compressor, and PEMFC as the baseline subsystems, for a generic 10MW power and 7-day storage scenario for 30-year service. Our preliminary analysis included conceptual improvement to Big-Ton to tailor its use in SIHES, other relevant changes and adjustments to other sub-system/components, and the overall SIHES system design for economic considerations. As shown in Figure 7, replacing today's pressure vessel, at approximately \$1150-1400/kg H_2 [4], with Big-Ton would result in a projected drastic reduction in the capital cost of the storage subsystem, from over 70% to about 35% of total capital cost of the system. It is noted that our analysis for the baseline with today's hydrogen vessel is consistent with the findings by Penev et al [9].

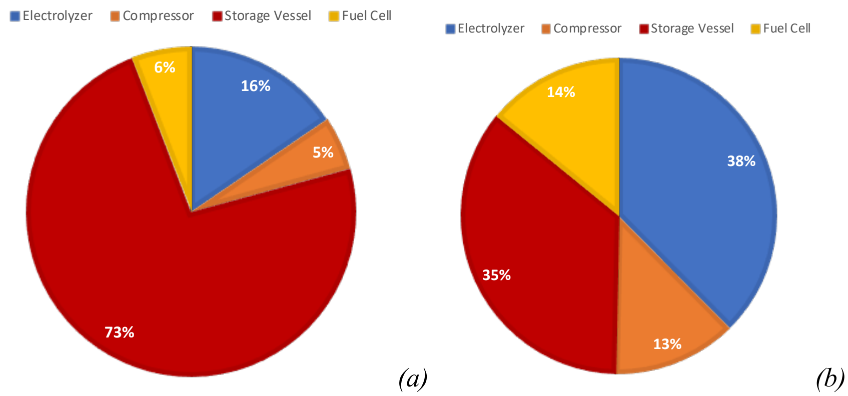

Figure 7 Cost breakdown of hydrogen storage system: (a) baseline existing vessel technology at $50-60/MWh added LCOE, (b) our patented SCCV at $5-20/MWh added LCOE. Basis for analysis:10MW, 7-day storage.

3.4 Putting Pieces Together

As discussed in previous sections, hydrogen based long duration storage solutions are technically feasible, but economically challenging at $50-60/MWh of *added* LCOE. Our proposed research aims to address this challenge, by developing the SIHES to significantly reduce the cost of hydrogen energy storage. The cost <u>target is less than 10% LCOE of today's fossil fueled assets,</u> to achieve the expected economic viability.

The proposed SIHES consists of the following three key technology innovations targeted for economic viability for deployment with fossil fueled assets:

- *<u>Drastically reducing cost of hydrogen storage subsystem</u>*. The cornerstone is our patented Big-Ton ultralow cost steel concrete composite vessel. It will be further developed for tailored use in SIHES. The use of Big-Ton in SIHES is expected to lead to relevant changes and adjustments to other sub-system/components, and the overall SIHES system design for economic considerations
- *<u>Effectively integrating hydrogen energy storage system into fossil assets</u>*. Considerable room exists in optimal integration of E-H_2, storage, and H_2-E into fossil assets. For example, *synergistic* mass and heat integration between the fossil EGU and the hydrogen energy storage systems while considering the asynchronous nature of E-H_2 operation and H_2-E operation can best utilize available energy assets. Optimal integration strategies depend on the types and size of the specific fossil asset, which will be studied in this project with input from utility operators in the project team.
- *<u>Techno-economic optimization</u>*. Due to the transient nature of the storage system as well as the highly dynamic electricity demand and price, techno-economic optimization of the integrated system with due consideration of these dynamics is considered to be critical to maximize the economics of the proposed hydrogen storage system. Optimization of both design and operating variables will be undertaken in this project.

4 PHASE I CONCEPTUAL STUDY

4.1 Identification and Assessment of Early Adoption Target Site

In Phase I, we worked with our industry partners Exelon and TVA to select candidate fossil plant sites for the development of SIHES technology. Exelon recommended two candidate sites for consideration: (1) Mystic Generating Station near Boston, MA, and (2) Southeast Chicago Energy Project Generation Station near Chicago, IL. The locations and layouts of the two sites are shown in Figure 8.

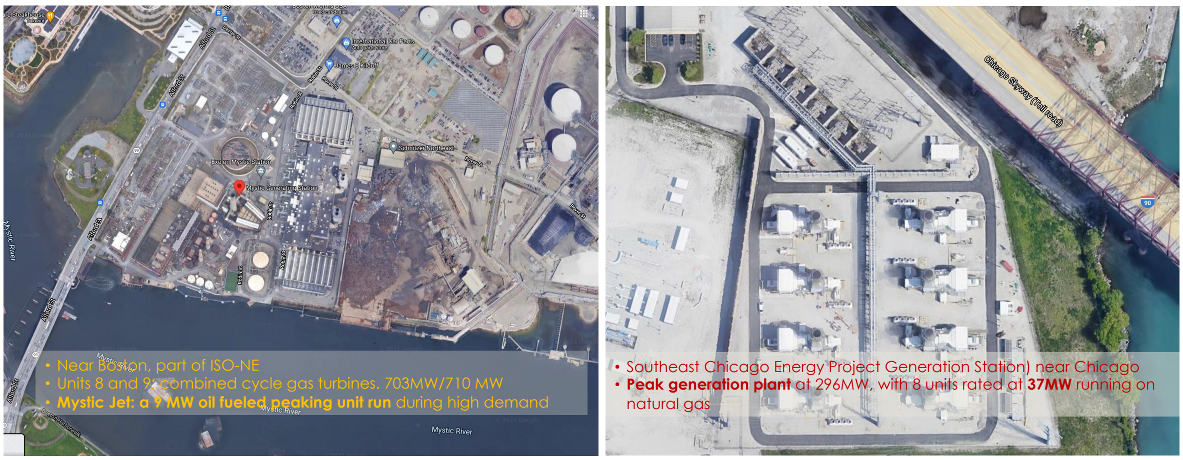

Figure 8 Left: Mystic Generation Station near Boston. Right: Southeast Chicago Energy Project Generation Station

The Mystic Generating Station is part of ISO-NE and has the highest nameplate capacity of any stations in the state. It uses both natural gas and petroleum as fuel, but mostly burns natural gas. The two units Mystic 8 and 9 are combined cycle natural gas units with a total of four combustion turbines and two steam turbines which can produce 1414 MW total. These two units are baseload power generation units, but subject to considerable load variations. In addition, the plant has a small oil fueled peaking unit (Peaker) which produces 9 MW in periods of high demand.

Southeast Chicago Energy Project Generation Station is an 8-unit, 296-megawatt, natural gas-fueled facility. These units are Peakers as they are used for peak demand periods and load balancing. Each unit is rated at 37MW.

The above two candidate sites represent two very different but important use cases for potential adoption of SIHES as long-duration hydrogen storage solutions.

In addition to Exelon, we also engaged with TVA**,** which is the electricity provider for the project lead WE New Energy. TVA operates 101 natural gas- and fuel oil-fired generators at 17 sites. In 2020, natural gas account for 23 percent of TVA total electricity generation. Recommendations from TVA were similar to Exelon, in terms of the general adoption needs and strategy. In addition, both Exelon and TVA are particularly interested in the SCCV technology for its potential to reduce the cost in long-duration storage.

Upon reviewing and analyzing the operation histories of recommended plants from both utility partners, and electricity market price (LMP) fluctuations over short term (days) and long-duration (weeks to months), we identified a meaningful strategy for early adoption of SIHES in fossil plant sites.

The strategy is to use SIHES as peaking power generation units (so named as HyPeaker) as the first market entry point. The learnings from these early adoption efforts would help further advance the technology and gain market confidence and acceptance to add larger SIHES to baseload power plants at hundreds MW to GW level.

The selection of peakers as the first targeted early adoption is based on the following considerations.

- Today's natural gas and oil peakers are generally more expensive and inefficient to run, on MWh basis, than the baseload plants. They also emit higher rates of CO_2 and health-harming air pollutants. Therefore, there are considerable economic and environmental incentives to replace them and/or supplement with clean power storage and generation technologies such as SIHES.
- Today's peaker plants are typically disproportionately located in disadvantaged communities, such as urban centers and in low-income and minority communities, where vulnerable populations already experience high levels of health and environmental burdens. There would be significant societal benefits to replace oil and gas-fired peaker power plants with clean ones.
- Compared to baseload power plants, the sizes or capacities of the peakers are much smaller. As such, challenges to design and construct the first HyPeaker unit, from both technical and capital investment perspective, are much more manageable.
- The operational and grid characteristics of peakers lend them to a prime candidate for hydrogen system such as HyPeaker. Peakers run infrequently and are brought online to help deliver electricity during periods of high peak demand. They are only used for a few hours at a time, typically running less than 10-15% of the time (capacity factor), often as low as 1-3%. Such low-capacity factor and intermittent operation offers the flexibility for optimal HyPeaker design. By oversizing our unique low-cost high-pressure SCCV hydrogen storage vessels, it is possible to significantly reduce the capital and operational costs of HyPeaker system.
- United States currently have more than 1,000 natural gas- and oil-fired peaker plants across the country. This represents a sizable potential market for the deployment of hydrogen-based energy storage system in next 5-10 years.

Therefore, HyPeakers provide a unique opportunity to strategically displace some of the most polluting electricity power generation units on the grid, to yield the greatest health, environment and equity co-benefits.

4.2 Conceptual Design of HyPeaker

Communications and inputs from Exelon and TVA led to the following conceptual design of HyPeaker. The steps and rational for the conceptual design are:

- Step 1: Decide on the electricity generation capacity of a HyPeaker. The conceptual design settled on 50MW, which was in the range of electricity power output from today's natural gas peakers. Both Exelon and TVA suggested considering natural gas combustion turbines instead of using hydrogen fuel cells for electricity generation. Furthermore, it was recommended to use mixed hydrogen and natural gas as fuel, initially up to 20% vol of H_2 in the blend. This makes it possible to use existing gas turbines with retrofitting/modifying the ignition and control units for mixed H_2/NG fuel, to lower the capital cost and technology risk. The design of the HyPeaker system does have an option to deploy PEM based hydrogen fuel cell for electricity generation in future, once the utility-scale PEMFC matures in capacity and becomes cost competitive.
- Step 2: Decide on the size of hydrogen storage subsystem and its pressure level. We purposely over-sized the capacity of ultra-low cost Big-Ton – It should store sufficient hydrogen for up to 20 hours of operation, i.e, sufficient for two 10-hour continuous operation of peaking power generations without the need to refuel in between. This was based on the consideration of (1) providing the extra storage capacity to take advantage of low electricity price over a long period of time such as in several weeks or even longer, (2) reducing the hydrogen generation capacity of the electrolyzer which is the highest cost item in the system. This led to a 200MWh (6000 kg H_2) and 3000 psi Big-Ton storage subsystem design.
- Step 3: Hydrogen production unit from electricity: Alkaline type electrolyzer. It was rated at ¼ to 1/3 of electricity generation capacity by taking advantage of oversized hydrogen storage capacity.

In summary, Phase I HyPeaker design metrics for fossil plant from Phase I study are:

- Electricity generation capacity rated at 50MW using combustion turbine powered by mixed H_2 and natural gas, initially with 20% of H_2
- Hydrogen storage system: Big-Ton vessels rated at 3000psi pressure, with storage capacity of 200MWh (6000kg) hydrogen
- Alkaline type electrolyzer for hydrogen production: rated at 12 to 15MW.
- The operation of HyPeaker: use the excessive electricity from baseline fossil units when the demand of electricity is low, and supply electricity to the grid at the peak demand when the electricity price is high. The price fluctuations due to grid electricity demand changes would be an important consideration in the deployment of the HyPeaker for power generation plants.
- The design of HyPeaker allows for additional modules of Big-Ton vessels and/or electrolyzers be added in future phases to accommodate higher percentage of H_2 in the mixed gas for combustion turbines.

4.3 Phase I Technoeconomic Study

In parallel to the above conceptual design study of a site-specific HyPeaker, Phase I also carried out a preliminary technoeconomic analysis (TEA) for more generic HyPeaker designs using software CAPCOST [19]. Since this analysis was done in parallel, some system design assumptions in TEA were different from the above site-specific conceptual HyPeaker design. Nevertheless, the Phase I TEA provided the insights to the economical aspect of SIHES that were important to consider in HyPeaker design optimization in Phase II.

Economics are compared with a 50 MW net duty peaker plant fired with natural gas. It is assumed that the hydrogen production unit (electrolyzer) operates only when the locational marginal price (LMP) is low while the electricity generation unit (fuel cell or combustion turbine) operates when the LMP is high. For the base case of the integrated H_2-based process, it is assumed that the polymer electrolyte membrane (PEM) fuel cell costs \$300/kW and alkaline electrolyzer costs \$400/kW – both on the low end of system costs projected for next 5-10 years. The fuel cell capacity is the same as the peaker, i.e., 50 MW, with an energy efficiency of 65%. Electrolyzer energy efficiency is assumed to be 70% and its capacity is calculated by considering the number of hours of operation of the fuel cell and electrolyzer such that the amount of H_2 needed in the fuel cell can be produced by the electrolyzer. H_2 storage volume is calculated by considering the design pressure and duration of fuel cell operation. Taxation rate and internal hurdle rate are specified to be 45% and 10%, respectively. A plant life of 20 years is considered. It is assumed that the construction can be completed within 1 year and all capital investments are made in that year. Depreciation is considered to be linear over the plant life.

Since the addition of H_2-based technologies would add capital cost and operational cost in absence of carbon tax, or similar CO_2 trade credit, energy arbitrage on both daily basis and seasonal basis would be an important variable to consider for improving or maximizing the economics of H_2 based energy storage system. The operating costs for the electrolyzer and H_2 compressor from electricity consumption would be minimized when the LMP is low, while the revenue from electricity generation would be maximized when LMP is high. It is also important to recognize that the durations of low LPM and high LPM are also important when properly sizing the H_2 production capacity of electrolyzer and energy storage capacity of SCCV. For this purpose, we introduced a new parameter in our TEA: ΔLMP*hours (\$/MW), which is defined as (high LMP (\$/MWh) *high LMP duration (h)-Low LMP(\$/MWh) *Low LMP duration(h)). We studied the sensitivity of NPV to this new parameter.

LMP data from ISO-NE were collected and analyzed in our TEA. As an example, Figure 9 shows the LMP historic data for the week of Oct 10, 2021. The one-week data were averaged to obtain mean LMP, which is used to determine the time periods for H_2 production, electricity generation or idling when neither the electrolyzer nor fuel cell or combustion turbine operates in our TEA.

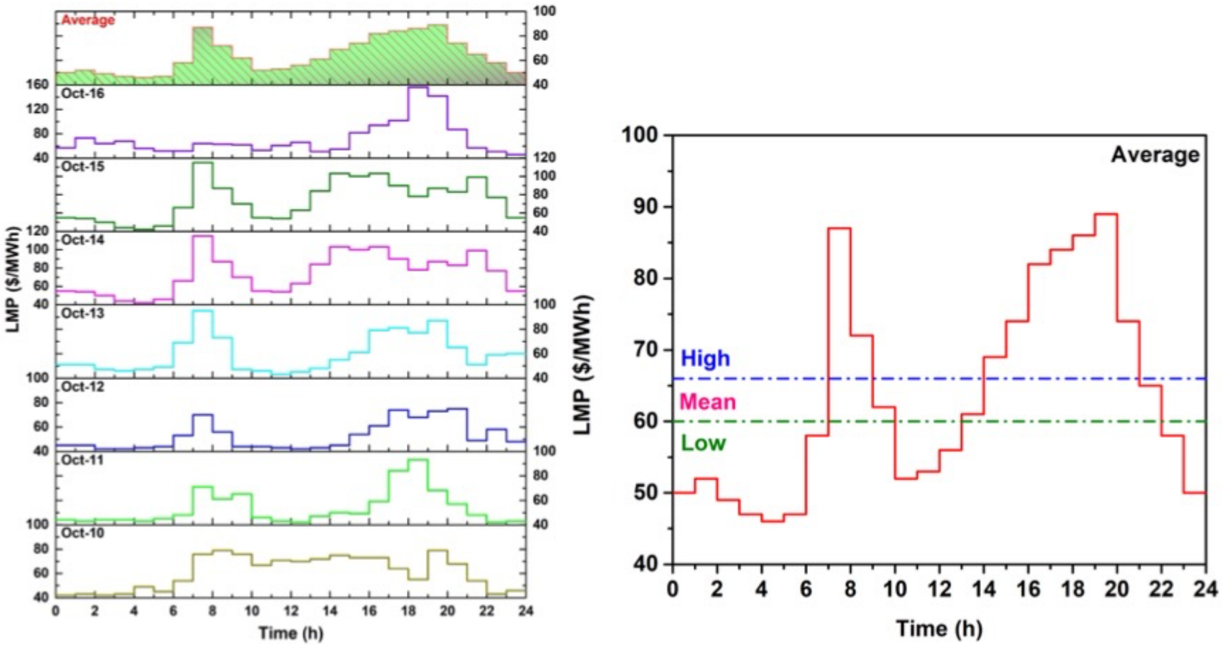

Figure 9 LMP price in week of Oct 10, 2021 in ISO-NE area. Mean hourly LPM variation is divided to high range for electricity generation, and low range for H2 production. Between high and low, the system is idle due to economic considerations.

In the results presented below, this range is +/-10% of mean LMP. High LMP is assumed to be when the LMP is higher than mean LMP+10% LMP. Time averaged value of high LMP is obtained based on the high LMP and its duration. Time averaged value of low LMP is also obtained in the similar manner. Other operating costs such as those for the labor, operation &maintenance, operating and laboratory supplies, administrative costs are left at their default value in CAPCOST. It is noted that in CAPCOST, these costs are calculated as a percentage of the capital costs, raw material costs, etc. As the electrolyzer and fuel cell costs are highly uncertain at this point due to lack of commercialization, sensitivity studies are undertaken to evaluate the impact of costs of fuel cells and electrolyzers on net present value (NPV) by changing their costs from 10% to 150% of the base case value. In the proposed technology, there is an efficiency loss while converting electricity to H_2 in the electrolyzer including the compression cost for storage as well as efficiency loss while converting H_2 back to electricity in the fuel cell or combustion turbine.

To analyze the potential benefits of the low cost SCCV technology on the NPV, economics are compared for three cases- conventional storage for compressed H_2, current SCCV technology, SCCV technology with 50% cost reduction which is expected to be achievable through tasks undertaken in Phase II and beyond. NPV of the current NG-fired peaker is analyzed using the same economic specifications as above, but assuming that the capital costs have been depreciated. Therefore, only operating costs are considered. For computing the peaker revenue, high LMP and its duration are considered to be the same as that for the fuel cell for the H_2-based power generation.

Figure 10 shows the NPV corresponding to the conventional storage technology. For the entire range of variables that are evaluated, NPV remains negative and therefore this technology is currently not a viable investment. On that same figure, NPV of the current NG-fired peaker is also shown that shows a NPV of about $50M. While the NPV for the peaker can greatly vary depending on the rating of the peaker, capital expenses of the peaker and other costs that may not have been accounted for in the current calculations, but since all calculations are done using same assumptions and specifications, the results presented in this figure is still meaningful clearly showing the significant difference in the economics of the two technologies.

Figure 11 show the ΔNPV, i.e., differences in the NPV between the SCCV H_2 storage technology and conventional H_2 storage technology (using a cost of $1100/kg H_2 for storage cost). Two cases of SCCV cost were considered: (1) the current storage cost of \$300/kg H_2 results in ΔNPV as high as \$100M. (2) projected SCCV cost of \$150/kg H_2 with even higher ΔNPV.

In summary, TEA undertaken in Phase I so far shows that the storage costs are expected to play an important role in the economics and the SCCV storage technology can considerably improve the economics compared to the existing compressed H_2 storage technologies. Several assumptions have been made in generating the resulted presented above, as the first step in TEA modeling of HyPeaker. These assumptions will be further evaluated and adjusted in the comprehensive TEA in Phase II.

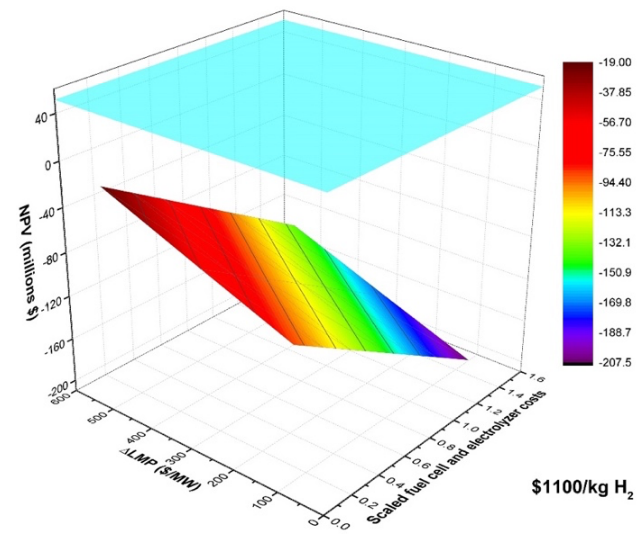

Figure 10 NPV of the integrated H_2 generation, storage, and H_2-based electricity generation process for the conventional compressed H_2 storage (scaled value of 1 for the fuel cell and electrolyzer represents base case costs)

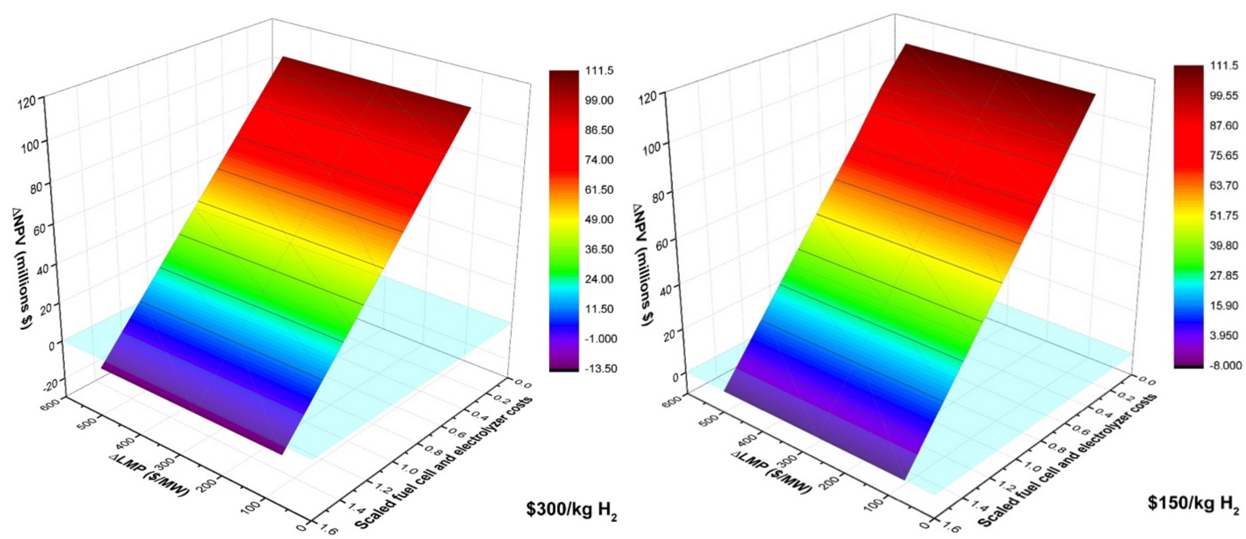

Figure 11 NPV of the integrated H_2 generation, storage, and H_2-based electricity generation process. Left: for the currents SCCV cost; Right: for future projected SCCV cost

5 PHASE II PRE-FEED STUDY

In Phase II, preliminary front-end engineering design (Pre-FEED) study is carried out to further develop a HyPeaker for a specific fossil power plant site. The HyPeaker is optimized to achieve both technical feasibility and economic viability. Achieving the Phase II technical and economic objectives would build the foundation for the subsequent site demonstration, and eventual wide-scale deployment of SIHES technology in fossil power generation plants.

The HyPeaker system design and engineering comprises the following major steps.

Step 1 – Finalize selection of fossil asset site

Step 2 – Initial design and engineering of sub-systems and key components (Level I Design)

- Size up H_2-E sub-system to meet site specific gas turbine operation requirements
  - Power, duration and capacity factor requirements
  - Site-specific electricity and fuel cost structure
- Size up H_2 storage sub-system to meet H_2-E sub-system requirements
  - Storage capacity (kg of H_2, pressure, size, cost)
  - Compressor (pressure, throughput, cost)
- Size up E-H_2 electrolyzer sub-system based on H2 storage and gas turbine operation profile
  - Capacity, cost

Step 3 – Complete initial specification of entire HyPeaker

Step 4 – Obtain prices and costs of major components/sub-systems from potential suppliers and vendors

Step 5 – Optimize entire HyPeaker system level for total cost and performance (Level II optimization)

Step 6 – Complete Pre-FEED systems design and component specifications

5.1 Selection of a Fossil Asset Site

Several candidate fossil sites for HyPeaker were reviewed and studied together with the project utility team members. TVA's Johnsonville Combustion Turbine Plant was down selected as the site for the site-specific HyPeaker development. The Johnsonville Combustion Turbine Plant sits on 700 acres in Humphreys County, TN., in the town of New Johnsonville. It features 20 General Electric simple-cycle combustion turbines. The combustion turbines have a combined generation capacity of 1,269 MW (65MW per unit). The plant is modernized with new General Electric's LM6000 aeroderivative gas turbines to replace the old simple-cycle combustion turbines. The first set of LM6000 units is scheduled to be operational in 2024. Therefore, the Pre-FEED study focused on integrating the hydrogen energy system to a LM60000 unit.

Figure 12 is an aerial view of the Johnsonville plant site. The site for H_2 production and storage is marked by the green color box, and the site for the new LM6000 units is marked by the red color box. The hydrogen production and storage sub-systems is on an old coal-ash storage site for the coal fired baseload units which were dismantled a few years ago. It has been cleaned up and ready for other uses. This location is selected based on the following considerations.

First, it is large enough for both H_2 production electrolyzers and Big-Ton H_2 storage sub-systems.

Second, it is in proximity of the new LM6000 units, yet with sufficient distance to meet hydrogen storage safety regulatory requirement. A small diameter stainless steel pipe (2-3 inch in diameter) runs between the H_2 storage site to the LM6000 site. H_2 would be pre-mixed with the natural gas at the LM6000 site where the natural gas line is located. The H_2 pressure in the pipe connecting the two sites is maintained at 700psi, the same as the feeding pressure of natural gas to the gas turbine. Valves and regulators are used to maintain the pressure in the H_2 pipe at 700psi, and to regulate the mixing volume ration at predetermined levels. As the pressure in the Big-Ton H_2 storage vessel is designed at 3000psi and multiple vessels are used to feed H_2 cascadingly, no H_2 compressors are required to feed H_2 from the storage vessel to the H_2/natural gas mixing unit..

Third, there is already a water purification system in operation near the proposed H_2 production and storage site. The water purification system takes the water from the nearby river and purity them for a chemical plant nearby. Owned by TVA, this water purification system has sufficient capacity to provide the purified water to the electrolyzer for H_2 production.

Finally, the high-temperature exhaust gas from the LM6000 unit can be utilized to pre-heat the water to increase the efficiency of H_2 production from the alkaline electrolyzer. According to literature, this would lead to 4-8% increase in efficiency, when the water is preheated to near the boiling point of the water. The pre-heated water can be stored over several days or weeks. This aspect is not included in the Pre-FEED study, but planned for further evaluation in the next phase.

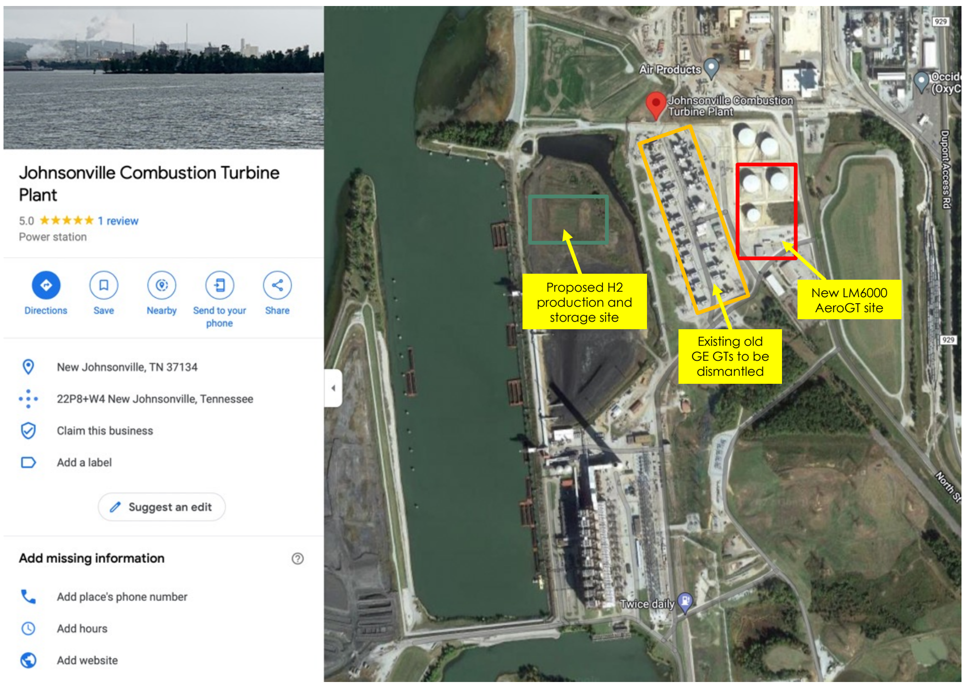

Figure 12 Aerial view of TVA's Johnsonville Combustion Turbine Plant per Google Map

5.2 Initial Design of HyPeaker (Level 1 Baseline Design)

The initial design of HyPeaker sub-system involved the following aspects:

- Reviewing the available energy assets and requirements from both the energy storage side and fossil asset side to refine the baseline energy storage requirement
- Developing an integrated process description to connect the major subsystems (hydrogen production, storage, and electricity generation) and key connecting component and methodology.
- Providing metrics for optimization and sensitivity study of the integration options leading to the optimal design specific to the Johnsonville site.

The basic principle in designing a HyPeaker is that it must supply sufficient hydrogen, in the most economical way, to power the peaking electricity generation unit (LM6000 in this study). As in the case of regular peaking power generation units, it is expected that the operation of HyPeaker would be dictated by fluctuation of electricity demands on the market and vary greatly from time to time. Therefore, the design of HyPeaker would be based on the *future* operation profile *projected* by the utility owner. Accordingly, the initial design and engineering of sub-systems and key components (Level 1 design) logically follows the sequence of:

- Size up H_2-E sub-system to meet site specific gas turbine operation projections
  - Power, duration and capacity factor requirements
  - Site-specific electricity and fuel cost structure
- Size up H_2 storage sub-system to meet H_2-E sub-system requirements
  - Storage capacity (kg of H_2, pressure, size, cost)
  - Compressor (pressure, throughput, cost)
- Size up E-H_2 electrolyzer sub-system based on H2 storage and gas turbine operation profile
  - Capacity, cost

Figure 13 shows the high-level block flow diagram for Level 1 initial design of the HyPeaker. Also indicated in the figure is that the initial baseline design of the HyPeaker is not expected to be optimal. Indeed, it is just the initial reference point in the Pre-FEED process to facilitate comprehensive evaluation of the technology readiness level or maturity of all sub-systems and components of the HyPeaker, and to obtain quotations on cost and specifications from sub-system and component manufacturers and suppliers. It also serves as the basis for the Level 2 system level optimization for cost and performance described in Section 5.4.

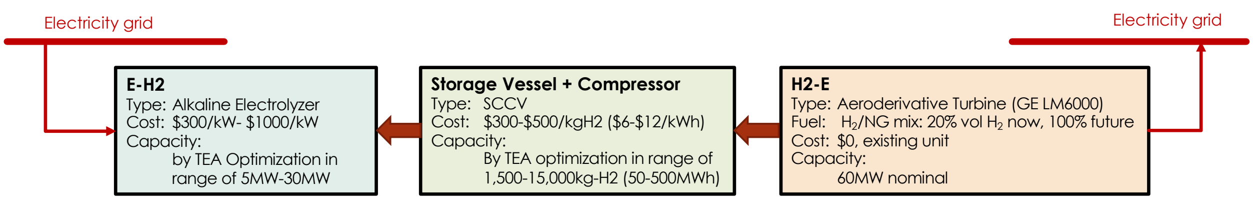

Figure 13 HyPeaker design flow in Level I baseline design

5.2.1 Baseline Engineering Design for H_2-E Sub-System

The aeroderivative gas turbine already available at Johnsonville site is selected for electricity generation. TVA provided the following specifications:

- A GE LM6000 aeroderivative gas turbine:
  - Rated power: 60MW
  - Projected operational power range: 47-55MW
- Blend H_2 with natural gas fuel to power LM6000
  - 20% volume of H_2 in H_2/natural gas blend for Pre-FEED study. Option to increase to 100% H_2 in future but not included in Pre-FEED.
  - Pressure to the turbine: 800psi.
- Projected Operation Profiles
  - TVA provided the hourly operation profiles projected for 10 years. The proprietary profiles include the hourly variations in both electricity generation cost and power output levels. They are used to drive the Level II design optimization of HyPeaker. They are not for public release. Nevertheless, the projected operation profiles have the following general characteristics:
    - The capacity factor of the aeroderivative gas turbine varies considerably from year to year. It ranged from 10-12% in heavy duty years, 5-6% in average duty years.
    - For a given year, the capacity factor also varies considerably between season, months, and weeks, to 1-2% in light duty years.

  - Summer has longest operation hours: up to 14 hours per day, and often between 8-12 hrs per day.
  - Winter has shorter operation hours: up to 5 hrs/day and often between 3-5 hrs per day
  - Spring and Fall: rarely
- To avoid overly expensive design, the HyPeaker could be designed such that H_2 just needs to be available for 80-95% of operational hours. The remaining operations can use 100% natural gas, by taking advantage of fuel flexibility of LM6000.
- HyPeaker is designed for 30-year operation lifetime.

5.2.2 Baseline Engineering Design of H_2 storage sub-system

The baseline H_2 storage sub-system is to have the storage capacity to allow a LM6000 unit running continuously for 14 hrs – the longest continuous operational hours of LM6000 in a given year.

- 14 hrs @ 57.7MW capacity: 808MWh electricity generated
- 38.5% thermal efficiency: 2,098MWh fuel consumption
- Energy content and gas density of H_2 and natural gas:
  - H_2: 145kWh/m^3; Natural gas: 543kWh/m^3 at 800psi, 25C
- 20% vol H_2 mix @800psi
  - 280 kg-H_2/hr, or 4000 kg-H_2 for a 14hr operation day.
- Size of vessel
  - The size of the vessel is generally constrained by means of transportation to ship the vessels from the manufacturing sites to Johnsonville, TN. The Johnsonville plant is on the bank of Tennessee River which is connected to major waterways and Gulf of Mexico. Large sized vessels can be transported to Johnsonville site via barge. In addition, Johnsonville plant has access to railroad transportation. As such, the weights of a vessel would be in the range of 100 ton to 200 tons. Another constraint is lifting capacity of a manufacturer to load the vessel to railroad car or ocean ships/barges, which can vary by manufacturers.
  - Another factor to consider is cascading feeding of H_2 from multiple vessels to the gas turbine feedline
  - This leads to the baseline design of 3-4 vessels with each vessel containing 1000 to 1500 kg H_2 at 3000psi.
- Compressor
  - High-throughput H_2 compressors are required to pump the hydrogen from electrolyzer to the hydrogen storage vessels. The pressure of H_2 will be increased from 150psi (typical electrolyzer outlet pressure) to 3000psi (storage pressure), at rate of 280-300 kg-H_2/hr.
  - With multiple vessel option, it is possible to have multiple compressors with reduced throughput capacity, such as two 125kg-H_2/hr compressors operating simultaneously to fill two vessels at the same time.

Based on the above analysis, the following design and manufacturing specifications were used to obtain H_2 pressure vessel manufacturer's budgetary estimate and quotations:

- Storage vessel: 3000psi pressure at 0-100F, 4000 kg H_2 total. 30 years operation lifetime.
- Compressors: compressing H_2 from 150psi to 3000psi at rate of 300 kg-H_2/hr total. 10 years operation lifetime.

5.2.3 Baseline Engineering Design of E-H_2 Electrolyzer

For baseline design, the requirement of electrolyzer is to produce 4000 kg-H_2 in a day to meet the need during the longest continuous operation of electricity generation unit (LM6000), which is 14 hrs for the Johnsonville site. Since H_2 should be produced using the excessive electricity outside the peak hours, the electrolyzer could only run for 10 hours during these busiest peaking days when the demand for H_2 is highest. As such, the electrolyzer needs to have the capacity of producing 400 kg-H_2/hr. The capacity requirement for the alkaline electrolyzer selected in this project would be 24MW, based on 55% efficiency.

It should be noted that the above baseline capacity requirement of electrolyzer needs to cover the extreme scenarios when the electricity power generation unit (LM6000) runs at its longest hours and the electrolyzer runs at its shortest available hours in a day (barring any electricity price or fuel cost restrictions which may even further shorten the run hours of electrolyzer in a day). As peaker's operation varies greatly especially between weeks even months, there will be days when the electrolyzer can run longer than 10 hours. Thus, it is possible to reduce the capacity and the cost of electrolyzer from 24MW to run it longer when the demands for electricity usage is low and the electricity price is low. However, this would require oversizing the hydrogen storage sub-system – thereby increasing in cost – to balance the production and utilization of H_2 over days even weeks. This aspect is further studied in Level II engineering design and TEA optimization of the entire HyPeaker system which requires the cost information of major components (Section 5.3) and projected operation profile of HyPeaker (Section 5.2.1). The Level II optimization is described in Section 5.4.

5.2.4 Baseline Specification of HyPeaker

In summary, the baseline design specification of the site-specific HyPeaker for Johnsonville site consists of

- H_2-E subsystem:
  - General Electric LM6000 aeroderivative gas turbine rated at 60MW. Mixed H_2/Natural gas fuel with 20% vol H_2 at 800psi.
- Hydrogen storage subsystem:
  - Storage vessel: 3000psi pressure at 0-100F, 4000 kg H_2 total. Multiple vessels for cascading operation. 30 years operation lifetime.
  - Compressors: compressing H_2 from 150psi to 3000psi at rate of 300 kg-H_2/hr total. 10 years operation lifelife.
- E-H_2 subsystem:
  - Alkaline Electrolyzer: rated at 24MW. 10 years operation lifetime (~90,000 hrs) at 100% utilization rate.

5.3 Prices and Costs of Major Components/Sub-systems from Suppliers and Vendors

5.3.1 Electricity Generation Unit

The electric generation unit of HyPeaker would be General Electric's LM6000 aeroderivative gas turbine which is capable of using mixed H_2/natural gas fuel. According to General Electric, LM6000 could require modification of fuel injection system only if H_2 is higher than 20% vol in the mixed fuel. By limiting the volume percentage of H_2 to 20% in our design, the cost for system modification was also avoided. Since the Johnsonville site already had LM6000, the capex if LM is not included in the cost of HyPeaker.

5.3.2 Hydrogen Storage Vessels

The Big-Ton hydrogen storage vessels based on the innovative SCCV technology will be used for hydrogen storage. We contacted multiple potential storage vessel manufacturers, both domestically and overseas, for budgetary estimate and quotations to manufacture Big-Ton based on our patented design. We received the quotes from pressure vessel manufacturers in the US, in South Korea, and in China. All manufacturers have ASME BPV design and manufacturing certificates to design and manufacturer high pressure vessels for hydrogen storage based on our design requirements and specifications. The cost including transportation cost to the Johnsonville site ranged from \$300-800/kg-H_2. These quotes were consistent with the cost estimate in the past [18]. In addition, we received budgetary quotes of the "standard" vessels for hydrogen storage per ASME BVP code from the manufacturers who had the capability to do so.

Budgetary quotes are for a total of 5000kg H_2, including the transportation cost to Johnsonville Power plants from the site of manufacturing. They varied considerably:

- Big-Ton vessel:
  - 1,600,000 total for 5 vessels at 1000kg H_2 each. \$320/kg-H_2. Final assembly in the US, with best materials and subcomponents sourced globally that meet relevant ASME/ASTM code requirements.
  - 2,500,000 total for 5 vessels at 1000kg H_2 each. \$500/kg-H_2. Final assembly in the US, with majority of materials and subcomponents from US suppliers that meet relevant ASME/ASTM code requirements.
- Standard pressure vessel for H_2 storage
  - \$12,500,000 total, for 3 vessels at 1500kg H_2 each from a US manufacturer. \$2780/kg-H_2.
  - \$6,000,000 total, for 5 vessels at 1000kg H_2 each from a manufacturer in South Korea. \$1200/kg-H_2.
  - \$4,000,000 total, for 3 vessels at 1500kg H_2 each from a Japan/China joint venture manufacturer in China. \$900/kg-H_2

5.3.3 Hydrogen Compressors

Many manufacturers for high-pressure hydrogen compression only make compressors at much lower rates for H_2 refueling stations that have rated throughputs of a few hundreds of kg H_2 per day. Technologies and manufacturers are limited for high-pressure high-volume compressors for H_2. The most suitable technology for our applications (in the range of 200-300kg H_2/hr) are diaphragm type of reciprocating compressors. We were not able to receive quotes from US domestic manufacturers for the pressure and throughput range of HyPeaker. Instead, we received quotes from the following international manufacturers:

- A German manufacturer with US Office: \$2,000,000 for a 4-stage compressor from 100 psi to 3,000psi pressure, rated at 245 kg-H_2/hr throughput. \$8000/kg-H_2/hr
- A Chinese manufacturer with US Office: \$990,000 for 5 units from 100 psi to 3,000psi pressure, rated at 300 kg-H_2/hr total. \$8000/kg-H_2/hr. \$3300/kg-H_2/hr

5.3.4 Electrolyzer

We reached out a number of electrolyzer manufacturers for quotes on system and budgetary estimate. They included both Alkaline electrolyzer and PEM electrolyzer manufacturers. Alkaline electrolyzer has substantial advantages in both price and capacity over PEM electrolyzer. So, we focused on Alkaline electrolyzer in our study. Similar to other components, the price and delivery time of electrolyzer varies considerably from one manufacturer to another. The most expensive quote was from a US manufacturer, at \$1000/kW for capacity greater than 1MW. Another US manufacture provided a quote of ~\$500/kW. The system was assembled in the US with components sourced internationally. Finally, a China/European joint venture manufacturer provided a quote of \$350/kW, for the system assembled in China.

Table 2 summarizes the cost of major components of HyPeaker for the baseline design above, based on the capacity of each component and cost information quoted from manufacturers and suppliers. Clearly, at \$12M, the electrolyzer accounts for 80% of the total cost of the baseline design. The total cost of major components is \$15M. We also did a preliminary LCOE estimate for an "average" peaker utilization year (6.45% CF). With a 30-year 3% interest rate of debt, the added LCOE (LCOE-a) would be \$360/MWh. Clearly, such LCOE-a is too high to be considered economically viable. This led to a concerted effort to optimize the HyPeaker design to reduce its total cost, as described in next section.

Table 2 Cost of major components of HyPeaker (baseline design)

	Type	Capacity	Unit Cost	Cost	% total cost
Electricity production	LM6000	57.7MW	N/A	Not included	
H_2 storage	Big-Ton	4,000kg	\$500/kg-H_2	\$2,000,000	13.33%
Compressor	Diaphragm compressor	250kg-H_2/hr	\$4000/kg-H_2/hr	\$1,000,000	6.67%
H_2 production	Alkaline Electrolyzer	24MW	\$500/kW	\$12,000,000	80.00%
Sub Total				**\$15,000,000**	

5.4 Level II Engineering Design and TEA Optimization of Entire HyPeaker System for Total Cost and Performance

In the baseline design of site-specific HyPeaker, the alkaline electrolyzer accounts for 80% of the total system cost. As the cost of electrolyzer is directly related to its capacity, a primary objective of the Level II system design is to reduce the capacity of electrolyzer. This is possible by our innovative Big-Ton high-pressure H_2 storage based on the patented SCCV technology. The cost advantage of Big-Ton H_2 allows it to be "oversized" for two important benefits.

First, oversizing the storage subsystem offers the opportunity to significantly reduce the capacity and cost of electrolyzer by spreading H_2 production over a much longer period of time when the peak electricity generation unit (LM6000 in this case) is not running at its longest hours. The peaker's operation varies greatly especially between weeks even months, there are many days when the peaker runs only a few hours or not run at all for a day. It is also important to note that the fuel cost or electricity cost to make H2 also fluctuates significantly over days or weeks. By oversizing the low-cost Big-Ton storage system, it is possible to run the electrolyzer when the fuel cost is most favorable.

The second benefit from oversizing the storage subsystem is to shift the hydrogen production and usage over weeks to months – such as using the H_2 produced in May/June to meet the peak demand in July and August – to achieve the overall system cost minimum.

A holistic system level TEA modeling tool specific to HyPeaker was developed in this project for the purpose to optimize the HyPeaker system design for total cost reduction and at the same time to ensure its performance meeting the operation requirement of utility owner (TVA in this case). Our HyPeaker TEA modeling tool performs high-fidelity system level design and cost optimization analysis to determine the requirements of the hydrogen storage subsystem and the hydrogen production (alkaline electrolyzer) for total system cost optimization, based on two sets of input data streams: (i) the projected hourly operation profile over a period of 10 years provided by TVA, and (ii) unit cost of major subsystem and components such as storage vessels, compressors, and electrolyzers provided by manufacturers and suppliers. It specifically excludes the cost of LM6000 aeroderivative gas turbines as they are already available and being used for electricity generation at the Johnsonville site. The modeling tool is capable of including seasonal balance of H_2 production and usage (long duration storage scenario) for optimization.

The optimization modeling tool is developed based on the following principles.

- Run "smaller" electrolyzer for longer hours over week/month shift, when fuel/electricity cost is low and electricity generation unit is not running.

- Use “oversized” storage vessel to store H2 over week/month
- Ensure enough H_2 for peak day usage
- Use hourly electricity/fuel cost variations (daily and seasonal) as input
- Use hourly electricity generation operation profile as input
- Use unit cost of major components as input
- Optimization target: total system cost minimum and lowest possible LCOE-a.
- Output: capacity or sizes of major components.

Figure 14 provide an example of modeling analysis results. This is a case of “average duty year” operation scenario. The top plot is the simplified version of the project hourly electricity power generation output in an “average year” from an LM6000 unit. The capacity factor in this case is 6.45% over the period of 1 year. The bottom plot illustrates the amount of H_2 stored in the system. Hydrogen produced in the lighter duty months/weeks (such as in May and June) is used to meet the heavy use during July and August. In this case, the HyPeaker is optimized to cover 100% of operation hours. The capacity of alkaline electrolyzer is reduced to 10MW, with a corresponding reduction of compressor size to 180 kg-H_2/hr. The Big-Ton storage vessel is oversized to store 8,910 kg-H_2. Using the same unit price of major components in the baseline case, the total cost of the system reduces to \$10.175M. The added LCOE (LCOE-a) is reduced to \$243/MWh, using the same 30-year 3% interest rate of debt. The costs of major components are in Table 3.

In the above system level optimization, the cost advantage of our SCCV technology made it possible to “oversize” the H2 storage subsystem to achieve major overall system capital cost reduction. More specifically, the capacity of SCCV storage subsystem is increased to store 11,000 kg of H_2. This is about 3 times more than the baseline capacity of 4,000kg H_2 required to supply H_2 for the longest 14-hour continuous operation of the HyPeaker in the summertime. A closer look of Figure 14 about the hydrogen production and storage profile over an one-year period of operation revealed that the oversized SCCV storage subsystem design enabled long-duration H_2 storage, which is essential to balance the hydrogen production and usage shift over weeks to months (such as using the H_2 produced in May/June to meet the peak demand in July and August) to achieve the overall system cost minimum.

Our TEA model also showed that the use of today’s high-cost steel tube based H_2 storage system (at \$1500/kg-H_2) would be too expensive for long duration storage to balance the off-peak H_2 production and peak-time hydrogen usage. In fact, the storage capacity should be less than a day for minimum total system cost. This in turn required much larger electrolyzer to produce sufficient hydrogen in 10 hours to meet the demand of peak hydrogen use of 14 hours in the same day. The total capital cost of such system would be \$18.3M, compared to the \$10.175M capital cost enabled by the cost-effective SCCV technology.

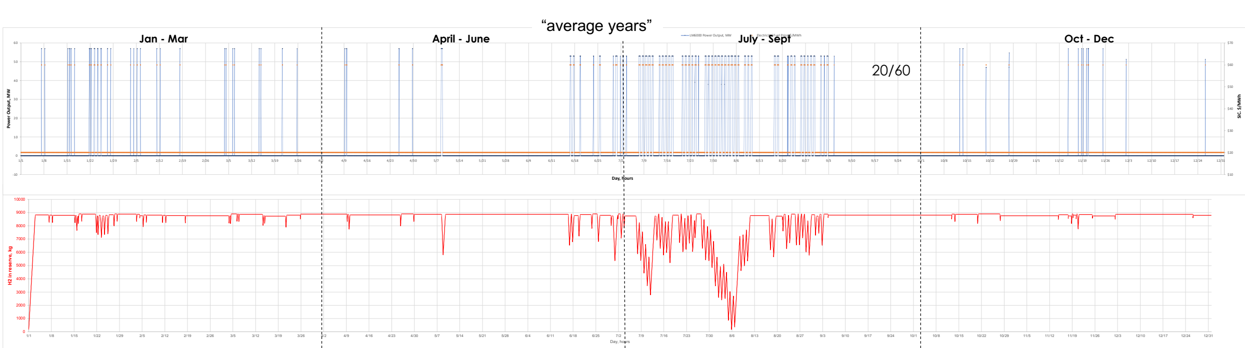

Figure 14 HyPeaker operation profile for an “average usage year”.

Table 3 Cost of major components of HyPeaker optimized for a simplified average duty year operation scenario (6.45% CF) in Figure 14.

	Type	Capacity	Unit Cost	Cost	% total cost
Electricity production	LM6000	57.7MW	N/A	Not included	
H_2 storage	Big-Ton	8910kg	\$500/kg-H_2	\$4,455,000	43.8%
Compressor	Diaphragm compressor	180kg-H_2/hr	\$4000/kg-H_2/hr	\$720,000	7.2%
H_2 production	Alkaline Electrolyzer	10MW	\$500/kW	\$5,000,000	49.0%
Sub Total				**\$10,175,000**	

The HyPeaker design optimization tool was then applied to analyze the entire 10 years of projected hourly operation profile of power generation unit to determine the optimum system design. The Johnsonville site-specific HyPeaker system design optimized for total capital cost and LCOE for the 20 years design life is:

- **Electrolyzer: 9MW**
- **Storage vessel: 11,000kg H_2**
- **Compressor: 160kg-H_2/hr**
- **Total capital cost: \$10.68M.**

This design is capable of supplying H_2 to cover 100% project operation scenarios. The total cost of major component (excluding LM6000) is \$10.68M, which is slightly higher than the simplified average duty year operation scenario above. The reason is that this 10-year operation includes a wide spectrum of capacity factor variations from year to year, from 1.5 – 12%. This design covers the heavy-duty years for up to 12% capacity factor. The size of the storage vessel increases to 11,000 kg-H_2, required for the heavy-duty years. There is a reduction of electrolyzer capacity to 9MW, and corresponding reduction of compressor throughput rate to 160kg-H_2/hr.

The HyPeaker design optimization tool was also used to gain insight of system cost variations as function of different electrolyzer and storage combinations. Figure 15 summarize the findings of different electricity generation duty years. It is noted that in all cases, H_2 is available for 100% of the time. Clearly, there is an optimal range of electrolyzer and storage size combination for minimum total system cost when the annual CF of electricity power generation unit is above 5%. For light duty units (CF=1-2%), it is advantages to have smaller electrolyzer and proportionally increase the size of storage system. For the case of Johnsonville site, the CF varies considerably in 20-years operation lifetime. The HyPeaker design must cover all different scenarios.

Figure 15 also reveals that the added leveraged cost of electricity produced by the HyPeaker (LCOE-a) is not only highly depended on capital cost of the system, but also the capacity factor. For the site-specific optimal design at the Johnsonville site, the LCOE-a increases from \$300/MWh at 10-12% CF, to \$450/MWh at 5-6% CF, to over \$1000/MWh at 1-2% CF. Furthermore, the utilization rate of electrolyzer is tightly associated with the CF, as summarized in Table 4. Even in the case of heavy-duty years (10-12% CF), the utilization rate of electrolyzer is only in the range of 20%. This means, even after 30 years of operation, the electrolyzer still have about 57% of remaining life (for a typical alkaline electrolyzer service lifetime of 90,0000 hrs).

While it is common that the cost of electricity generation of a peaker unit is highly dependent on its capacity factor, and is much higher than the baseload power generation units, the relatively low utilization rate of electrolyzer offers further opportunities to optimize the design and use of HyPeaker to further reduce the LCOE and improve its economic benefits. This is the subject of further design optimization described in the next sub-section (Section 5.5).

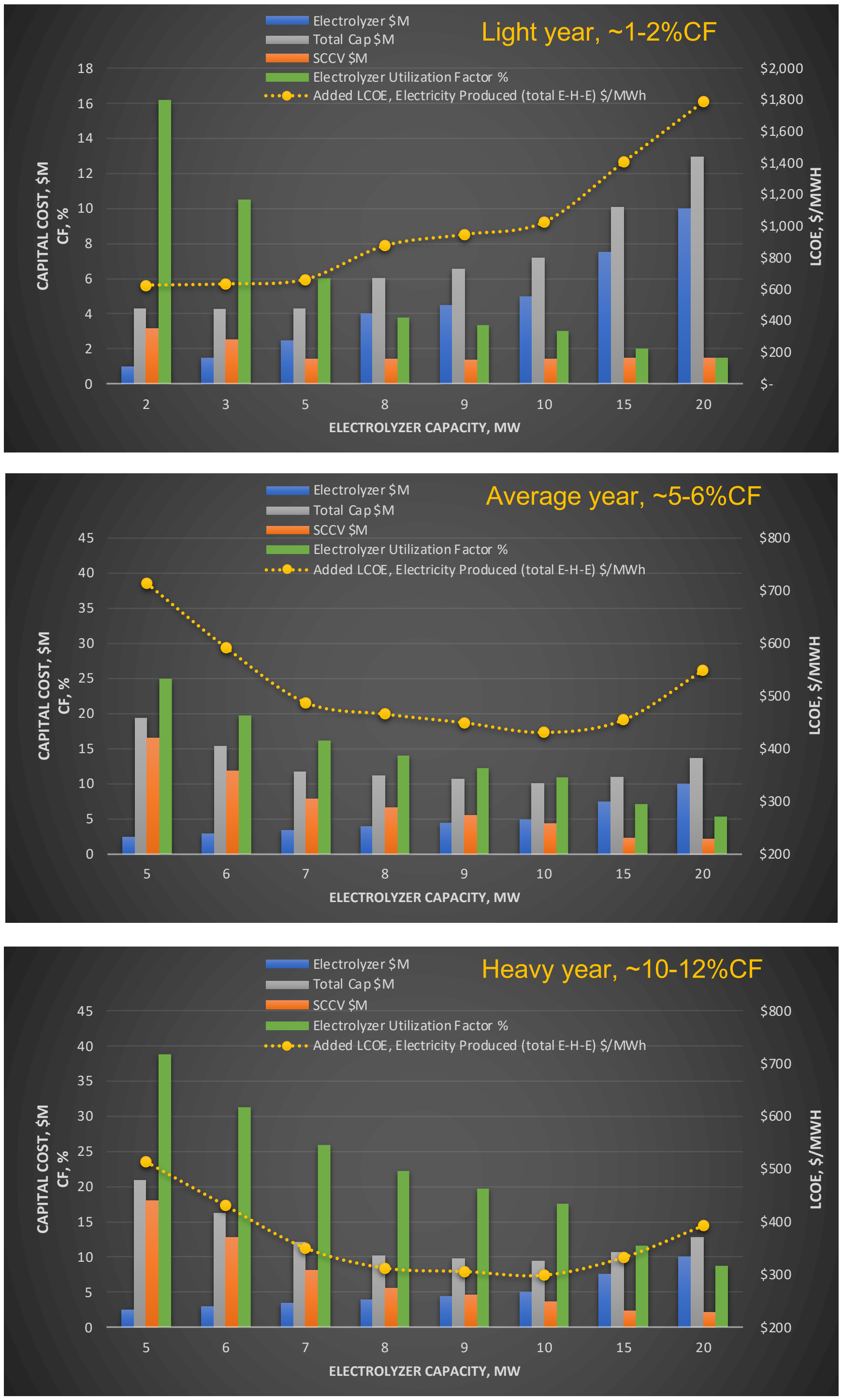

Figure 15 Cost, electrolyzer utilization factor, and LCOE-a as function of electrolyzer size for different power generation CF scenarios. LCOE-a assumes 7% discount rate for 30 years.

In addition, another opportunity is to supply the hydrogen produced by HyPeaker for other purposes. As shown Table 4, the cost of hydrogen produced by HyPeaker can be as low as \$3.93/kg-H_2, at 20% utilization rate of electrolyzer and 7% of interest rate. It is expected that the cost would be even lower by increasing the utilization rate, potentially reaching \$1.5/kg-H_2. It should be noted that this aspect is not fully investigated in this project.

Table 4 LCOE-a, Electrolyzer utilization rate, and LCOH as function of CF. LCOE-a and LCOH assume 7% discount rate for 30 years.

	LM6000 CF, %	**LCOE-a, Electricity (Total E-H2-E) \$/MWh**	**Electrolyzer Utilization Rate, %**	**LCOH (Total E-H_2), \$/kg-H_2**
Heavy Years	10-12%	\$306	20%	\$3.93
Average years	5-6%	\$449	12.3%	\$5.76
Light Years	1-2%	\$946	3.3%	\$12.12

5.5 HyPeaker System Optimization for 90% Availability

Level II optimization study described in Section 5.4 revealed two opportunities to improve the HyPeaker system design.

First, due to the low round trip efficiency of the HyPeaker system, the use of HyPeaker when natural gas is used to produce the electricity in the first place would actually **increase** the CO_2 emission. Indeed, any practical energy storage system would increase the CO_2 emission when the electricity is generated from natural gas or fossil fuels. Therefore, a more sensible solution would be to use the excessive or curtailed electricity from CO_2 emission free sources such as solar farms, wind farms or nuclear power plants, to produce hydrogen, and integrate them with the HyPeakers. We reviewed different potential options to use CO_2 emission free electricity for H_2 production that would be applicable to the Johnsonville site. Among the three clean electricity generation options (solar, wind and nuclear), the nuclear option is deemed best fit with TVA's current electricity generation capacity portfolio. So the electricity generated by nuclear power plant was used in this round of system optimization analysis. It turned out that, the nuclear electricity production is better fitted for our goal of reducing the electrolyzer capacity, because, unlike the solar and wind options in which the electricity generation is intermittent in nature, the nuclear power plant operates in a rather stable matter, so it is possible to generate hydrogen continuously which in turn greatly reduces the electrolyzer capacity requirement and the cost of the electrolyzer sub-system. Furthermore, it turned out that the stable hydrogen production is better fitted for the alkaline electrolyzer which is currently the most competitive technologies for hydrogen production via electrolysis.

Second, it is to improve the utilization rate of the electrolyzer. As shown in Figure 14, the low utilization rate is due to the fact that the capacity of the electrolyzer is dedicated by the peak demands only during a few days in the summertime (between end of July and first week of August). A smaller electrolyzer would not be able to fully cover the demand for H_2 in these few days. This leads to the concept of 90% availability design, made possible by the fuel flexibility of gas turbines for electricity generation.

The aeroderivative gas turbine (LM6000) at the Johnsonville site allows the use of either H_2/natural gas mix (up to 20% vol for now) or 100% natural gas. Therefore, in the case of high peak demand period during which hydrogen is used up, it is possible to run the gas turbine with 100% natural gas. (The electronic controlled ignition system of the aeroderivative gas-turbine could be readily adjusted to switch the fuel back and forth). This means that, it is possible to design a HyPeaker that does not need to cover 100% of the operation life with H_2. Instead, it can be designed such that H_2 just needs to be available for 80-95% of operational hours. The remaining operations can use 100% natural gas, by taking advantage of fuel flexibility of LM6000. This in turn would reduce the capital cost of the HyPeaker. (We also note that it is almost impossible to design a system that cover 100% of unexpected, unless that the system is so over designed with very high cost). This design is terms as **90% availability design**.

We applied our HyPeaker design optimization tool to investigate the 90% availability design concept, by analyzing and optimizing various scenarios to increase the electrolyzer utilization rate for overall system and operational cost reduction. The result was a 66% reduction of the HyPeaker system, as shown below.

- Electrolyzer: 3MW (vs 9MW previously)
- Storage vessel: 11,000kg H_2 (same as before)
- Compressor: 55kg-H_2/hr (vs 160kg-H2/hr previously)
- **Total capital cost: $7.1M vs $10.68M of optimized design for 100% availability.**

It is noted that with the above system design and specifications, it is possible to run the HyPeaker system to provide sufficient hydrogen to meet 92.6% of operation days. Only in about 27 days of a year there is a shortage of H2 supply to the aeroderivative gas turbine. This meets the requirement set forth by TVA of probability to meet 80-90% operation needs.

We also benchmarked the cost of HyPeaker system with Li-ion battery based energy storage system for the same TVA peaker plant operation. On the basis of 80% round trip efficiency, $200/kWh cost, 14 hours of operation to produce 50.65MWh electricity (from 20% vol H_2), and 30 years operation, the capital cost of Li-Ion battery system would be $38M, which is more than 5 times of our HyPeaker system.

5.6 Technology Gap Assessment

The HyPeaker utilizes the excessive electricity generated from clean electricity sources such as from a nuclear power plant or from wind/solar sources to produce hydrogen which in turn generates electricity for the peak demands. The capacity and operation profile of HyPeaker have been optimized to satisfy the wide range of peak demand scenarios of peaking power Figure 14 projected by our utility team member TVA. TVA for 20 years –from daily peaking operation to meet the seasonal (12 months or longer) imbalance of supply and demand in electricity. Supporting such wide range of duration scenarios would be prohibitively expensive for Li-ion based battery energy systems. In this project, the HyPeaker system has been designed and optimized for a site-specific application – TVA's Johnsonville GT Plant.

The HyPeaker has three major sub-systems:

- Hydrogen production sub-system. Various types of electrolyzers are available to produce H_2 from electricity. After analyzing TVA's specific clean electricity generation portfolio, it was determined that the excessive electricity from its nuclear power plants would be the best choice for the HyPeaker (the details of such consideration were given in previous progress reports). Alkaline electrolyzer was selected because of the relatively stable electricity generation profile from a nuclear power plant. For our application, alkaline electrolyzer is advantageous over other technologies, as it is the most mature and cost-effective technology to produce H_2 via electrolysis. It is also choice of technology for MW to GW level high throughput H_2 production. For the TVA site-specific application, we carried out a multi-round system design optimization to significantly reduce the capacity of alkaline electrolyzer from a reference of 10-12MW (TVA baseline design) to 3 MW using our proprietary TEA analysis tool for HyPeaker. This greatly reduced the capital cost of the electrolyzer sub-system for HyPeaker. Such substantial capacity (and cost) reduction of electrolyzer was made possible by (1) oversizing the cost effective SCCV storage sub-system, and (2) optimizing the hydrogen production operation from the relatively stable electricity of nuclear power plant.
- Hydrogen storage sub-system including the high-pressure hydrogen storage vessels and hydrogen compressors. We optimized the hydrogen storage vessel by taking advantage of our low cost SCCV

technology to achieve lowest overall capex of the entire HyPeaker system. In addition, high-throughput hydrogen compressor, in the range of 50 – 300 kg-H_2/hr for our site-specific application, is required to raise the H_2 pressure from 150psi (typical alkaline electrolyzer outlet pressure) to 3000 psi (storage pressure). The most suitable compressor technology currently available on the market for such capacity requirement is the diaphragm type of compressors.

- Electricity generation from hydrogen sub-system. Among a variety of technologies and systems to generate electricity from hydrogen, we selected the aeroderivative gas turbine for the HyPeaker. The selection is a natural fit to fossil fuel-based power plants based on the following major considerations: (1) the aeroderivative gas turbines and similar types are a mature technology and already widely used or considered for natural gas fueled peakers by many US utility owners. TVA has already invested in such type of gas turbines to serve the peak electricity demands; (2) they can adopt the use of mixed H_2/Natural Gas fuel for flexibility. Up to 20% of hydrogen can be added to natural gas with minor or no modification of the system. (3) MW level electricity generation capacity (60MW capacity for the TVA site-specific system) that are difficult or very expensive to meet with today's PEM or other fuel-cell based technologies.

Through this project in the development of the HyPeaker system for fossil fueled power plants, we were able to identify and select relevant equipment manufactures/suppliers for all the major components of the HyPeaker. We obtained multiple quotes and detailed technical specifications for the above sub-systems from different vendors and manufacturers. Such information allowed us to design and optimize the HyPeaker for total cost including both the capital cost and operational cost while meeting the capacity and operation requirements by TVA's peaking power generation unit at the Johnsonville site. We also reviewed and surveyed extensively the relevant technologies including their readiness for the proposed HyPeaker applications. Through these efforts, we concluded that **the HyPeaker can be designed, manufactured, installed and integrated with the fossil power plants, with sub-systems and components commercially available on the market today.** Therefore, there is no major technology gap for HyPeaker, even when it is scaled up an order of magnitude larger than the site-specific HyPeaker system at TVA Johnsonville GT plant. In other words, the HyPeaker can be designed, engineered, and installed today, as a technologically viable solution to cover a wide range of energy storage duration needs, from daily peaking operation to seasonal shifting for fossil fueled assets.

Technology aside, our study also revealed two other major factors that would potentially hinder the widespread adoption of hundreds of MWh to GWh level hydrogen energy storage solutions such as the HyPeaker for fossil power plants and other applications. They are (1) the high cost and (2) limited capability of domestic manufacturers for both electrolyzers and high-pressure hydrogen storage vessels at the capacity level (350-500 MWh) required for HyPeaker.

For alkaline electrolyzers, the quotes and specifications from domestic manufacturers would be about 3 times most expensive than non-domestic manufacturers. And the lead time of domestic manufacturers are much longer due to their limited manufacturing and assembly capability. For example, one of the domestic manufacturers quoted at ~$1000/kW and was unable to provide a delivery time, whereas a non-domestic manufacturer quoted at ~$300/kW with a delivery time within 12 to 18 months. Our experience is consistent with the published survey results – Figure 16 shows one such survey result. The high capex cost of electrolyzer is a predominate factor affecting the cost of H_2 production from clean renewable electricity sources, as illustrated in Figure 17. It should be noted that the sources of electricity and use case scenario in Figure 17 is not the same for the HyPeaker in this project. In addition, it does not include the hydrogen storage and electricity generation from hydrogen. Nevertheless, it shows the importance of capex cost of electrolyzer on the economics of the HyPeaker.

The hydrogen storage vessel sub-system had the similar situation. Quotes from US manufacturers are 5-6 times more expensive than globally sourced manufacturers, for the capacity and pressure of HyPeaker (1-2 tons per vessel at 3000 psi).

Our utility partner of this project, TVA, views the high capital cost of HyPeaker from domestic sources is *the barrier* to introduce HyPeaker in their operation, despite of the fact that the LCOE of HyPeaker is only 50% of the Li-ion battery system for the same projected 20-year peaking unit operation profile by TVA. (HyPeaker's relatively low round trip efficiency (~23%) is included in its LCOE, as detailed in previous project reports). TVA's concerns are shared with other potential utility operators we have interacted with.

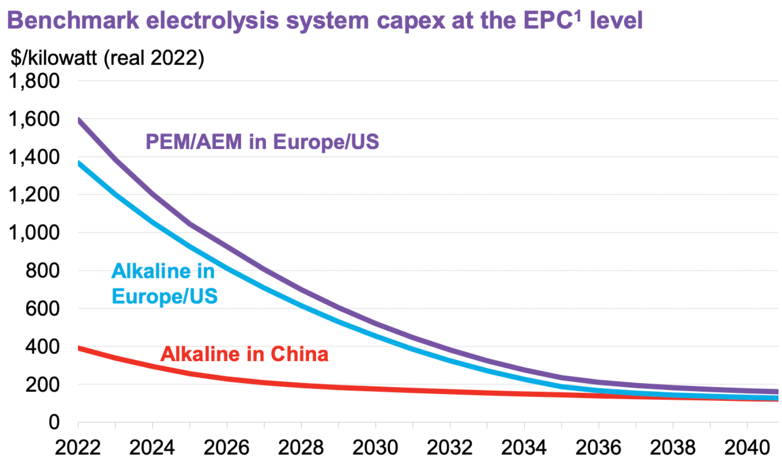

Figure 16 Benchmark electrolysis system capex at the EPC level (source: Adithya Bhashyam, BNEF Hydrogen Outlook, Bloomberg NEF, 2023).

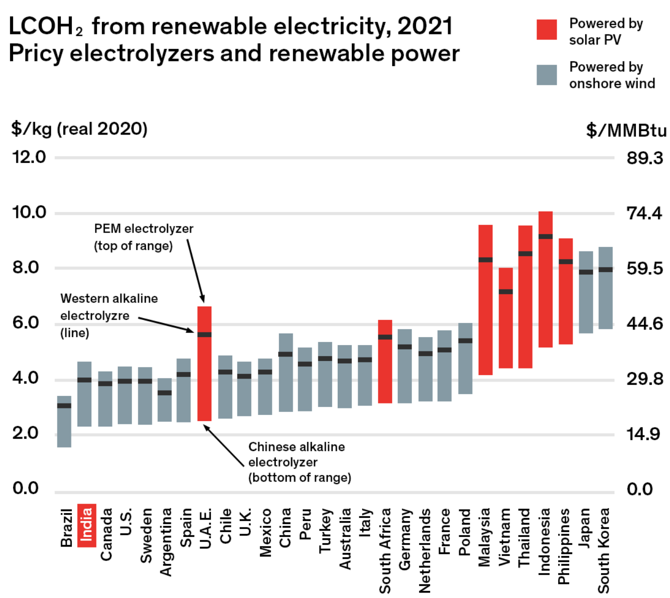

Figure 17 Levelized cost of H2 from renewable electricity. Bloomberg NEF 2021)

It is important to note that alkaline electrolyzers and high-pressure hydrogen storage vessels are relatively mature technologies. Furthermore, manufacturing processes to build them are commercially available and materials used are abundant with no major geopolitical constraints. The higher costs of domestically manufacturing them are mainly related to today's limited manufacturing capability and supply chain infrastructure. Therefore, financial or economic incentives would be imperative to overcome quandary of *high cost in the early stage of the adoption*, allowing the economics of scale kicking in to lower the equipment cost over time once the markets for hydrogen energy reaches a critical level.

Our TEA analysis suggested that the HyPeaker would become economically viable, under the following condition:

- The price of electrolyzers from domestic manufacturers would be at the same level ($300/kW) of today's globally sourced manufacturers. (The projected cost of US manufactured electrolyzers would be below $200/kW in ten years – Figure 16);
- The Big-Ton vessel is to be assembled in the US with global supply of raw materials or semi-products (steel plates or cylinders). This would lower the cost of SCCV to $250/kg-$H_2$ stored;
- The interest of financial loans for the HyPeaker is lowered to 3%, from the customary 5-7% for 30 years.

Reaching the above electrolyzer and hydrogen storage cost targets is considered to be realistic, with the financial and economic incentives in the bipartisan Infrastructure Investment and Jobs Act. With these "near term" incentive, the capex of the HyPeaker system for the TVA Johnsonville Plant (3MW alkaline electrolyzer, 10000 kg-H_2 storage system, 55 kg-H_2/hr compressor, 6.86% average HyPeaker capacity factor) would be reduced to ~$3.6M from ~$7.1M, and the LCOE-a is lowered to ~$85/MWh. **Since the peaking units generally operate at peak usage period, thereby demanding higher price, the projected $85/MWh LCOE-a would be within the realm of financial viability for TVA and other utility operators.**

5.7 Environmental Information

We worked with TVA to review and evaluate the potential for adverse environmental, ecological, culture and socioeconomic impacts from the proposed HyPeaker system at TVA's Johnsonville GT Plant site. The evaluation was based on the identified likely locations within the plant for installation of the electrolyzer sub-system, the hydrogen storage sub-system, and the connections to feed H_2 to the gas turbine for electricity generation. It is concluded that the potential environmental adverse impacts of HyPeaker would be minimal at the existing GT plant. It would not affect the operation of the plant.

First, the HyPeaker system would not generate any liquid wastes (other than circulated water), emission of greenhouse gases, nor any solid wastes during the normal operation of the HyPeaker. Materials for construction of the HyPeaker system (steels, concretes, and small presentation of plastics) are common to many other equipment already inside the plant, and would not pose additional impact to the existing plant.

Alkaline water electrolysis is based on an alkaline electrolyte, potassium hydroxide (KOH). KOH is added to the water, typically in 30 wt.%. Although corrosive in nature, KOH is confined inside the reactor vessel and recycled during regular operation. The proposed installation of the electrolyzer system will include additional confinement to prevent the accidental leak to environment.

The safety of high-pressure hydrogen storage vessels was also evaluated. It is concluded that, as the SCCV is designed and manufactured following the code/standard, and installed following the safety regulations and requirements, the environmental impact of such system would be well managed on an open space at the plant site. The industry has extensive experience in handling such systems. These industry practices will be followed during the operation of the vessel.

5.8 Commercialization Plan

We have identified a specific scenario suitable for early adoption of hydrogen energy storage technology in fossil power generation plants, based on both technological and economic considerations. The specific market sector target is the peaking power generation plant. The hydrogen peaking power generation units (HyPeaker) integrates the hydrogen production from electricity, hydrogen storage, and electricity generation from hydrogen as a standalone system to generate electricity from hydrogen (produced from clean and renewable sources) to meet the peak demands. The learnings from this first market entry point (HyPeaker) would help further advance the technology and gain market confidence and acceptance to add larger synergistically integrated *hydrogen* energy storage system (SIHES) to baseline power plants at hundreds of MW to GW level.

The selection of HyPeaker as the first targeted early adoption is based on the following considerations.

- Today's natural gas and oil peakers are generally more expensive and inefficient to run, on MWh basis, than the baseload plants. The also emit higher rates of CO_2 and health-harming air pollutants. Therefore, there are considerable economic and environmental incentives to replace them and/or supplement with clean power storage and generation technologies such as SIHES.
- Today's peaker plants are also typically **disproportionately located in disadvantaged communities**, such as urban centers and in low-income and minority communities, where vulnerable populations already experience high levels of health and environmental burdens. **There would be significant societal benefits to replace oil and gas-fired peakers power plants with clean ones**.
- Compared to baseload power plants, the sizes or capacities of the peakers are much smaller. In the case of MGS, the peaker Mystic Jet is rated at 9MW, compared to the baseload Mystic 8 that is rated at 700MW. As such, challenges to scale up the SIHES, from both technical and capital investment perspective, are much more manageable with the HyPeaker units.
- The operational and grid characteristics of peakers lend them as a prime candidate for hydrogen system such as HyPeaker. Today's peaking power plants run infrequently and are brought online to help deliver electricity during periods of high peak demand. Typically, they are only used for a few hours at a time, typically running less than 10-15% of the time (capacity factor). The Majestic Jet unit has a much lower capacity factor, in the range of 1-3%. Such low-capacity factor and intermittent operation offers the flexibility for optimal HyPeaker design in energy arbitration: with low cost and oversized SCCV, it is possible to selectively generate H_2 when the electricity price is low or even negative, and supply the electricity during the short peak demand period at prime price.
- United States currently have more than 1,000 natural gas- and oil-fired peaker plants across the country to meet infrequent peaks in electricity demand. This represents a sizable potential market for the deployment of hydrogen based energy storage system in next 5-10 years.

Together, HyPeakers provide a unique opportunity to strategically displace some of the most polluting electricity power generation units on the grid, to yield the greatest health, environment, and equity co-benefits.

6 SUMMARY

This report was prepared as an account of work sponsored by the Office of Fossil Energy and Carbon Management of U.S. Department of Energy. The work aimed to explore and advance an innovative hydrogen energy storage system – the synergistically integrated hydrogen energy storage system (SIHES) – that has the following characteristics:

- Compatible with existing or new coal and gas fuel electricity generation units,
- best suited for intermediate to long duration energy storage, from 12 hours to weeks even months, and
- capable of storing energy at the utility scale – hundreds of MWh to GWh energy storage with power output level in tens to hundreds of MW.

The work was a "Conceptual Design Study for Engineering Scale Prototypes of Hydrogen Energy Storage Integrated with a *Site-Specific* Fossil Asset", in two phases. Phase I was a site-specific concept feasibility study in partnership with Exelon Corporation and Tennessee Valley Authority (TVA). Upon reviewing and analyzing the suggested fossil power plant sites, their operation histories, and electricity market price (LMP) fluctuations over days (short term) and weeks to months (long-duration), we identified the most likely scenario and strategy for early adoption of SIHES for fossil plants, that is, to use SIHES as peaking power generation units (so named as **HyPeaker**) as the first market entry point. The learnings from such early adoption would help further advance the technology and gain market confidence and acceptance to add larger SIHES to baseload power plants at hundreds MW to GW level.

The selection of peaking power generation unit (peaker) as the first targeted early adoption is based on the following considerations.

- Today's natural gas and oil peakers are generally more expensive and inefficient to run, on MWh basis, than the baseload plants. They also emit higher rates of CO_2 and health-harming air pollutants. Therefore, there are considerable economic and environmental incentives to replace them and/or supplement with clean power storage and generation technologies such as SIHES.
- Today's peaker plants are typically disproportionately located in disadvantaged communities, such as urban centers and in low-income and minority communities, where vulnerable populations already experience high levels of health and environmental burdens. There would be significant societal benefits to replace oil and gas-fired peaker power plants with clean ones.
- Compared to baseload power plants, the sizes or capacities of the peakers are much smaller. As such, challenges to design and construct the first HyPeaker unit, from both technical and capital investment perspective, are much more manageable.
- The operational and grid characteristics of peakers lend them to a prime candidate for hydrogen system such as HyPeaker. Peakers run infrequently and are brought online to help deliver electricity during periods of high peak demand. They are only used for a few hours at a time, typically running less than 10-15% of the time (capacity factor), often as low as 1-3%. Such low-capacity factor and intermittent operation offers the flexibility for optimal HyPeaker design. By oversizing our unique low-cost high-pressure hydrogen storage vessels, it is possible to significantly reduce the capital and operational costs of HyPeaker system.
- United States currently have more than 1,000 natural gas- and oil-fired peaker plants across the country. This represents a sizable potential market for the deployment of hydrogen-based energy storage system in next 5-10 years.

In Phase II, preliminary front-end engineering design (Pre-FEED) studies was carried out to further develop and refine a site-specific HyPeaker, to demonstrate both the technical feasibility and the economic viability to integrate the HyPeaker "within the fence" of a fossil power plant. This specific site was TVA's Johnsonville Combustion Turbine Plant. The HyPeaker was designed and engineered to integrate with a

60MW aeroderivative gas turbine unit already available at TVA's Johnsonville site with the following primary requirements:

- Hydrogen supply to power one aeroderivative gas turbine unit rated power level at 60MW.
  - 20% H_2-80% natural gas mix (volume percentage) for normal operation.
  - Inlet pressure to gas turbine: 800psi.
  - Availability for at least 90% of electricity generation time. The remaining 10% can be covered by 100% natural gas taking advantage of the fuel flexibility of aeroderivative gas turbines.
- Projected site-specific operation profile over next 10 years, provided by TVA.
- Technology maturity, capacity, market availability and cost of all major sub-systems and components, primarily according to equipment OEM's budgetary quotes and specifications supplemented by extensive surveys.

The HyPeaker consists of three major sub-systems:

- A hydrogen production sub-system (E-H_2). It uses the excessive electricity from clean sources to produce hydrogen. Alkaline electrolyzer was selected, based on the consideration of its technology maturity, capacity and cost over other electrolyzers available on the markets at multi-MW level, as well as its compatibility with the projected hydrogen production operation profile of HyPeaker.
- A hydrogen storage sub-system. Hydrogen produced from the E-H_2 sub-system is stored over the period of hours to weeks even months at 3000 psi before it is used for electricity generation later. High-pressure gaseous hydrogen vessel was selected as it is the most cost-effective and mature hydrogen storage technologies on the market, for the amount (in tens to hundreds of tons) and duration (weeks to months without lost) of hydrogen stored. In particular, our Big-Ton storage vessel, which was based on the innovative steel-concrete composite vessel (SCCV) was chosen due to its low cost and domestic manufacturing availability. Indeed, the Big-Ton turned out to be the primary reason leading to significant cost advantage of the HyPeaker over other hydrogen storage systems and Li-ion battery energy storage systems for intermediate and long-duration applications. In addition, diaphragm type hydrogen compressor was selected to pump hydrogen from 150 psi (typical outlet pressure of the electrolyzer) to 3000 psi (the storage pressure) to meet the high through-put rate (200-300kg-H_2/hr) of HyPeaker.
- An electricity generation sub-system (H_2-E). The HyPeaker utilizes the 60MW aeroderivative gas turbine unit that existed already at the Johnsonville site for this purpose. This has two major advantages unique to fossil power plants – it not only avoids the additional capital cost for a different H_2-E sub-system but also offers the flexibility of mixing H_2 and natural gas which has many benefits in the early transition phase of hydrogen energy storage systems in long-duration applications.

The design and engineering of the Johnsonville site-specific HyPeaker was then optimized using a techno-economic analysis (TEA) modeling tool developed by WE New Energy. The optimization was subjected to the following criteria:

- Meet the capacity and operational requirements of electricity generation unit over wide range of peak demand scenarios from daily peaking operation to seasonal (12 months or longer) imbalance of supply and demand in electricity over 20 years projection.
- Minimize the total CapEx of the HyPeaker system and the leveraged cost of electricity production from the HyPeaker for the projected 20 years, using the equipment cost and specifications obtained from both domestic and global equipment suppliers.
- Minimize the overall CO_2 emission of the HyPeaker relative to the baseline natural gas peaking unit.

The optimal design and specification of the Johnsonville site-specific HyPeaker are the following:

- Alkaline electrolyzer: 3MW

- Big-Ton storage vessel: 11,000kg H_2 at 3000psi.
- 4-stage diaphragm hydrogen compressor: 55kg-H2/hr from 150psi to 3000psi.

The HyPeaker is designed to have the capability of providing sufficient hydrogen for greater than 90% availability. All major components have design life of 30 years.

The capex of HyPeaker is estimated at **$7.1M**. This included $1.5M for the electrolyzer, $5.6M for the storage vessel and compressor. Since the aeroderivative gas turbine unit was already available at the Johnsonville site, its cost was not included. Cost of other minor components/parts and installation cost were not considered in the Pre-FEED study.

Other key findings from this work include the following:

- HyPeaker can be designed, manufactured, installed and integrated with the fossil power plants, with sub-systems and components commercially available on the market today, even when it is scaled up to an order of magnitude larger than the one at the Johnsonville site. HyPeaker is a technologically viable solution to cover a wide range of energy storage duration needs, from daily peaking operation to seasonal shifting for fossil fueled assets.
- The cost advantage of SCCV based Big-Ton H_2 storage vessel made it possible to "oversize" the H_2 storage subsystem to achieve overall system level cost optimization. The benefits are two-fold. First, it allows to significantly reduce the capacity and cost of electrolyzer by spreading H_2 production over a much longer period of time when the fuel cost for electricity production is low. Second, it allows to balance the hydrogen production and usage shift over weeks to months (such as using the H_2 produced in May/June to meet the peak demand in July and August), to achieve the overall system cost minimum. As such, the capital cost of HyPeaker system using the Big-Ton was less than half of the cost of a system with today's steel tube based H_2 storage system. The HyPeaker has even better cost advantage Li-ion battery based energy storage system. The estimated capital cost of Li-Ion battery system would be at $38M, under the same projected 20-year electricity generation profile of the Johnsonville site. This is over 5 times more expensive than the HyPeaker system.
- Since industry scale energy storage systems do not have 100% energy conversion and storage efficiency, energy storage systems using fossil fuel generated electricity would *increase* the CO_2 emission. This is particularly the case for HyPeaker due to its low round trip efficiency. Therefore, a more sensible solution would be to the excessive or curtailed electricity from CO_2 emission free sources such as solar farms, wind farms or nuclear power plants, to produce hydrogen, and integrate them with the HyPeaker. Electricity from TVA's nuclear power plants was used for the Johnsonville HyPeaker.
- The economic viability of HyPeaker is expected to be further improved when global supply chains are taken into consideration. For the same Johnsonville site specific HyPeaker, the capex would be reduced to ~$3.6M from ~$7.1M, and the LCOE is reduced to ~$85/MWh. With the financial and economic incentives in the bipartisan Infrastructure Investment and Jobs Act, the cost of domestically produced HyPeaker sub-systems would be at the level of today's global suppliers within 3-5 years. Since the peaking units generally operate at peak usage period, thereby demanding higher price, the projected $85/MWh LCOE would be within the realm of financial viability for TVA and other utility operators.

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APPENDIX: TECHNOECONOMIC STUDY OF GENERIC IMPLEMENTATION OF HYPEAKER

This section presents a more generic technoeconomic study of the HyPeaker beyond the Johnsonville site, to provide the insights of HyPearker in a broader sense. Assumptions and market data used in the study are not restricted to the Johnsonville site, although still within the scope of integration of hydrogen energy storage technologies with fossil fueled power generation peaker plants. The study was performed by West Virginia University with support from WE New Energy Inc as part of this project.

1.0 Introduction

There are considerable efforts worldwide for reducing the use of fossil fuel for energy production1.[1] While renewable energy sources are being increasingly used, fossil fuel still contribute about 80% of the energy used worldwide.[2] As a result, the level of CO_2 is still increasing fast in the atmosphere currently exceeding about 410 ppm.[3] For reducing CO_2 build up in the atmosphere, various approaches are being investigated. For the electric power generation sector, two key approaches are post-combustion CO_2 capture and use of H_2 as a fuel for power generation.

The utilization of hydrogen as a fuel in power plants that can reduce CO_2 emission by over 30-40%.[4] Hydrogen can be used as an energy storage medium producing it during the time of low demand and abundant availability of renewable-based power while utilizing it later when demand is high and/or availability of renewable-based power is not sufficient to satisfy the demand. Fossil fuels are still the major sources of hydrogen globally today with only a very low amount of Hydrogen being produced globally from water electrolysis.[5] Alkaline electrolyzers, proton exchange membrane (PEM) electrolyzers and solid oxide electrolyzers are the three known types of water electrolyzers. Among these three options, alkaline electrolyzer is the best option in terms of capital cost, and operating conditions.[6] Also, alkaline electrolyzers are well known for their long-term stability, and cost effectiveness.[7]

Hydrogen can be stored in different ways- as a liquid under cryogenic condition, as a pressurized gas, and in the form of solid or liquid hydrides.[8] Out of these, storing of compressed gas is currently the cheapest and most practical option especially for distributed storage. However, capacity and maximum operating pressure of storage must be optimal for cost-efficient storage of hydrogen.[9,10] There are three leading approaches for utilization of stored H_2 for power generation, and they are co-injection with natural gas in an existing natural gas combined cycle (NGCC) power plant, firing of H_2 by itself in a turbine, and use it in a fuel cell. Co-injection of H_2 with natural gas facilitates use of existing gas turbines in NGCC plants and existing infrastructure. While many existing gas turbine frames have the capability of using reasonably large percentage of H_2 without considerable upgrade, firing of pure H_2 can be challenging in existing frames without considerable upgrade of H_2 as well as modification of the heat recovery steam generator (HRSG). When H_2 is fired by itself, it can be used under simple cycle or combined cycle modes. One of the early adapters for utilization of pure H_2 is expected to be the Peaker plants that operate under simple cycle mode. In this research, firing of H_2 in a Peaker plant is considered.

2.0 Configurations and Models of Hydrogen generation, storage, and utilization in the Peaker Plant

The process configuration for this work is shown in Figure 1. In this work, we aimed to optimally design a gas turbine that utilizes hydrogen generated from an alkaline electrolyzer and stored in a compressed hydrogen vessel. The optimal design of the vessel and the optimal operation of the electrolyzer and the gas turbine is considered for Peaker Plant and investigated in this work. Here, we developed a data driven model based on a high-fidelity model from the literature for the alkaline electrolyzer and the gas turbine. For this work, electricity from grid or renewable sources is considered for hydrogen production, and generated electricity is sold to the grid. The different component of the system is described below:

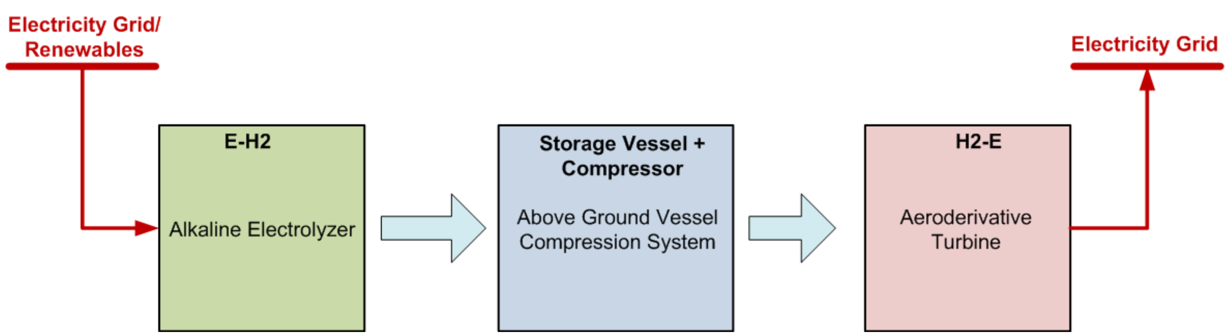

Figure 1. Process flow diagram.

2.1 H_2 Generation by Alkaline Electrolyzer

A high-fidelity Aspen Plus model of an alkaline electrolyser was developed by Sanchez et. al. 2020.[11] The model was a hybrid of empirical model developed in ACM and unit operation models in Aspen Plus. Faradaic efficiencies and the coefficients of the polarization curve and gas purity used for building the empirical model has earlier been validated with experimental data by the authors. The model included the balance of plant for the complete generation of hydrogen using alkaline electrolyzer. In the model, it was assumed that all processes operate at a steady state. An ideal gas behavior is assumed for the gases. Deionized water is fed into the system at 25ºC, and the hydrogen and oxygen output are obtained at 25˚C. The alkaline electrolyzer is operated at balanced anode and cathode pressure. The data available from this reference is used to develop a data-driven model of the electrolyzer.

From the above reference[11], it is observed that there is a linear relationship between current density and hydrogen flowrate. As the current density increases, the hydrogen flowrate increases. Our main aim was to find the relationship between hydrogen production rate and specific power consumption of the electrolyzer. We therefore explore the result provided from the aspen model showing the relationship between the specific consumption and current density. The data for the specific consumption to model the relationship between hydrogen production rate and specific consumption was extracted and utilized in the development of electrolyzer model. Figure 2 shows the schematic of an alkaline water electrolyzer system.

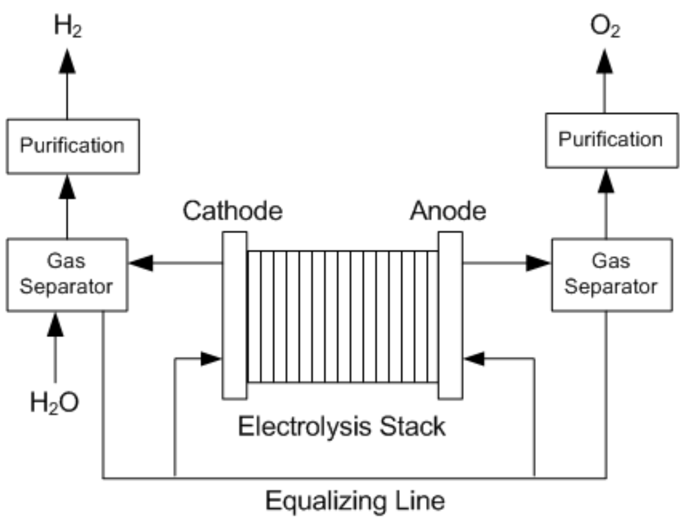

Figure 2. A schematic flow diagram of an alkaline water electrolyzer.

2.1.1 Data Driven Model of Alkaline Water Electrolyzer

Electrolyzer utilization (EU) can be represented by Eq. 1, i.e., in terms of relative current density or, equivalently, in terms of H_2 production rate as shown in Eq. 2.

$$EU = \frac{Current\ Density_i}{Max\ Current\ Density} \quad (1)$$

$$EU = \frac{Hydrogen\ Producdtion\ rate_i}{Max\ Hydrogen\ Production\ rate} \quad (2)$$

Also, we converted the specific consumption from $\frac{kWh}{Nm^3}$ to $\frac{kWh}{kg}$ because of convenience. Figure 3 shows the fit of a 3rd order polynomial model to the data.[11] This model is represented in Eq. 3, where SC represents the specific consumption in $\frac{kWh}{kg}$.

$$SC = 89.54 - 135.17EU + 189.04EU^2 - 80.76EU^3 \quad (3)$$

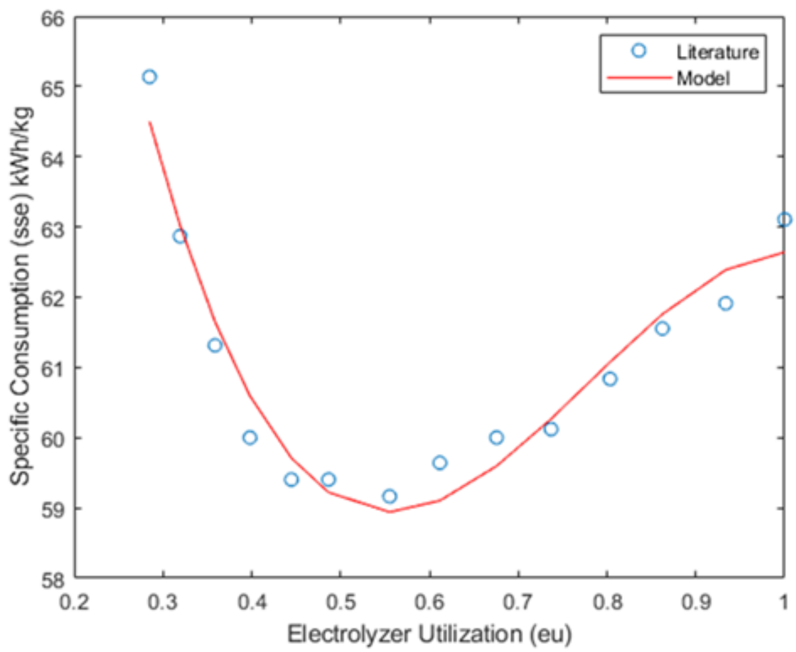

Figure 3. Developed model of alkaline water electrolyzer.

2.1.2 Costing Model for The Alkaline Water Electrolyzer

Caponi et. al.[12] analyzed the cost of generating hydrogen based on industrial data from multiple sources by using the Monte-Carlo approach. They divided the cost of production into low, mid, and high regime. In the current set-up, we use a value of \$988/kW for the evaluation of the electrolyzer CAPEX. This value falls in the mid region of the capital cost study. In this work, the fixed operating and maintenance cost is specified to be \$40/kW while the variable operating, and maintenance is 0.08\$/kg of hydrogen produced. Eqns (4) – (6) shows the CAPEX, fixed O&M and variable O&M cost model of the alkaline electrolyzer.

$$Electrolyzer_{CAPEX} = 988 * Capacity\ of\ the\ electrolyzer \tag{4}$$

$$Electrolyze\ Fixed\ O\&M = 40 * Capacity\ of\ the\ electrolyzer \tag{5}$$

$$Electrolyze\ Var.O\&M_h = 0.08 * H_2Flowrate_h \tag{6}$$

2.2 H_2 Storage System

2.2.1 Optimal Design of H_2 Storage Model

Table 1 shows various options for H_2 storage system. Optimal selection of hydrogen storage systems is essential for a robust hydrogen economy.[13,14] Hydrogen can be stored physically as either a gas or a liquid. Storage of hydrogen as a gas typically requires high-pressure (350–700 bar) for economic reasons. Storage of hydrogen as a liquid requires cryogenic temperatures because the boiling point of hydrogen at atmospheric condition is −252.8°C. Hydrogen can also be stored on the surfaces of solids (by adsorption) or within solids (by absorption).[13] Compressed gas storage is the most mature technology for hydrogen storage. There are four types of high-pressure vessels used for storing hydrogen gas as listed in Table 2.

Table 1. List of Options for Hydrogen Storage[15]

Methods of Storing Hydrogen	
Physical-based	Compressed Gas
	Cold/Cyro Compressed
	Liquid Hydrogen
Material-based	Adsorbent
	Liquid Organic
	Interstitial hydride
	Complex hydride
	Chemical hydrogen

Table 2. Type of Vessels for Storing Hydrogen as a Compressed gas

Type I	Pressure vessel made of metal
Type II	Pressure vessel made of thick metallic liner hoop wrapped with a fiber-resin composite
Type III	Pressure vessel made of a metallic liner fully wrapped with a fiber-resin composite
Type IV	Pressure vessel made of polymeric liner fully wrapped with a fiber-resin composite. The port is metallic and integrated into the structure

The decision on which vessel to use for hydrogen storage depends on the final application of hydrogen. Even though Type III and Type IV have the potential to store hydrogen at a very high pressure and small volumes, they are often used in mobile systems because of their seemingly light weight. To build a Type I vessel (which is the cheapest and most common) of high pressure of about 300 bar, the weight of the vessel is generally high, which is acceptable for stationary application. The vessel type selection is a compromise between technical performance and cost-competitiveness.[8] There are multiple study on the economic model of hydrogen storage[10,13] and most of the works are based on the vendor quotes and therefore not suitable for optimizing the vessel design conditions. In this research, vessels are sized with due consideration of the stress and capacity and their costs are calculated by considering pressure and material factor as well as commercial data thus making it suitable for NPV optimization.

Compressed hydrogen gas is mostly stored using cylindrical vessel. Eqs. 7-17 are the design equations which are used for determining optimum vessel configuration. The minimum thickness is given by t_u, and minimum thickness required based on the circumferential stress and longitudinal stress are given by t_c and t_l, respectively. The maximum of these three thickness is usually considered as the required thickness to which corrosion allowance is added to obtain the final thickness as shown in Eq. 12. The welding efficiency (E) and the allowable stress (S) are dependent on the material of construction of the vessel and the condition of storage.

Table 3. Design Equation of the Hydrogen Storage Vessel Shell

$V_{H2} = \pi R^2 L$	(7)
$t_u = 1.5\ mm$	
$t_c = \frac{PR}{SE-0.6P}$; if P ≤ 0.385 SE	(8)
$t_c = R\left(e^{\frac{P}{SE}} - 1\right)$; if P > 0.385 SE	(9)
$t_l = \frac{PR}{2SE+0.4P}$; if P ≤ 0.385 SE	(10)
$t_l = R\left(\sqrt{\frac{P}{SE}+1} - 1\right)$; if P ≤ 0.385 SE	(11)
$t = \text{maximum}(\mathrm{t_c}, t_l, t_u)$	(12)
$t_d = t + corossion\ allowance$	(13)
$t_n > t_d$	(14)
$t_{nc} = t_n - corossion\ allowance$	(15)
$Vm = \pi L(Ro^2 - R^2)$	(16)
$R_o = t + R$	(17)

The external thickness of the vessel is calculated by Eq. 17 and the volume of metal for the vessel shell is calculated using Eq. 16. The maximum allowable working pressure (MAWP) of the vessel is computed using the nominal thickness of the vessel and the nominal thickness must be greater than the design thickness of the vessel. Upon accounting for corrosion, the MAWP is estimated using Eq. 20-21. The minimum of the circumferential MAWP and longitudinal MAWP is used as the MAWP for the vessel. Equation 18 and 19 are used to estimate the thickness required for a hemispherical head. Eq. 22 is used to calculate the volume of the metal for the vessel head. The overall volume and mass of the metal are calculated using Eq. 23 and 24 respectively. In order to account for other materials needed for construction such as vessel supports, nozzles, mesh etc., a factor is added to calculate the gross weight as shown in Eq. 25.

Table 4. Design Equation of the Hydrogen Storage Vessel Head

$t = \frac{PR}{2SE-0.2P}$; if P ≤ 0.665 SE	(18)
$t = R\left(e^{\frac{0.5P}{SE}} - 1\right)$; if P > 0.665 SE	(19)
$MAWP = \frac{2SEt_{nc}}{R-0.4t_{nc}}$; if t ≤0.356R	(20)
$MAWP = 2SElog_e\left(\frac{R+t_{nc}}{R}\right)$; if t > 0.356R	(21)
$V_{mh} = \frac{2\pi(R_O^3-R^3)}{3}$	(22)
$V_t = V_m + 2V_{mh}$	(23)
$W = Density\ of\ Material * V_t$	(24)
$W_{gross} = W\left(1 + \frac{F}{100}\right)$	(25)

2.2.2 Cost Model of Hydrogen Storage Vessel

Equations needed for cost calculations are shown in Eq. 26-34. Two of the most popular approach in the literature is the Lang factor approach and the module factor approach. The Lang factor approach is shown in Eq. 27. For fluid processing plant, the lang factor is 4.74, which can be used for H_2 storage vessels. But the module factor approach is considered in this study because Lang factor is often when an equipment has already being purchased (when the cost of the equipment is already known) while the bare module approach can also estimate the cost of the equipment. The bare module cost is given by Eq. 28. The total module cost is given by Eq. 29. Eqn. 31-34 represent additional terms including those used for considering the material of construction and operating pressure.

Table 5. Capital Cost Equation of Hydrogen Storage Vessel

$C_{p,veseel} = C_p^o\, F_p F_M$	(26)
$C_{TM} = F_{lang} \sum C_{p,vessel}$	(27)
$C_{BM} = C_p^o\, F_{BM}$	(28)
$C_{TM} = 1.18 \sum C_{BM}$	(29)
$\log_{10} C_p^o = K_1 + K_2 \log_{10} A + K_3\, (\log_{10} A)^2$	(30)

$F_{P,Vessel} = 1$; for $t_{vessel} < t_{min}$; $P > -0.5barg$	(31)
$F_{P,Vessel} = \frac{\frac{(P+1)D}{2[850-0.6(P+1)]}+0.00315}{0.0063}$; for $t_{vessel} > t_{min}$; $P > -0.5barg$	(32)
$F_{P,Vessel} = 1.25$; for $P < -0.5barg$	(33)
$F_{BM} = B_1 + B_2 F_p F_M$	(34)

The hydrogen storage vessel is optimized by employing formulations in which the objective function set to minimize CAPEX, with constraints pertaining to the design pressure and volume.

$$min\ C_{TM} \tag{35}$$

$$\text{s.t. } V_t = \frac{Z m_{H2} R T}{P_{H2} M_{H2}}$$

2.3 H_2 Utilization in the Gas Turbine Model

A polynomial model was developed to capture the operational efficiency of the aeroderivative turbine. This model shows the operating relationship between the thermal efficiency and the power output of the LM2500 aeroderivative turbine of GE Energy (General Electric).[16,17] This model helped us to create a relationship that captures the amount of hydrogen injected into the gas turbine to produce a certain amount of power from the gas turbine. The gas turbine fuel is assumed to be a mixture of hydrogen and natural gas. In this case the lower heating values of both hydrogen and natural gas is involved in the computation of the operational efficiency, power generation and fuel consumption. Just as with the case with 100% natural gas injection, we applied similar equations but here we also accounted for the presence of natural gas in the fuel mix. The volumetric percentage of the fuel is x (Eq. 36-37), and this can be used to compute the injection rate of each of the fuel (H_2 and NG). The adjustment to this formulation is shown in Table 6 and the developed model is shown in Figure 4 and Eq. 36.

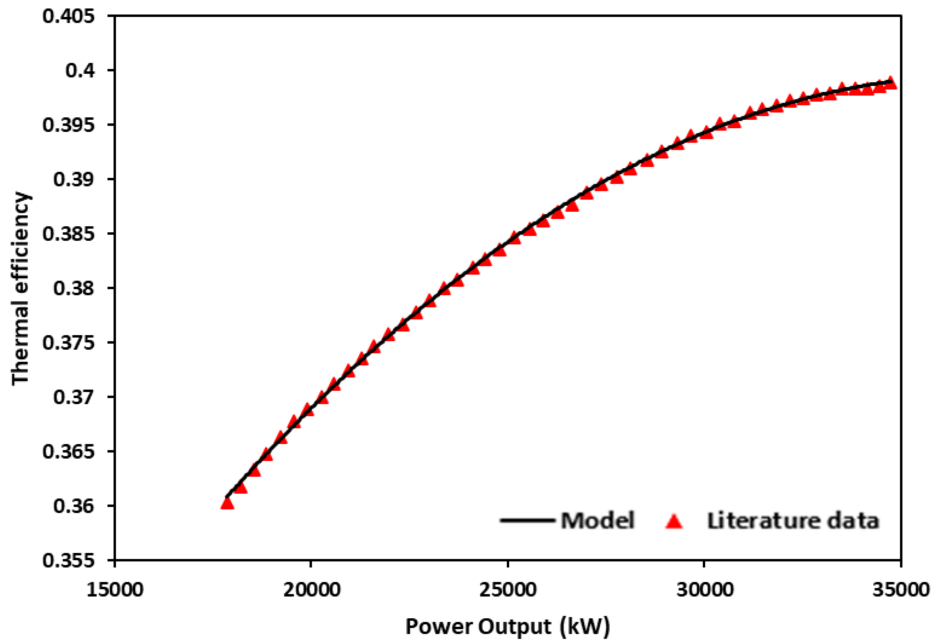

Figure 4. Developed model of aeroderivative turbine.

$$Eff = 0.2556 + 8e^{-6}P_{output} + 1e^{-10}P_{output}^2 + +0.2556 \quad (36)$$

Table 6. Aeroderivative Gas Turbine Model

$Fuel\ injection\ rate_f \left(\frac{kg}{hr}\right) = x_f \rho_f V_T$	(37)
$\sum_{f \in H_2,NG} x_f = 100$	(38)
$Thermal\ Efficiency = \frac{Work\ Output(Power\ produced)\ MW_e}{Heat\ Input\ MW_{th}}$	(39)
$Heat\ Input\ (MW_{th}) = \sum_{f \in H_2,NG} LHV_f * Fuel\ injection\ rate_f$	(40)

2.3.1 Cost Model of Gas Turbine

The capital cost of the aeroderivative gas turbine is estimated at \$1000/kW power produced.[18] Also, the fixed OPEX of the gas turbine is a fraction of the CAPEX and the variable OPEX is a function of the power produced by the turbine at every point in time. The cost model equations of gas turbine are listed in Table 7 (Eq. 41-43).

Table 7. Costing Model for Aeroderivative Gas Turbine [13,18]

$GT_{CAPEX} = 1000 * Capacity_{GT}$	(41)
$GT_{fixed\ OPEX} = 0.0153 * GT_{CAPEX}$	(42)
$GT_{var\ OPEX} = 0.695 * P_{GT}$	(43)

3.0 Process Optimization

3.1 Locational Marginal Price (LMP)

This study utilized a yearlong dataset of dynamic locational marginal price (LMP) of CAISO (California Independent System Operator) regions. The LMP data, obtained from NREL[19] incorporates a consideration of a 100 $/ton carbon tax. Given the computationally expensive nature of hourly dynamic data spanning a year, a cluster algorithm was employed to determine equivalent days, reducing the data set to 131 days instead of 365. This algorithm put similar days in the same cluster upon satisfaction of the tolerances and retains the NPV optimization results within ±10% error compared to the non-clustered value.

To ensure profitability of a peaker plant, it is essential that the difference between high LMP × duration and low LMP × duration is substantial. Therefore, a modified LMP was developed based on CAISO-100 data using a formulation in Eq. 44. This formulation applies to electricity price at or above 20 $/MWh and yields a higher difference between high and low LMP values. Figure 5 illustrates a comparative profile of the original and modified LMP datasets over a span of 5000 hrs. Similar to LMP values, clustered modified LMP with 131 equivalent days were used in the study.

$$Modified\ LMP\ for\ Peaker\ Plant = LMP_{reg} + OPEX_{NGCC}^{var} * \left(\frac{\eta_{NGCC}}{\eta_{Peaker}} - 1\right) \quad (44)$$

Where, $OPEX_{NGCC}^{var}$ is associated with NG cost.

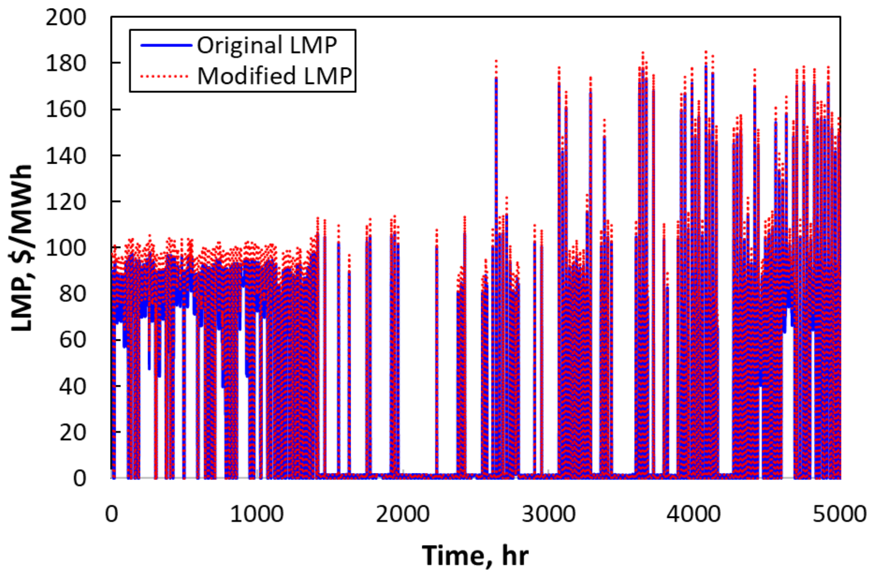

Figure 5. Modified LMP profile for CAISO-100 region.

3.2 Renewable Energy Price

Beside the LMP data, this study incorporates renewable energy (solar energy) data for H_2 using alkaline water electrolyzer. The investigation aimed to understand how renewable energy influences the profitability of the peaker plant. The Energy Efficiency & Renewable Energy (EERE) has established 2030 Solar Cost Targets, and this study adopts these targets as the energy cost for H_2 production. The data is presented as levelized cost of energy (LCOE) for solar energy ranging from 16 \$/MWh to 26 \$/MWh with 20 \$/MWh being the median price. [20,21]

3.3 Optimization Framework

The net present value of the hydrogen utilization gas turbine integrated with hydrogen production and storage system is optimally computed putting into account all the constraints imposed by the operational models of the units that made up the plant. The individual models were integrated in the Python/PYOMO platform and a popular NLP solver IPOPT for large scale optimization was chosen for this study. The operational models enable us to compute the variable operational expenditure of the plant's units, and this is a function of either the hydrogen produced for the electrolyzer, or the power generated for the gas turbine. The objective function (Table 8, Eq. 45) being optimized in this case is the NPV of the plant. The assumed discount rate is 7.25% and the plant expected year of operation is 30 years. These parameters are used to calculate the present annuity factor that we eventually used to scale down the capital expenditure to hourly rate.

Table 8. Objective Function of the Integrated Peaker Plant

$$\max NPV = P_{A,f} \sum_{t=1}^{8760} REVENUE_t - CAPEX_t - P_{A,f}\, OPEX_{fixed} \quad (45)$$

$$s.t.\ \forall\, t \in T\ REVENUE_t = LMP_t P_{grid,t} - LMP_t P_{consumed,t} - OPEX_{variable,t} \quad (46)$$

$$\forall\, t \in T\ P_{grid,t} = GT\ power\ produced \quad (47)$$

$$\forall\, t \in T\ P_{consumed,\,t} = Electrolyzer\ + H_2\ Compressor \quad (48)$$

$$P_{A,f} = \frac{(1+i)^n - 1}{i(1+i)^n} \cdot \frac{1}{(1+i)^n} \quad (49)$$

$$\forall\, t \in T\ CAPEX_t = \frac{CAPEX}{365*24*P_{A,f}} \quad (50)$$

$$OPEX_{fixed} = \frac{OPEX_{fixed}}{365*24} \quad (51)$$

$$\forall\, t \in T\ \rho_{H2,initial} = \rho_{H2,final} \quad (52)$$

$$\forall\, t \in T\ H_2\ Injection\ rate * H_2\ Production\ rate \leq 100 \quad (53)$$

The constraints involved in the optimization are the operating models of the alkaline water electrolyzer, hydrogen compressors, and the aeroderivative gas turbine. Another important constraint that we added to ensure that the operation of the electrolyzer and the gas turbine is mutually exclusive is shown in the Eq. 52.

3.3 Optimization Scenarios

For this studies, four scenarios were considered, and solved for entire year, and they are:

Scenario-1: NPV optimization with clustered LMP
Scenario-2: NPV optimization with modified clustered LMP
Scenario-3: NPV optimization with renewable energy price
Scenario-4: NPV optimization with variable cost data

Scenario-1: NPV optimization with clustered LMP

In this scenario, four cases have been examined, and Table 9 provides the configuration details for each case. Carbon tax is applied for case-1 and 2, while case-3 and 4 do not include it. Hydrogen is injected with NG into the turbine at a fixed rate of 20 vol% for case-1 and 3, whereas it varies from 0 to 20 vol% for case-2 and 4. Similar studies have been conducted for 15 vol% hydrogen injection and the results can be found in the Appendix (Table A1, Figure A1-A3).

Table 9. Case Configurations for Clustered LMP Data

Parameters	Case-1	Case-2	Case-3	Case-4
CO_2 Tax ($/ton)	100	100	0	0
H_2 as Fuel (vol%)	20	0-20	20	0-20

Scenario-2: NPV optimization with modified clustered LMP

Similar case configurations were applied for modified clustered LMP data, and these cases are named as case-5, and case-6.

Table 10. Case Configurations for Modified Clustered LMP Data

Parameters	Case-5	Case-6
CO_2 Tax ($/ton)	100	100
H_2 as Fuel (vol%)	20	0-20

Scenario-3: NPV optimization with renewable energy price

In scenario-3, a LCOE of solar energy 16 $/MWh is utilized as the electricity cost for H_2 generation by an alkaline electrolyzer for both 8 hrs and 12 hrs, denoted as case-9 to case-15. For case-9 to case-12, 8 hrs of H_2 generation are considered, and the remaining time (16 hrs on a daily basis) is allocated for power generation by gas turbine. Similarly, case-13 to case-15 utilized 12 hrs for power generation. The highest values from modified CAISO-100 LMP are taken as the selling price of electricity. Case-7 and 8 are considered as a base case for this scenario with or without carbon tax, serving as points of comparison with other cases. Table 11 presents the details of each case configuration.

Table 11. Case Configurations for Renewable Energy Price Data

Parameters	Case-7	Case-8	Case-9	Case-10	Case-11	Case-12	Case-13	Case-14	Case-15
CO_2 Tax ($/ton)	100	0	100	100	0	0	100	100	0
H_2 as Fuel (vol%)	0	0	20	0-20	20	0-20	20	0-20	20
Duration of H_2 Genaration (hr)	0	0	8	8	8	8	12	12	12

Scenario-4: NPV optimization with variable cost data

The details of each case configuration for this scenario are outlined in Table 12. In this table, the electricity buying price is set at 20 $/MWh, and selling prices are considered at 40$/MWh and 60$/MWh, respectively. Notably, the gas turbine capacity is adjusted to 57 MW, deviating from the 50 MW in scenario-1, 2, and 3. Additionally, H_2 injection is maintained at 20 vol%, and other cost components are specified in the table.

Table 12. Case Configurations for Variable Cost Data

Parameters	Case-16	Case-17	Case-18	Case-19	Case-20	Case-21	Case-22	Case-23	Case-24
H_2 Production Price ($/MWh)	20	20	20	20	20	20	20	20	20
Elect. Selling Price ($/MWh)	40	40	60	60	60	60	60	60	40
Electrolyzer Cost ($/KWh)	1,000	1,000	1,000	1,000	500	500	1,000	1,000	1,000
Storage+Comp. Cost ($/kg H_2)	1,500	500	1,500	500	500	500	500	1,500	500
Turbine Cost ($MM)	30	30	30	30	30	0	0	0	0
Turbine Capacity (MW)	57	57	57	57	57	57	57	57	57

3.4 Sensitivity Analysis

A sensitivity analysis was performed by varying the LCOE of solar energy across a range from 16 \$/MWh to 26 \$/MWh. This analysis aimed to observe the effects on NPV of the integrated process. The study specifically focused on cases involving 8 hrs of H_2 generation, considering both scenarios with and without carbon tax considerations.

4.0 Results and Discussions

In this section, NPV optimization results derived from the scenarios discussed in the previous section are generated and subsequently discussed.

Scenario-1: NPV optimization with clustered LMP

The NPV optimization for the clustered LMP of CAISO-100 region is conducted for the entire year, following the optimization framework outlined in Table 9. The results are tabulated in Table 13. In case-1, an electrolyzer with a maximum capacity of 16.18 MW is placed, and the gas turbine generates a maximum power of 41.34 MW. As storage pressure is high 219 bar, it incurs a high capital investment. For case-2, where the H_2 injection rate varies from 0 to 20 vol%, electrolyzer is not placed and the values are close to the lower bound of 2 MW. In this case, NG dominates power generation due to its lower cost compared to H_2 generation. With a lower CAPEX in case-2 compared to case-1, the NPV increases to 2.77 \$MM from case-1. For case-3 and 4, where no carbon tax is applied, the results are superior to case-1 and 2, indicating that carbon tax is a significant contributing factor. When comparing results between case-1 and 3; and case-2, and 4; it is observed that carbon tax plays significant role in NPV values.

Table 13. NPV Optimization Results for Scenario-1

Design Variables	Case-1	Case-2	Case-3	Case-4
Max H_2 Production, kg/h	258.21	35.35	322.76	48.23
Max Electrolyzer Power, MW	16.18	2.21	20.22	3.02
H_2 Volume, m^3	179.68	318.95	179.68	322.65
H_2 Storage Pressure, bar	219.08	100.46	219.08	122
Max GT Power, MW	41.34	50	39.47	50
NPV, $MM	0.39	2.77	2.18	6.0

Figure 6 presents the model profiles for case-1. Specifically, Figure 6(b) illustrates the gas turbine (GT) power profile for the entire year, while Figure 6(a) zooms in on the profile for the first 300 hrs. In Figure 6(a), it is evident that the GT is generates power when LMP values are high and goes for shutdown mode during periods of low LMP's. Similarly, Figure 6(c) depicts H_2 profile, showcasing that H2 is generated during periods of low LMPs and injected during high LMP's, thereby contributing to power generation. Figure 6(d) provides insight into the amount of H_2 and NG as well as the total fuel flowrate to the turbine.

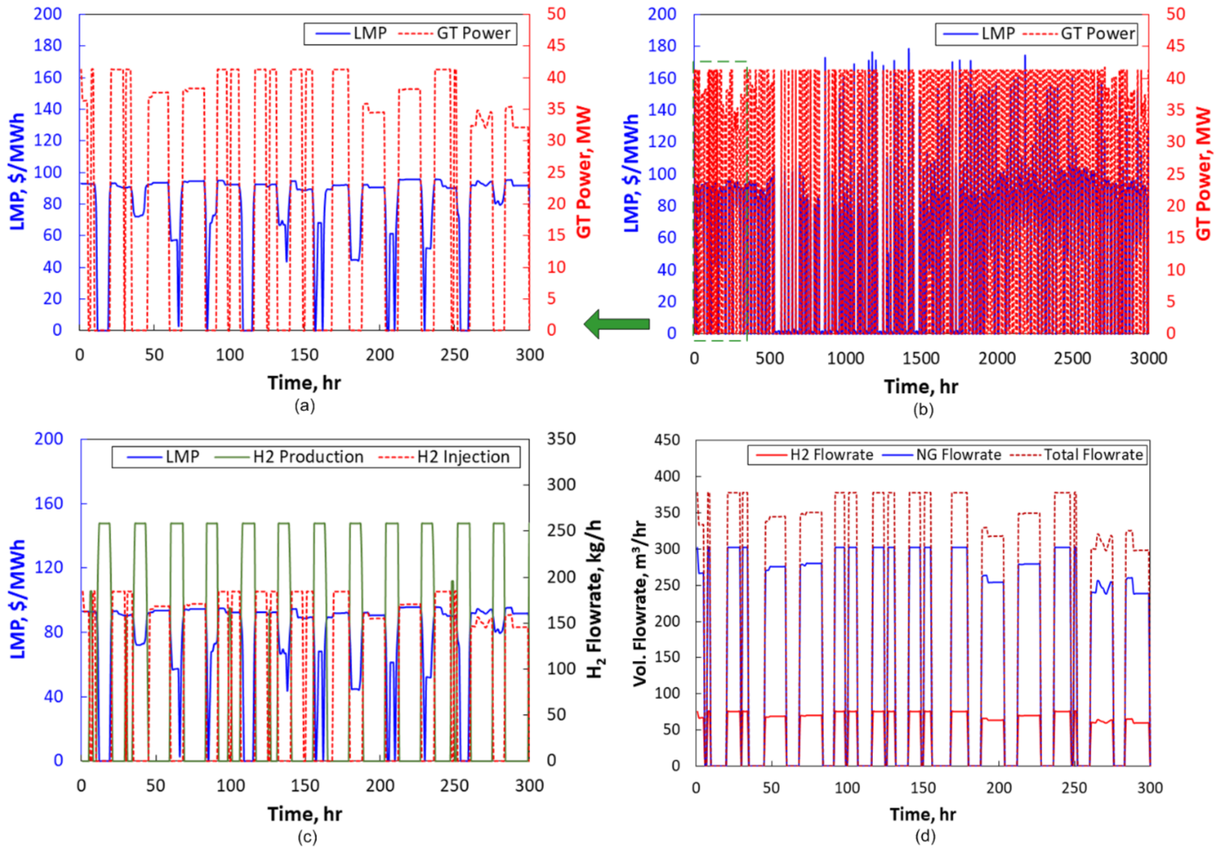

Figure 6. Case-1 20% Model profile for clustered LMP of CAISO-100 region.

Figure 7 shows the profiles for case-2. The main difference is observed by Figure 7(a) is that the turbine consistently operates with LMP profiles and always reaches the maximum capacity of 50 MW, unlike case-1. Since, NG is more cost-effective than H_2 generation and dominates in case-2, the model optimally utilizes the turbine to its maximum capacity. This is evident in the turbine operating with LMP profiles, maximizing its utilization. Comparing H_2 production and injection profiles from Figure 6(c) and 7(c), it is clear that NG is predominant in case-2. This is further supported by Figure 7(d) which shows a minimal amount of H_2 flowing to the turbine. Profiles for case-3 and case-4 can be found in the Appendix (Figure A4 & A5).

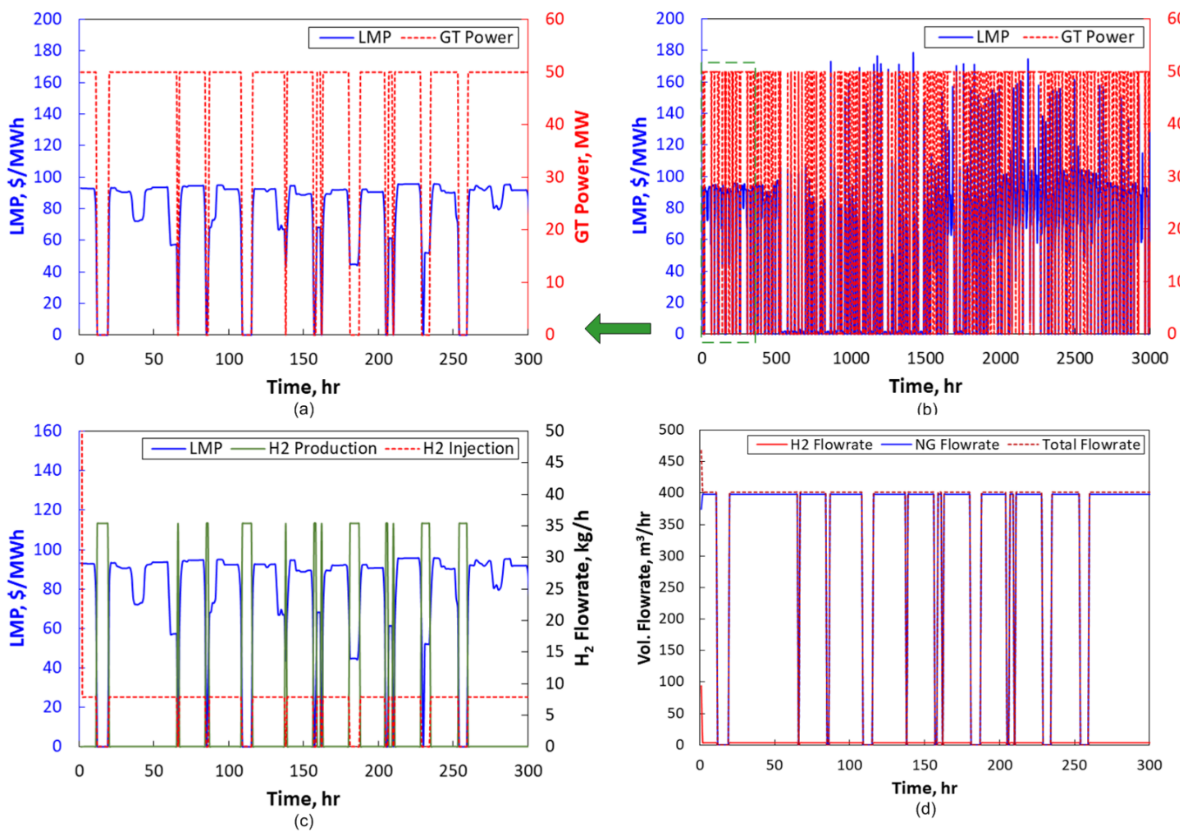

Figure 7. Case-2 20% Model profile for clustered LMP of CAISO-100 region.

Scenario-2: NPV optimization with modified clustered LMP

The LMP data for the CAISO-100 region is modified using proposed formulation (Eq. 44), as discussed earlier. NPV optimization is then conducted, and results are presented in Table 14. In this context, only two cases (case-5 and 6) with carbon tax are considered. Upon examination of the results, it is observed that the patterns are mostly similar to those of case-1 and 2 in scenario-1. However, there are notable differences. The storage pressure in case- and 6 is reduced to 100 bar, which is about 50% of case-1. This lower storage pressure results in a reduction in CAPEX, contributing to the NPV values. Additionally, this case using a higher electricity selling price compared to case-1 and 2, which also contributes to a slightly improved NPV value of 0.65 $MM.

Table 14. NPV Optimization Results for Scenario-2

Design Variables	Case-5	Case-6
Max H2 Production, kg/h	231.61	31.93
Max Electrolyzer Power, MW	14.51	2.0
H2 Volume, m3	393.63	77.0
H2 Storage Pressure, bar	100	84.92
Max GT Power, MW	35.8	50
NPV, $MM	0.65	3.60

Figure 8 illustrates the model profiles for the NPV optimization of modified LMP cases. Figure 8(a) focuses on the first 300 hrs, offering a snapshot of the entire year's profile (Figure 8(b)). The power profiles exhibit a similar pattern to case-1, varying with LMP values. Particularly, the turbine does not generate electricity at low LMP values, and in some periods, it enters shutdown mode when LMP values are in the range of 50-90 $/MWh. Figure 8(c) and 8(d) shows H_2 profile and volumetric fuel flowrate to the turbine, respectively. H_2 is produced at a rate of 231.61 kg/h when LMP is low, with an average injection rate of 145 kg/h. The blended fuel of NG and H_2 flowrate (Figure 8(d)) varies with turbine load and maintains a 20 vol% of H_2 flow.

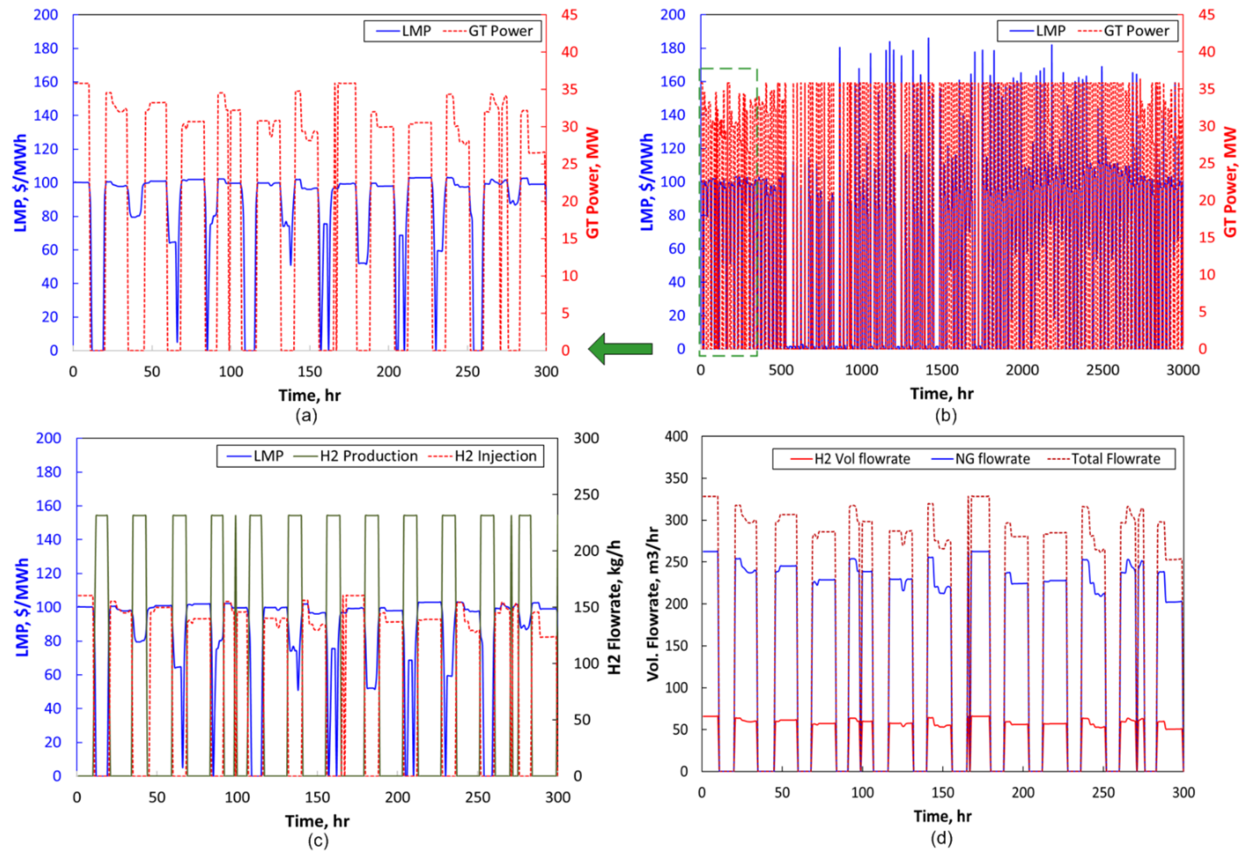

Figure 8. Model profile for modified clustered LMP of CAISO-100 region (case-5).

Scenario-3: NPV optimization with renewable energy price

Table 15 provides the results for the renewable energy sources cases. Specifically, case-9, 10, 11 and 12 shows the outcomes for 8 hr H_2 generation, while case-13, 14 and 15 are for 12 hr H_2 generation. Case-7 and 8 are considered as a base case with no H_2 utilization, relying entirely on NG as fuel for power generation. Consequently, these cases do not involve values for H_2 production and electrolyzer capacity. The NPV values for case-7 and 8 only differ due to carbon tax. Comparing case-9 and 10 with case-7 and 8 reveals a decrease in optimum NPV due to the inclusion of carbon tax and additional CAPEX. Similar to scenario-1 and 2, case-9 and 10 exhibit a similar pattern. The NPV of case-9 decreases due to H_2 injection, while case-10 remains largely the same compared to case-7, primarily relying on NG for power generation. Case-11, without carbon tax, shows an improved NPV compared to case-9 but less than case-8. Similarly, case-12 demonstrates similar values to case-8. Case-13, 14 and 15 (12 hrs H_2 generation cases) follow a similar pattern with a lesser improvement in NPV compared to case-9, 10 and 11.

Table 15. NPV Optimization Results for Renewable Cases

Design Variables	Case-7	Case-8	8 hrs H_2 Generation				12 hrs H_2 Generation		
			Case-9	Case-10	Case-11	Case-12	Case-13	Case-14	Case-15
Max H2 Production, kg/h	--	--	260.57	31.36	260.57	28.11	173.71	15.68	173.71
Max Electrolyzer Power, MW	--	--	16.32	2.0	16.32	2.0	10.88	2.0	10.88
H_2 Volume, m3	4.23	4.23	393.63	43.30	393.63	61.73	393.63	28.23	393.63
H_2 Storage Pressure, bar	69.25	69.25	100	68.53	100	82.54	100	74	100
Max GT Power, MW	50	50	28.24	50	28.24	50	38.94	50	38.94
NPV, $MM	33.1	43.79	16.04	33.06	20.93	43.59	16.63	23.51	21.52

Figure 9 and 10 present the model profiles for case-9 and case-10. It is observed that turbine power generates about 28 MW for case-9, while it reaches the upper limit 50 MW for case-10. This is happens because a fixed 20 vol% H_2 is injected into the turbine for case-9 whereas case-10 is utlizes mostly NG since H_2 injection is not fixed. In the same way, case-9 has higher H2 production as there is a constraint of 20 vol%, and this reduces significantly for case-10.

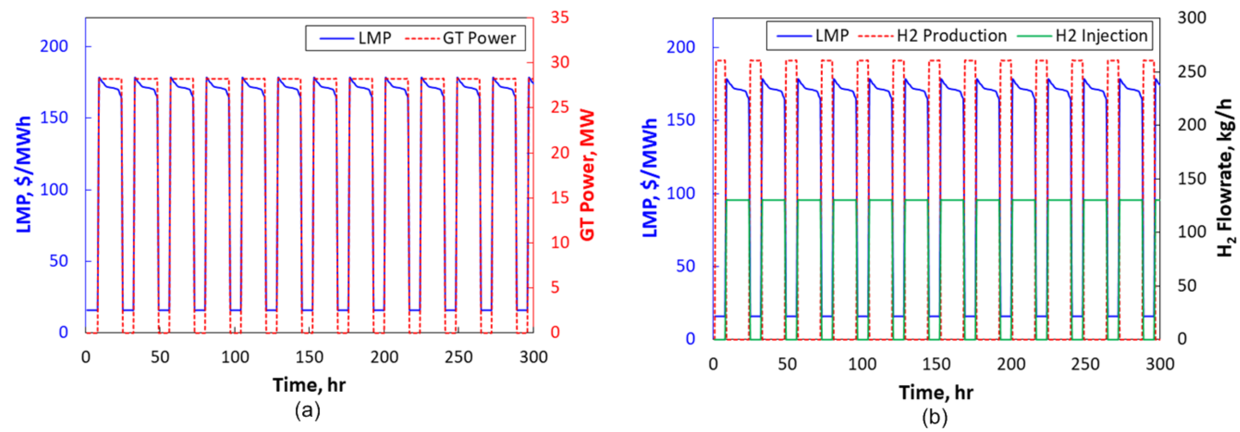

Figure 9. GT Power and H_2 profile for case-9.

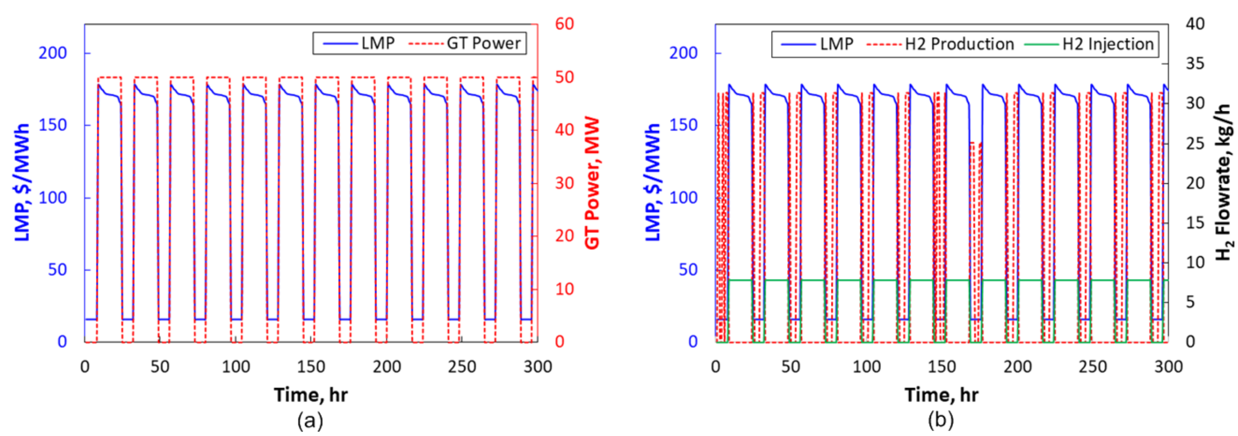

Figure 10. GT Power and H_2 profile for case-10.

Figures 11 and 12 shows the GT power and H_2 profile for case-13 and case-14, respectively. These cases involve 12 hrs H_2 generation and 12 hr power generation. In Figure 11(b), it is observed that H_2 production and injection rates are nearly same and power production increases compared to case-9 due to equal H_2 production and injection time. For case-14, GT power again reaches the maximum value, while H_2 production and injection reduces compared to case-13 due to the increased utilization of NG.

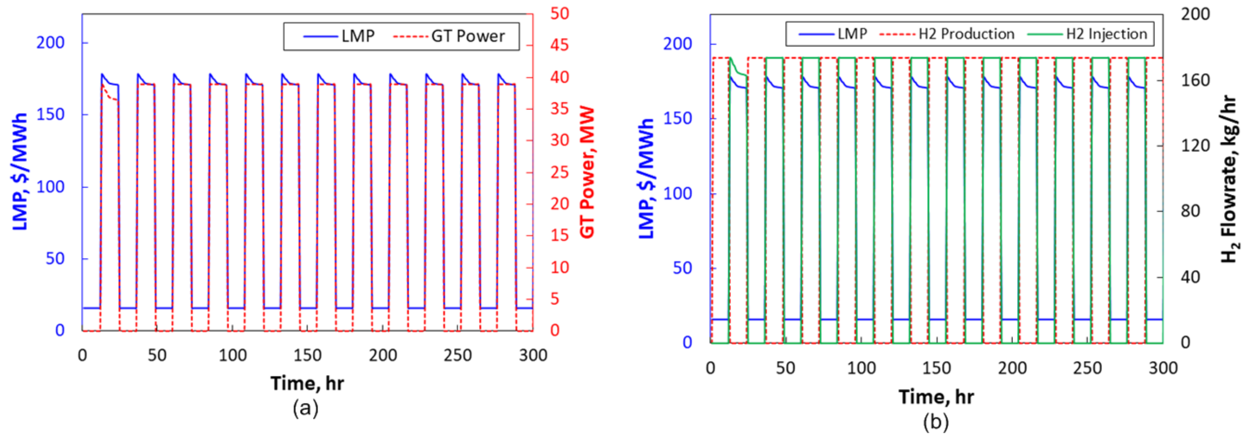

Figure 11. GT Power and H_2 profile for case-13.

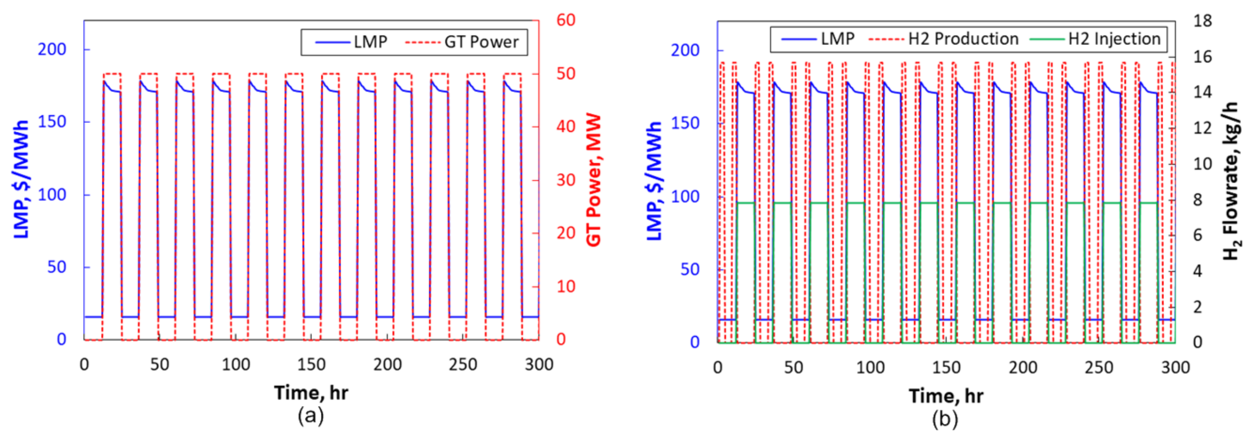

Figure 12. GT Power and H_2 profile for case-14.

Scenario-4: NPV optimization with variable cost data

In this scenario, NPV optimization is performed for case-16 to case-24, considering both with and without carbon tax. Table 16 shows the NPV results for all cases. Key design variables, such as electrolyzer capacity placed at 21.44 MW and the maximum mass of H_2 in the storage is 3486 kg, remain same across all cases. For this scenario, electricity buying price for H_2 generation is fixed at 20 \$/MWh, while the selling price to the grid is 40 \$/MWh and 60 \$/MWh. As mentioned before, the viability of the peaker plant is closely tied to the difference between high LMP values × duration and low LMP values × duration. In this particular scenario, this difference is small, impacting NPV values negatively across all cases. Furthermore, the fixed nature of most design variables in this scenario leads the optimizer to yield a trivial solution.

Table 16. NPV Optimization Results for variable cost data

Scenario	CO_2 Tax 0 $/ton NPV ($MM)	CO_2 Tax 100 $/ton NPV ($MM)
Case-16	-7.60	-8.98
Case-17	-6.94	-8.32
Case-18	-7.60	-8.98
Case-19	-6.94	-8.32
Case-20	-5.98	-7.36
Case-21	-3.28	-4.66
Case-22	-4.25	-5.62
Case-23	-4.91	-6.29
Case-24	-4.25	-5.63

Sensitivity Analysis

Figure 13 shows NPV results for different LCOE values of solar energy. In Figure 13, the results are presented for a fixed 20 vol% H_2 injection and 8 hrs H_2 generation. It is observed that both NPV with and without carbon tax exhibit a slightly decreasing trend with an increased energy cost. This trend suggests that the utilization of solar energy at a lower price could be beneficial for H_2 production and may have positive impact on the overall NPV of the integrated processes.

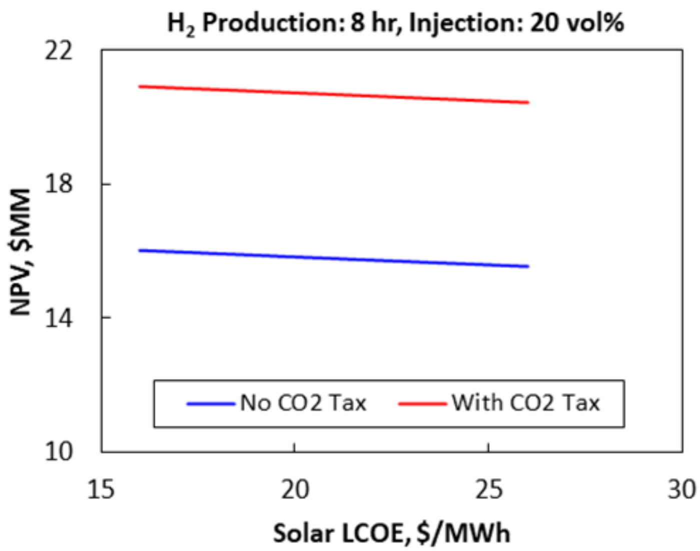

Figure 13. NPV comparison for SOLAR LCOE.

5.0 Conclusions

In this project, a techno-economic analysis was performed for an integrated process involving H_2 generation and utilization in a peaker plant. Individual models such as alkaline electrolyzer, H_2 storage and aeroderivative turbine were developed separately and then integrated within the Python platform. The integrated model was utilized for NPV optimization for different scenarios. With the exception of scenario-4, which explores the impact of varying individual unit costs on NPV and is found to be infeasible, all other scenarios yielded positive NPV values for the integrated process. In scenario-1, and 2, which are based on LMP and modified LMP, and scenario-3, which relies on renewable energy, the results indicate the potential of a viable peaker plant with utilization of blended fuel for power generation. As peaker plants typically operate during periods of high electricity demand, the electricity selling price for the peaker plant should be higher. To that end, scenario-2 introduces a modified LMP formulation to render the integrated process feasible. Scenario-3 results show slightly higher NPV values compared to scenario-1 and 2 indicating that the utilization of renewable sources for H_2 production and a higher electricity selling price could make the integrated process more promising.

Productivities

Publication

Haque, M.E.; Ijiyinka, I.S.; Senthamilselvan, P.; Feng, Z.; Bhattacharyya, D. Optimal Design and Operation of Hydrogen Generation and Storage System for Utilization in the Peaker Plant for a Time Varying Electricity Price Data. (In preparation).

Presentation

Haque, M.E.; Ijiyinka, I.S.; Senthamilselvan, P.; Feng, Z.; Bhattacharyya, D. Optimal Design and Operation of Hydrogen Generation and Storage System for Utilization in the Peaker Plant. Presented at the AIChE Annual Meeting, Orlando, FL, November 7, 2023.

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Acronyms and Abbreviations

ACM	Aspen Custom Modeler
CAISO	California Independent System Operator
CAPEX	Capital Expenditure
EU	Electrolyzer Utilization
GT	Gas Turbine
HRSG	Heat Recovery Steam Generator
LCOE	Levelized Cost of Energy
LMP	Locational Marginal Price
NG	Natural Gas
NGCC	Natural Gas Combined Cycle
NPV	Net Present Value
OPEX	Operating Expenditure
PEM	Proton Exchange Membrane

Appendix

Table A1 shows the NPV optimization results for 15 vol% H2 injection cases, which is similar to Scenario-1. Here, carbon tax 100 $/ton is applied for case-A1 & A2 while case-A3 & A4 are non-tax cases.

Table A1. NPV Optimization Results

Design Variables	Case-A1	Case-A2	Case-A3	Case-A4
Max H_2 Production, kg/h	71.86	15.96	322.76	0.01
Max Electrolyzer Power, MW	4.5	1.0	20.22	1.0
H_2 Volume, m^3	409.38	171.5	179.7	0
H_2 Storage Pressure, bar	96.5	90.0	219.1	47.0
Max GT Power, MW	33.25	50	50	50
NPV, $MM	0.30	3.71	9.0	15.4

Figure A1, A2 and A3 shows the model profile for 15 vol% H2 injection cases. Here, clustered LMP of CAISO-100 region is utilized. Based on this LMP, H2 will be generated at low LMP and generated power will be sold at high LMP period.

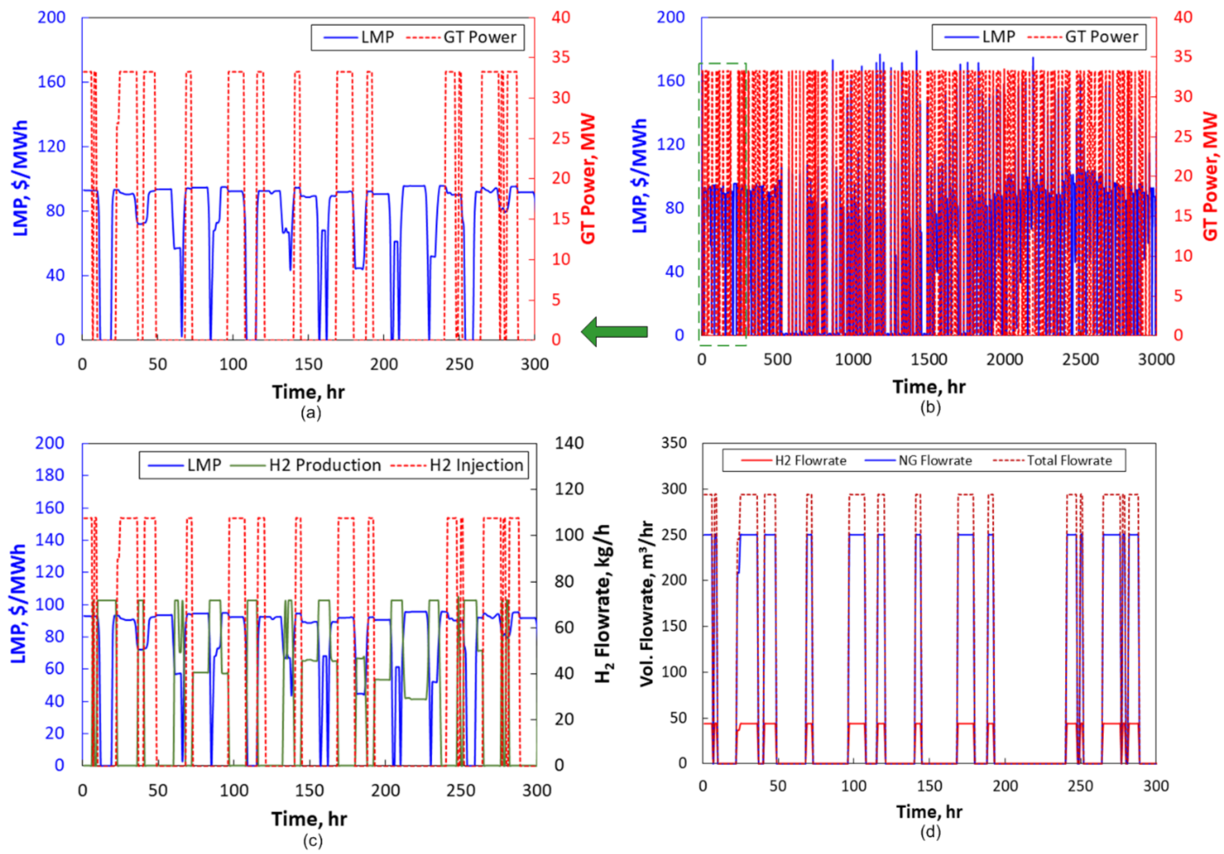

Figure A1. Model profile for case-A1.

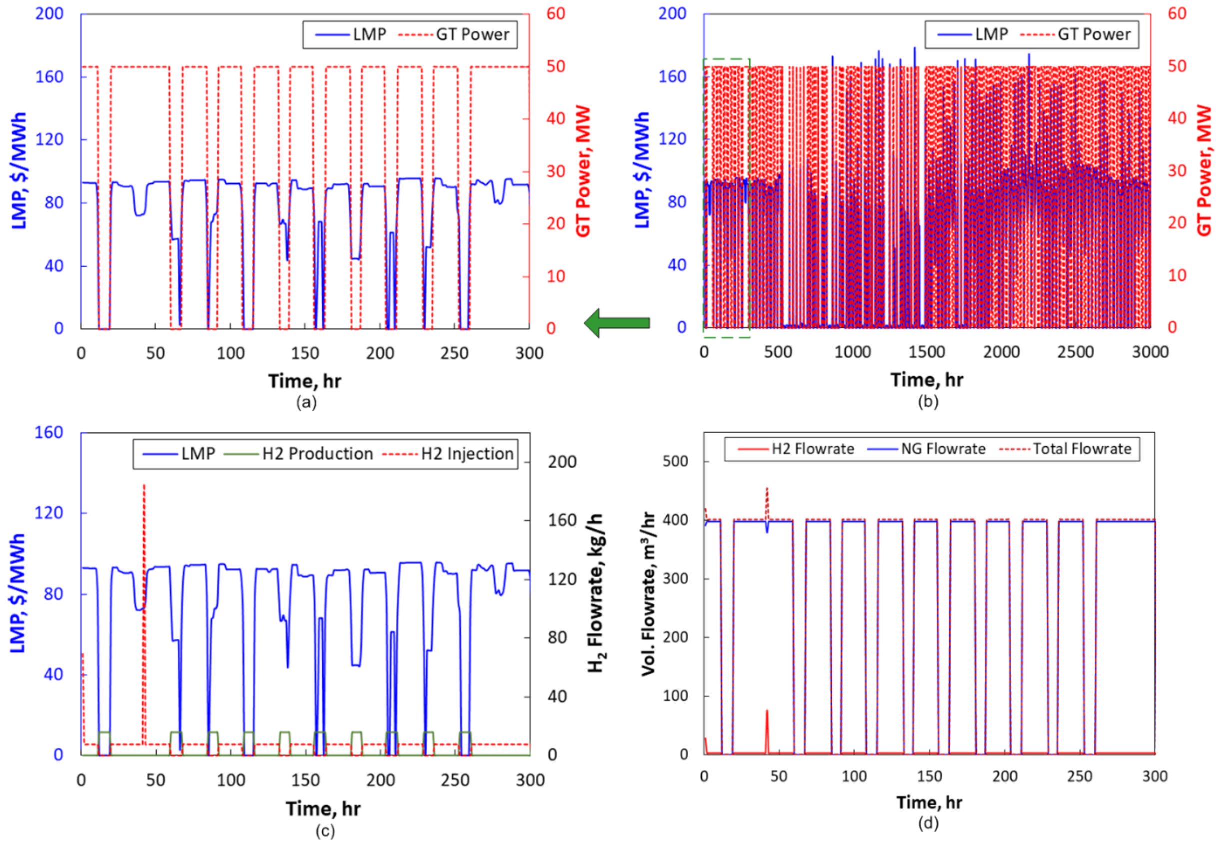

Figure A2. Model profile for case-A2.

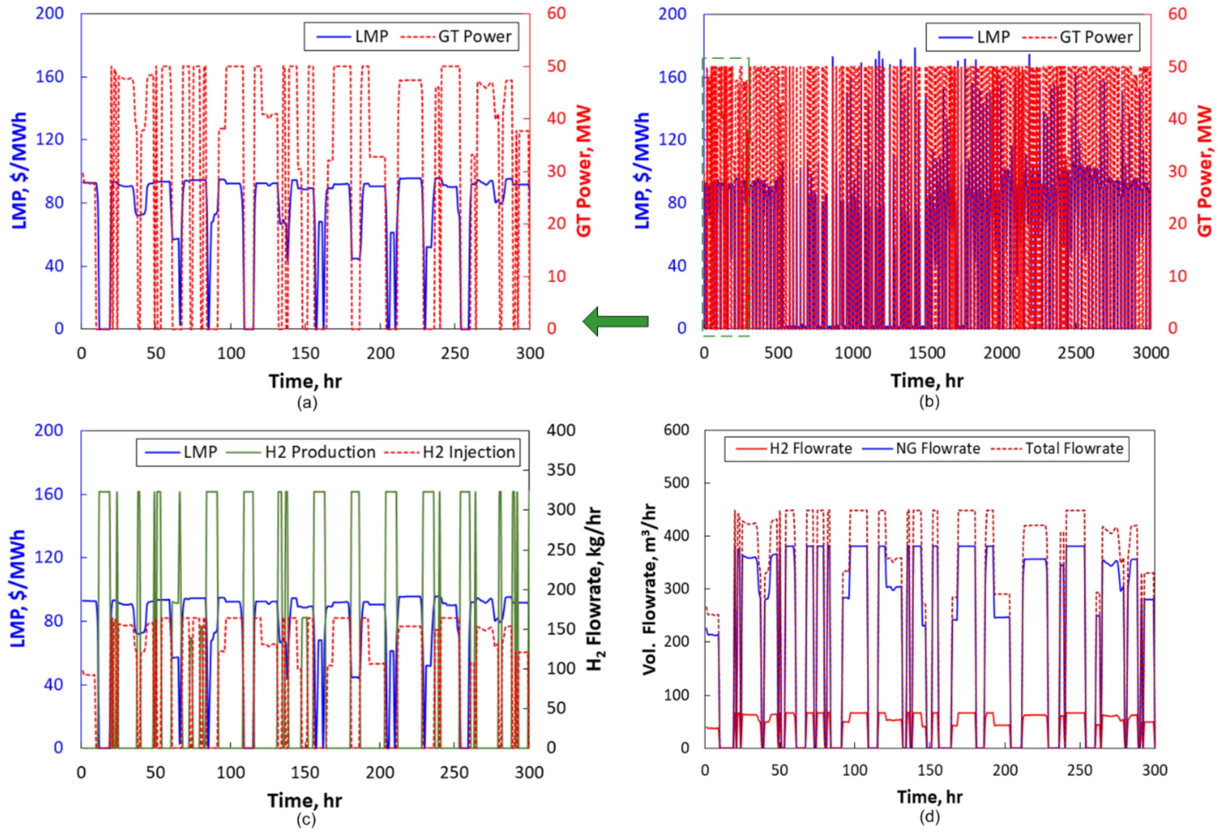

Figure A3. Model profile for case-A3.

Figure A4, and A5 shows the model profile for 20 vol% H2 injection cases (scenario-1). Here, clustered LMP of CAISO-100 region is utilized. Based on this LMP, H2 will be generated at low LMP, and generated power will be sold at high LMP period.

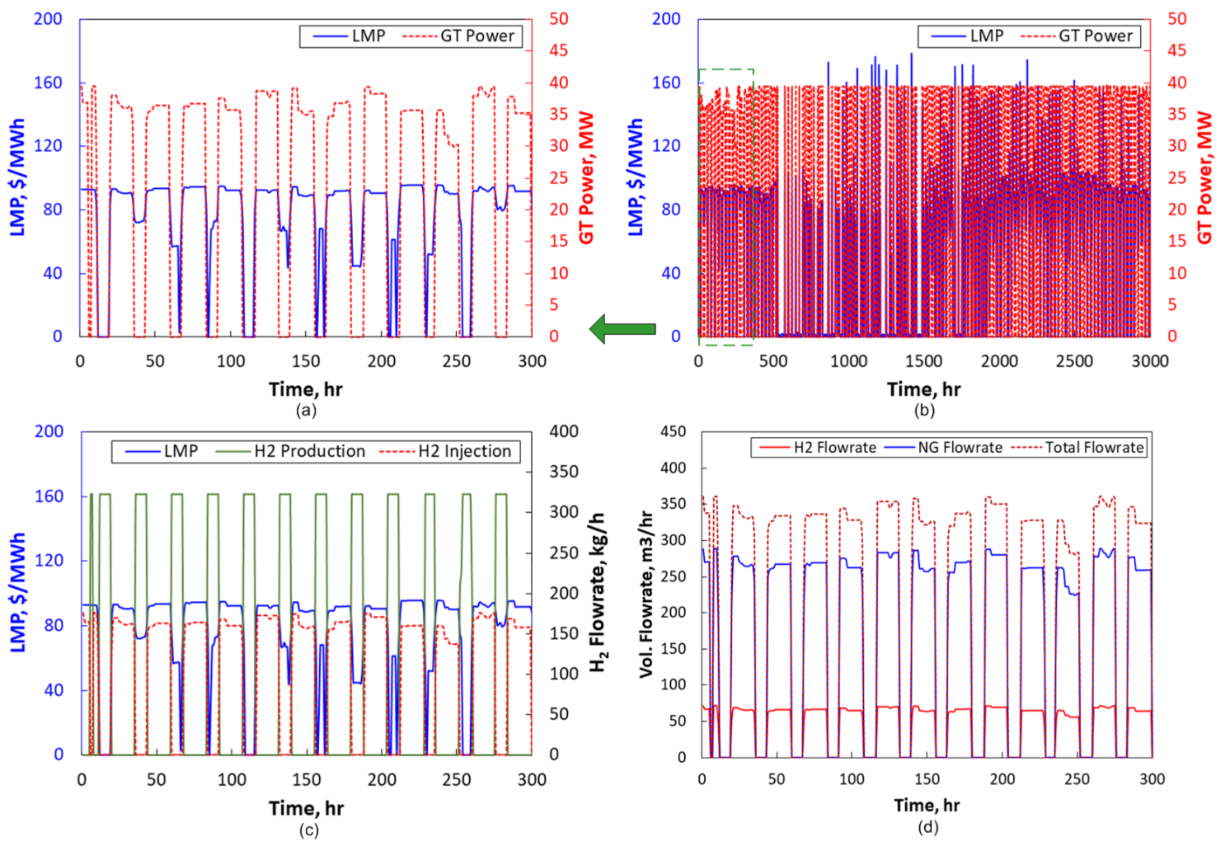

Figure A4. Model profile for case-3.

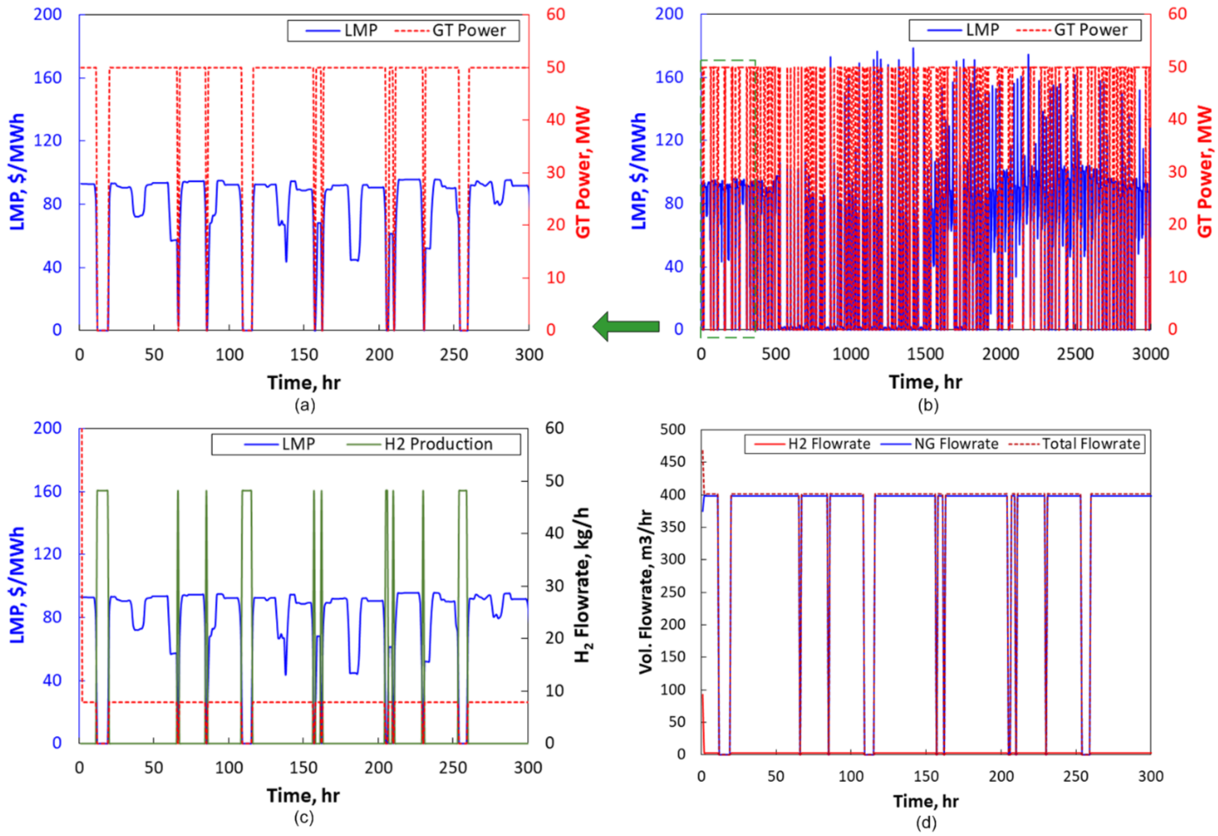

Figure A5. Model profile for case-4.