REPLY COMMENTS OF THE GREEN HYDROGEN COALITION ON THE PROPOSED DECISION AND ALTERNATE PROPOSED DECISION REQUIRING PROCUREMENT TO ADDRESS MID-TERM RELIABILITY (2023-2026)

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June 15, 2021
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In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission (“Commission”), the Green Hydrogen Coalition (“GHC”) hereby submits these reply comments on the Proposed Decision (“PD”) and Alternate Proposed Decision (“APD”) requiring procurement to address mid-term reliability, issued by the Commission on May 21, 2021.

I. THE CURRENT DEFINITION OF GREEN HYDROGEN IS SUITABLE FOR THE ENVISIONED BLENDING APPLICATION IN THE PD/APD AND MAY BE REFINED BY THE LEGISLATURE OR IN FUTURE COMMISSION DECISIONS.

In opening comments, several parties pointed to the ambiguities or uncertainties stemming from the current PD/APD definition of green hydrogen1 while others recommended a narrowing of the definition, such as green hydrogen produced through electrolysis using zero-emissions or RPS-eligible generation.2 GHC acknowledges that defining green hydrogen can be complex and may require narrowing and refinement. Such efforts are currently underway with Senate Bill (“SB”) 18 currently being developed in the Legislature. GHC is hopeful that SB 18 will direct CARB to develop the methodologies to calculate the carbon intensity and help clarify the definition and eligibility criteria in the near term, in time to support procurement activities by the IOUs.

Meanwhile, the PD/APD’s reference to Public Utilities Code 400.2, which defines ‘green electrolytic hydrogen’ as hydrogen produced from grid electricity, is useful and applicable for the blending application envisioned in the PD/APD, as this application would be entirely consistent with the intent of SB 1369 – to use green electrolytic hydrogen as long-duration energy storage. Under the envisioned procurement timeframe, it is unlikely that hydrogen pipelines would be installed and fully operational to supply the green hydrogen to the power plants. The likely near-term practical way of producing the green hydrogen would be to leverage available electric transmission capacity to electrolytically produce and store the green hydrogen at the generating

1 See, e.g., The Utility Reform Network (“TURN”) comments at 6-7 and Environmental Defense Fund (“EDF”) comments at 2, and California Environmental Justice Alliance (“CEJA”), Sierra Club, and Defenders of Wildlife comments at 2.
facility. The stored green electrolytic hydrogen could then be converted back into electricity via the gas turbine. This local production, storage, and dispatch of green hydrogen is no different than how a battery storage solution would similarly use grid electricity for later dispatch to provide reliability. Under this use case, the existing PU Code 400.2 definition of green electrolytic hydrogen is appropriate.

II. **GHC SUPPORTS USE OF DIRECTED GREEN HYDROGEN TO FULFILL BLENDING REQUIREMENTS – PROVIDED THAT ANY SUCH PLANTS LOCATED IN DISADVANTAGED COMMUNITIES HAVE A SPECIFIC PLAN AND COMMITMENT TO ACHIEVE 100% DELIVERED GREEN HYDROGEN BY 2036.**

GHC recognizes that more work needs to be done to define the various commercially viable hydrogen production pathways beyond electrolytic and their emissions impacts, as indicated by TURN’s opening comments. Natural gas pipeline injection, repurposing existing pipelines, and/or building new 100% green hydrogen pipelines will take time. To that end, GHC supports IEP’s recommendation to allow the use of directed green hydrogen similar to how directed biogas is treated today. This strategy will allow for faster market development and aggregation of multi-sectoral demand to justify the needed investment for at scale production and physical deliverability of the green hydrogen molecules.

In opening comments, GHC supported authorizing siting of green hydrogen power plants in disadvantaged communities (DACs) provided that such power plants commit and demonstrate a plan to achieve 100% delivered green hydrogen by 2036. Power plants that operate on 100% hydrogen will have zero CO₂ emissions, zero CO and zero VOCs. However, when combusting hydrogen in the presence of air, some NOx may form. Hydrogen turbine equipment manufacturers are targeting to achieve the same or lower level NOx as today’s requirements for gas fired plants, which includes 2 ppm NOx for combined cycle and 2.5 ppm NOx for simple cycle – each manufacturer has its own proprietary approach for mitigating NOx emissions.

While even these low levels of NOx are not ideal for DACs, GHC believes it is worthwhile to consider implementation of 100% green hydrogen turbines in DACs because they can serve as a beachhead to accelerate at scale green hydrogen supply to displace fossil fuel use in other sectors: namely fossil fuels for light, medium and heavy-duty transport, shipping fuels, industrial applications and even aviation fuels. The additional potential significant emissions reductions from green hydrogen use in these sectors and related economic development benefits that arise from accelerated displacement of fossil fuels for these other applications supports authorization of 100% hydrogen turbines in DACs.

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3 TURN comments at 6-7.
III. **MULTIPLE PARTIES MISCONSTRUE THE VALUE OF GREEN HYDROGEN BY COMPARING IT TO NATURAL GAS ON A 1:1 BASIS.**

In opening comments, several parties suggested that green hydrogen blending is too costly as compared to the costs of natural gas, with Calpine suggesting that at $2/kg, the heat content available in green hydrogen would equate to approximately $15/MMBtu, which is approximately $11/MMBtu above the current natural gas prices.\(^4\) GHC does not argue with these cost estimates – rather, GHC believes that Calpine and other parties that equate green hydrogen to natural gas as a 1:1 replacement are approaching the cost effectiveness of green hydrogen with an inadequate framework. Green hydrogen is a type of gaseous fuel that can displace natural gas. However, it is also an intermediary which can effectively indefinitely store electricity for later use/dispatch to address peak reliability needs with zero greenhouse gas emissions. In this regard, and as stated above in Section II, the green hydrogen use case for 2023-2026 reliability and beyond is bulk energy storage, either via green (electrolytically produced) hydrogen stored locally in about ground pressured containers or in a pipeline. The cost-effectiveness of green hydrogen for gas turbine use is best evaluated under a storage framework and compared to other storage alternatives.

In this regard, the production and use of green electrolytic hydrogen as energy storage should also factor in all potential benefits which includes not only capacity, but also valuable ancillary services such as voltage support, spin/non spinning reserve and frequency regulation. These services can be provided by modulating the electrolysis resource as a modifyable load. California has led the world in the use of energy storage, primarily battery storage, to help balance and maintain and affordable and reliable grid. As intermittent renewables penetration increases, so will the need for longer duration storage. The June 2020 E3 study, *Hydrogen Opportunities in a Low-Carbon Future*, concluded that batteries are ideal for short duration, intra-day storage applications and hydrogen is ideal for long duration, multi-day storage.\(^5\)

From a longer duration perspective, storing energy via green hydrogen is the only commercially viable pathway to achieve seasonal balancing and matching of renewable energy supply with demand. This cannot happen overnight, and the only reasonable pathway forward to achieving seasonal renewable storage is by increasing the amount of hydrogen that used by the power sector over time. GHC applauds the PD and the APD for recognizing both the need for long duration seasonal balancing as well as the need to get started in a practical way by encouraging blending with fossil generation.

Today, solar and wind energy are the lowest cost, most abundant sources of marginal energy – and, they are theoretically unlimited in supply and emission-free. As these intermittent renewables increase their penetration, so does curtailment because of the mismatch between generation and demand. In March 2021, California’s wind and solar curtailments hit a record high

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\(^4\) Calpine comments at 3-4.

of nearly 350,000 MWHs. Green hydrogen has the ability to harness this abundant renewable resource for later use in the power sector (even a different season), and to concurrently harness this abundant energy source to displace fossil fuels in other sectors.

For the power sector, the highest value mass-scale application is to supply peak capacity and ensure reliability using existing gas turbine, electric transmission and natural gas pipeline infrastructure. The recently launched HyDeal LA initiative is demonstrating that $1.50/kg delivered to the LA basin is possible, with high level findings scheduled to be released in August 2021. Low cost green hydrogen used as bulk energy storage for low cost renewables provides a viable value proposition for the electric sector by providing needed renewable energy dispatchability and reliability. Below is a simplified value proposition using costs from Intermountain Power Project (IPP), the 840 MW CCGT that is being deployed in Delta Utah; which demonstrates that using dispatchable green hydrogen turbine generation for 25% of the capacity need blended with low-cost renewable PPAs for the remaining 75% of the need can achieve costs for 100% reliable, renewable electricity that are on par with today’s wholesale electricity prices. In summary, when appropriately evaluated as a peaking solution, the use of green hydrogen in gas turbines can enable 100% renewable energy at competitive costs with today’s wholesale electricity prices.

<table>
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<th>Explanation</th>
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<th>2035</th>
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1. Capacity Factor based on generic CC plant from modelling performed for CEC 1366 Requirements;
2. Heat rate based on levelized heat rate of advanced class units;
3. CC Unit costs based on minimum costs for O&M of equipment, based on utility grade requirements (O&M, financing, excludes fuel);
4. GHG Costs are provided as a floating variable. Reference EIR Reports for cost projections;
5. Hydrogen commodity cost is based on projections from DOE based on technology development;
6. Hydrogen levitized costs at hydrogen generation based on green hydrogen including storage and transportation, and CCGT equipment modifications required;
7. Solar wind /M Wh costs may fluctuate with market price. Sourced from Pacificorp’s tariffs. Seeing rates currently at $5/MWh.

IV. SEVERAL PARTIES ERR IN ASSERTING THAT GREEN HYDROGEN IS NOT COMMERCIALLY AVAILABLE TODAY. THIS IS INCORRECT.

GHC disagrees with several parties who contended that green hydrogen is not a viable midterm reliability procurement option due to technology nascentcy, costs, timeline to commercial online dates, and/or GHG impact commensurate with blending requirements, where alternatives...

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<sup>6</sup> CAISO Managing Oversupply. Data compiled April 2021. [http://www.caiso.com/informed/Pages/ManagingOversupply.aspx#dailyCurtailment](http://www.caiso.com/informed/Pages/ManagingOversupply.aspx#dailyCurtailment)
should be allowed (e.g., RNG, blue hydrogen, CCS) for fossil capacity procurement or lower blending requirements. The viability or feasibility of green hydrogen projects is not speculative or theoretical; hydrogen production and blending projects are occurring today all across Europe and landed a significant milestone in North America with the Intermountain Power Agency’s issuance of a purchase order to Mitsubishi to transition the Intermountain Power Project in Utah from an 1800 MW coal fueled generator to an 840 MW combined cycle hydrogen gas turbine that is capable of utilizing a 30% blend (by volume) on day 1. This new hydrogen turbine will be commissioned the summer of 2025, and the portion of green hydrogen will be gradually increased to 100% over time, completely phasing out natural gas. IPP is one of four contracted hydrogen gas turbines by Mitsubishi in North America today. Work is also already rapidly underway on the HyDeal LA Initiative, which is architecting system plan for converting four in-basin generating facilities to 100% green hydrogen fueled turbines. These initiatives highlight how green hydrogen production and use in gas turbines viable now. Early findings from HyDeal LA phase 1 effort are indicating that the publicly stated goal to achieve $1.50/kg delivered green hydrogen to aggregated multi-sectoral off-takers at scale (>1 million metric tons demand/year) in the Los Angeles Basin by 2030 is achievable with appropriate infrastructure investments. With a timely procurement authorization and directive for green hydrogen in select thermal generation assets, the Commission has the opportunity to build on these very large project opportunities to accelerate the realization of the green hydrogen economy for California and benefit from incrementally clean and reliable capacity at the same time.

Furthermore, doubts about the feasibility or stringency of 30% or higher fuel blending requirements are not founded given the available technologies today. According to Mitsubishi Power, a leading vendor of gas turbine technology, such technologies have already been validated to support 30% to 100% blends of hydrogen by volume. Rather than awaiting further study or pilots, a strong and unambiguous procurement signal is needed today, as done in the PD/APD. The competitive solicitations will reveal the viability and feasibility of these technologies.

V. CONCLUSION.

GHC appreciates the opportunity to submit these reply comments on the PD and the APD and looks forward to working with the Commission and stakeholders in this proceeding.

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7 See, e.g., Pacific Gas and Electric Company (“PG&E”) comments at 12, Calpine comments at 3-4, Independent Energy Producers Association (“IEP”) comments at 10 and 13, Middle River Power (“MRP”) comments at 11-12, and Diamond Generating Corporation (“DGC”) comments at 2-3.

8 See GHC’s Green Hydrogen Guidebook at: https://www.ghcoalition.org/guidebook

9 See https://www.ghcoalition.org/green-hydrogen-at-scale

10 Mitsubishi Power currently offers 2 types of combustors catering to individual project requirements and hydrogen densities. Both diffusion and pre-mix (DLN) types are ready and available to achieve up to 100% and 30% H2 density by volume, respectively. In development is the mult-cluster type, which is anticipated to achieve 100% by 2025.
Respectfully submitted,

/s/ Janice Lin
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Date: June 15, 2021