SOUTHERN CALIFORNIA GAS COMPANY (SOCALGAS)
SIERRA CLUB DATA REQUEST 4 (SIERRA CLUB DR-04)
AMENDED HYDROGEN BLENDING DEMONSTRATION APPLICATION (A.22-09-006)

DATE REQUESTED: MARCH 29, 2024
DATE SUBMITTED: APRIL 16, 2024

I. GENERAL OBJECTIONS

1. SoCalGas objects generally to each request to the extent that it seeks information protected by the attorney-client privilege, the attorney work product doctrine, or any other applicable privilege or evidentiary doctrine. No information protected by such privileges will be knowingly disclosed.

2. SoCalGas objects generally to each request that is overly broad and unduly burdensome. As part of this objection, SoCalGas objects to discovery requests that seek "all documents," "all emails," or "all information" and similarly worded requests on the grounds that such requests are unreasonably cumulative and duplicative, fail to identify with specificity the information or material sought, and create an unreasonable burden compared to the likelihood of such requests leading to the discovery of admissible evidence. Notwithstanding this objection, SoCalGas will produce all relevant, non-privileged information not otherwise objected to that it is able to locate after reasonable inquiry.

3. SoCalGas objects generally to each request to the extent that the request is vague, unintelligible, or fails to identify with sufficient particularity the information or documents requested and, thus, is not susceptible to response at this time.

4. SoCalGas objects generally to each request that: (1) asks for a legal conclusion to be drawn or legal research to be conducted on the grounds that such requests are not designed to elicit facts and, thus, violate the principles underlying discovery; (2) requires SoCalGas to do legal research or perform additional analyses to respond to the request; or (3) seeks access to counsel's legal research, analyses or theories.

5. SoCalGas objects generally to each request to the extent it seeks information or documents that are not reasonably calculated to lead to the discovery of admissible evidence.

6. SoCalGas objects generally to each request to the extent that it is unreasonably duplicative or cumulative of other requests.

7. SoCalGas objects generally to each request to the extent that it would require SoCalGas to search its files for matters of public record such as filings, testimony, transcripts, decisions, orders, reports or other information, whether available in the public domain or through FERC or CPUC sources.

8. SoCalGas objects generally to each request to the extent that it seeks information or documents that are not in the possession, custody or control of SoCalGas.

9. SoCalGas objects generally to each request to the extent that the request would impose an undue burden on SoCalGas by requiring it to perform studies, analyses or calculations or to create documents that do not currently exist.

10. SoCalGas objects generally to each request that calls for information that contains trade secrets, is privileged or otherwise entitled to confidential protection by reference to statutory protection. SoCalGas objects to providing such information to the extent it is not covered by the parties' Non-Disclosure Agreement.

II. EXPRESS RESERVATIONS

1. No response, objection, limitation or lack thereof, set forth in these responses and objections shall be deemed an admission or representation by SoCalGas as to the existence or nonexistence of the requested information or that any such information is relevant or admissible.

2. SoCalGas reserves the right to modify or supplement its responses and objections to each request, and the provision of any information pursuant to any request is not a waiver of that right.

3. SoCalGas reserves the right to rely, at any time, upon subsequently discovered information.

4. These responses are made solely for the purpose of this proceeding and for no other purpose.

III. RESPONSES

QUESTION 1

Please provide all schematics of the production and blending equipment planned for both the Closed System Project and the Open System Project.

RESPONSE 1

SoCalGas objects to this request on the grounds that it is vague and ambiguous, particularly with respect to the term "schematics." Subject to and without waiving the foregoing objection, SoCalGas responds as follows:

All currently available preliminary design figures of the production and blending equipment planned for both the Closed System Project and Open System Project were provided in Figures 1-3 in Chapters 1 and 2, respectively, of the Joint Utilities' prepared testimony. Please note that these are preliminary design figures, which will involve further engineering design to finalize. Thus, specific production and blending schematics have not been developed, as equipment selection has not been finalized.

QUESTION 2

Please refer to Chapter 1 of the Joint Utilities' prepared direct testimony, page 1, lines 24-26: "The purpose of this Closed System Project is to demonstrate operational, live blending and collect system performance data for blending from 5% to 20% hydrogen gas by volume in an isolated portion of a medium pressure steel and plastic distribution pipeline system." (Footnote omitted.)

a. What year was the portion of the distribution system SoCalGas intends to use for this pilot constructed?

b. Please identify all types of steel alloys and plastic materials in the portion of the distribution system SoCalGas intends to isolate for this pilot project.

c. Please provide a list of all types of steel alloys and plastic materials used throughout SoCalGas' medium and low pressure distribution system.

d. Please provide all analysis SoCalGas has performed of whether the materials used in the portion of the distribution system in the intended pilot site are representative of the materials and vintages throughout SoCalGas' medium and low pressure distribution system.

RESPONSE 2

a. The pipeline in the existing distribution system SoCalGas intends to use for its demonstration project was constructed in 1999.

b. The Closed System Project will use newly installed Carbon Steel. Specific pipeline steel grade will be selected in subsequent detailed engineering design phases. The type of plastic material currently installed in the portion of the distribution system that will be isolated and used in this demonstration is medium density polyethylene (MDPE).

c. Throughout its medium pressure distribution system, SoCalGas's materials include Carbon Steel pipelines with various API grades and MDPE pipelines with various resin types. Small traces of legacy Stainless-Steel pipelines may still exist, however, are replaced when found. SoCalGas does not have lines classified as low pressure distribution.

d. SoCalGas operates Carbon Steel and MDPE across its medium pressure distribution system. SoCalGas is proposing to utilize Carbon Steel and MDPE in its Closed System Project. Therefore, the materials proposed in SoCalGas's Closed System Project are representative of the materials present in SoCalGas medium pressure distribution system.

QUESTION 3

Please refer to Chapter 1 of the Joint Utilities' prepared direct testimony, page 2, lines 19-21: "The Closed System Project will provide validation on a local system of a strong base of previous analysis, testing, and field demonstrations including comparable field testing performed in the United Kingdom," citing a website for the UK's HyDeploy pilot.

a. Please provide all reports, results, analysis, air quality monitoring data, and other documents related to the HyDeploy pilot that SoCalGas considered in its development of this application.

b. Please identify all information that SoCalGas intends to generate through this pilot that was not developed in the HyDeploy pilot.

c. Please explain how SoCalGas' proposals in this application avoid duplication with the HyDeploy pilot.

RESPONSE 3

a. SoCalGas objects on the ground that the request seeks information that is equally available to Sierra Club through public sources. Without waiving and subject to these objections, SoCalGas responds as follows:

   Documents reviewed are publicly available on the HyDeploy website.[1]

b. SoCalGas objects to this request as overly broad, unduly burdensome and oppressive, particularly with respect to the phrase "all information." SoCalGas further objects to this request on the ground that it calls for speculation regarding "all information" that was not developed in the HyDeploy project. Without waiving and subject to these objections, SoCalGas responds as follows:

   SoCalGas intends to generate California- and SoCalGas-specific data through its proposed demonstration projects, which was not developed in the HyDeploy pilot, including, but not limited to, various parameters and differences that are outlined in Response 3.c below.

c. SoCalGas objects on the ground that the request seeks information that is equally available to Sierra Club through public sources, including HyDeploy's website. Without waiving and subject to these objections, SoCalGas responds as follows:

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[1] HyDeploy, *Pioneering the safe use of blended hydrogen in gas networks to reduce carbon emissions*, available at: https://hydeploy.co.uk/.

SoCalGas's proposals in the Amended Application are for blending hydrogen up to 20% in California's and SoCalGas's specific pipeline system rather than on pipeline systems located in the United Kingdom and at Keele University. Not all operational parameters of the HyDeploy project are known, as SoCalGas has only evaluated publicly available data. Thus, SoCalGas's demonstrations provide an opportunity to identify operation and emergency response enhancements for blending hydrogen into SoCalGas's specific infrastructure, which may include, but is not limited to, emergency response procedures, training procedures for utility workforce, operational procedures for SoCalGas, and maintenance procedures. Additionally, climate and terrain in the United Kingdom is different from that of SoCalGas's territory, which can affect operational characteristics of natural gas use and, thus, potential differences in operations with hydrogen blends. In tandem, there is an opportunity to provide workforce experience to SoCalGas employees for handling hydrogen blends.

In addition to operational parameters, there may be additional differences in data produced from the HyDeploy pilot in compared to SoCalGas's proposed projects:

- Materials: As outlined in Response 2.c, SoCalGas will utilize Carbon Steel, and MDPE pipeline materials in its Closed System Project. As noted in the HyDeploy Project Close Down Report (HyDeploy Report), "The Keele University network consisted of both medium and low pressure pipework with; 4,381 meters of [MDPE] across both pressure tiers and 100 meters of medium pressure steel pipework, all services to users were either MDPE or steel."[2] The types of steel pipelines and MDPE resins were not specified in the HyDeploy Report and are unknown by SoCalGas. Therefore, there is a need to evaluate California- and SoCalGas-specific materials.
- Odorant: SoCalGas may use different odorant formulations/blends compared to the United Kingdom. Odorant chemical makeups were not disclosed in the HyDeploy Report. Therefore, SoCalGas needs to conduct its own intensity testing to verify the concentration of odorant in natural gas before blending with unodorized hydrogen.
- End-Use Equipment: California emissions testing protocols/standards may differ from those used in the HyDeploy project. Generally, California's emissions testing protocols are developed alongside California's various Air Quality Management Districts, many of which reference applicable

[2] HyDeploy Project, Project Close Down Report – Revision 03 (June 2021) at 11. Available at: https://hydeploy.co.uk/app/uploads/2022/06/HyDeploy-Close-Down-Report_Final.pdf.

American test methods, such as those outlined by the American National Standards Institute (ANSI).

- Leak detection devices: SoCalGas will be utilizing its approved leak detection technologies which may differ from those used in the HyDeploy project. Additionally, SoCalGas will strive to incorporate newer technologies available on the market that are compatible with hydrogen, where feasible.
- Metering: The HyDeploy Report does not disclose specific meter technology utilized. Thus, SoCalGas intends to evaluate SoCalGas specific meter technologies.

QUESTION 4

Please refer to Chapter 1 of the Joint Utilities' prepared direct testimony, page 2, lines 19-21: "The Closed System Project will provide validation on a local system of a strong base of previous analysis, testing, and field demonstrations including comparable field testing performed . . . on the UC Irvine campus."

a. Please provide all reports, results, analysis, air quality monitoring data, and other documents related to the prior UC Irvine project.

b. Please identify all information that SoCalGas intends to generate through this pilot that was not developed in the prior UC Irvine project.

c. Please explain how SoCalGas' proposals in this application avoid duplication with the prior UC Irvine project.

d. Please identify the total cost of the prior UC Irvine project and its funding sources. Please specifically identify how much funding was recovered from SoCalGas ratepayers, through what mechanisms, and the Commission decisions authorizing that rate recovery.

e. Please identify the percentage of hydrogen blending achieved in the prior UC Irvine project.

f. Please provide an inventory of all equipment that used the hydrogen blend in the prior UC Irvine project. For each piece of equipment, please identify any modifications performed on the equipment as part of the project.

g. Please identify the air quality monitoring protocols used in the prior UC Irvine project.

RESPONSE 4

SoCalGas generally objects to this request on the grounds that it is vague and ambiguous, and overly broad, particularly with respect to the phrase "the prior UC Irvine project." For purposes of this response, SoCalGas presumes that the "prior UC Irvine project" referenced in every subpart of this question is the 2016 renewable hydrogen referred to in footnote 9 of Chapter 1 of the Joint Utilities' prepared direct testimony.[3]

[3] UCI News, In a national first, UCI injects renewable hydrogen into campus power supply (December 6, 2016), available at: https://news.uci.edu/2016/12/06/in-a-national-first-uci-injectsrenewable-hydrogen-into-campus-power-supply/.

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a. SoCalGas objects to this request pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure on the grounds that it seeks the production of information that is neither relevant to the subject matter involved in the pending proceeding nor is likely reasonably calculated to lead to the discovery of admissible evidence. SoCalGas further objects to this request on the grounds that it is vague and ambiguous, and overly broad, particularly with respect to the phrase "related to." Subject to and without waiving the foregoing objections, SoCalGas responds as follows:

   The "Power-to-Gas Demonstration: Dynamic Operation and Hydrogen Injection Impacts" (P2G Report) is provided as Attachment 4.a.

b. SoCalGas objects to this request pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure on the grounds that it seeks the production of information that is neither relevant to the subject matter involved in the pending proceeding nor is likely reasonably calculated to lead to the discovery of admissible evidence. SoCalGas further objects to this request on the grounds that it is vague and ambiguous, and overly broad, particularly with respect to the phrase "related to." Subject to and without waiving the foregoing objections, SoCalGas responds as follows:

   The focus of the Power-to-Gas (P2G) project was to successfully demonstrate P2G technology and to test blending of hydrogen into UC Irvine's combustion turbine technology. All blending was performed in UC Irvine's houseline on its campus that ultimately feeds its combustion turbine. SoCalGas's demonstration is intended to demonstrate blending on live, operational utility distribution pipeline systems, rather than a university houseline. While emissions impacts of turbine technology were evaluated in the P2G demonstration, blending was only performed up to 3.4% hydrogen by volume. SoCalGas intends to demonstrate hydrogen blending in light commercial equipment and test for emissions up to 20% hydrogen by volume. As outlined in Response 3, SoCalGas's demonstration will also look to gain workforce experience as well as validate leak detection technologies utilized by utility personnel that was not performed in other demonstrations.

c. SoCalGas objects to this request pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure on the grounds that it seeks the production of information that is neither relevant to the subject matter involved in the pending proceeding nor is likely reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving the foregoing objections, SoCalGas responds as follows:

Please see Response 4.b. SoCalGas's proposed demonstration project aims to evaluate blending on live, operational utility distribution pipelines, rather than testing the feasibility of P2G technology and blending into university houseline. While the P2G project demonstrates a base case for successful blending, the focus of the project was not to inform data on live, operational utility distribution pipelines.

d. SoCalGas objects to this request because it seeks public information that is equally available to Sierra Club. Without waiving and subject to this objection, SoCalGas responds as follows: The total cost of the P2G project was $1.5 million and was funded through SoCalGas's Research Development and Demonstration (RD&D) program. SoCalGas's RD&D funds are collected from ratepayers through a one-way balancing account authorized in the General Rate Case (GRC). The project was reported in SoCalGas's 2019 RD&D Annual Report.[4]

e. The P2G project blended up to 3.4% hydrogen by volume. Please refer to the P2G Report (Attachment 4.a) for more information.

f. SoCalGas objects to this request as vague and ambiguous, particularly with respect to the phrase "all equipment that used the hydrogen blend." Without waiving and subject to this objection, SoCalGas responds as follows:

   Please refer to the P2G Report. SoCalGas interprets this question as referring to end-use equipment that received the hydrogen blended gas. Equipment utilized was UC Irvine's combustion turbine. SoCalGas is not aware of any modifications made to the turbine.

g. Please refer to the P2G Report for air quality monitoring protocols.

[4] SoCalGas, "2019 Annual Report Fostering Breakthrough Innovation Research, Development, And Demonstration Program", *available at*: https://www.socalgas.com/sites/default/files/2021-10/2019-SoCalGas-RDD-Annual-Report.pdf#page=[43].

QUESTION 5

Please refer to Chapter 1 of the Joint Utilities' prepared direct testimony, page 3, lines 21-23: "The hydrogen blend will be used for light commercial equipment, such as boilers, water heaters, and cooking equipment."

a. Please provide a full inventory of the equipment that will operate on a hydrogen blend, including the make, model, function, location, and age of each piece of equipment.

b. Please identify any equipment that will use a hydrogen blend that SoCalGas considers difficult-to-decarbonize.

RESPONSE 5

a. SoCalGas has not conducted a full inventory of end-use equipment onsite. SoCalGas has worked with UC Irvine to identify equipment types included in the hydrogen blending demonstration, as laid out in Chapter 1, p. 3 of the Joint Utilities' prepared direct testimony.

b. SoCalGas objects to this request pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure on the grounds that it seeks the production of information that is neither relevant to the subject matter involved in the pending proceeding nor is likely reasonably calculated to lead to the discovery of admissible evidence. SoCalGas further objects to this request on the grounds that it is vague and ambiguous, particularly with respect to the phrase "difficult-to-decarbonize," which SoCalGas did not use in the Amended Application. SoCalGas also objects to this request because it misconstrues SoCalGas's testimony.

QUESTION 6

Please refer to Chapter 1 of the Joint Utilities' prepared direct testimony, page 8, lines 28-30: "The electrolyzer will use electricity from solar installed at the site along with UC Irvine's campus microgrid . . ."

a. Under what circumstances would the electrolyzer use electricity from UC Irvine's campus microgrid as opposed to the dedicated solar array installed for the project?

b. To the extent that campus microgrid electricity is used to power the electrolyzer, how does SoCalGas plan to ensure it meets the Commission's requirement to use hydrogen that "does not use fossil fuel as either a feedstock or production energy source" (D.22-12-057, p. 48)?

c. Has SoCalGas calculated the carbon intensity of the hydrogen it intends to produce for this project? If yes, please provide those calculations and identify all underlying assumptions and the basis for those assumptions.

RESPONSE 6

a. As indicated in Chapter 1, p. 8, the electrolyzer will use electricity from solar installed at the site along with UC Irvine's campus microgrid and local municipal water to create hydrogen and store it onsite. Preliminary calculations indicate, on average, the solar array will meet the power requirement for running the electrolyzer. Unforeseen circumstances, such as but not limited to, unusual weather or unusually high natural gas demand may result in the project relying on the campus' microgrid more than calculated to support hydrogen generation. SoCalGas strived to size the proposed solar production to match the electrical demands of the electrolyzer and plans to fully utilize the available space for the solar footprint at the project site (i.e., the campus police parking lot).

b. SoCalGas plans for the electrolyzer to be powered by the solar array, as indicated in Response 6.a. In the event that the power requirements exceed that provided by the solar array, SoCalGas will work with UC Irvine to determine if any available non-fossil fuel resources on the campus microgrid can be prioritized toward the hydrogen production loads.

c. No. However, SoCalGas expects the carbon intensity of the hydrogen produced to be near-zero as preliminary calculations indicate, on average, the solar array will meet the power requirement for running the electrolyzer.

QUESTION 7

Chapter 1 of the Joint Utilities' testimony, page 9, lines 12-13 state that "the majority of the electricity required for operation of the electrolyzer, associated equipment, and hydrogen production" will come from an on-site solar array. What specific portion of the electricity will come from the on-site solar array? What will be source of the remainder of the electricity?

RESPONSE 7

As noted in Response 6, SoCalGas intends to tie into UC Irvine's microgrid and, thus, any excess electricity needs beyond those supplied by the solar array are slated to come from UC Irvine's microgrid. Power usage of the site is dependent on multiple conditions including weather, hydrogen storage, natural gas usage, and hydrogen blend percentage. As estimated, the electrolyzer power requirements will come from the onsite solar array, barring unforeseen circumstances, as outlined in Response 6.

QUESTION 8

Chapter 1 of the Joint Utilities' testimony, page 11, lines 5-7 state that "all customer appliances involved in the demonstration on UC Irvine's campus will be offered courtesy inspections to confirm the appliances are in safe working order." On page 16, Mr. Waymire states that safety efforts for the project include "survey[ing] end-use customer equipment to confirm behind-the-meter equipment present is free of leakage and is operational."

a. Will SoCalGas require passing inspections of all end use customer equipment that will receive the hydrogen blend prior to commencement of blending?

b. Will SoCalGas' inspections screen for operational issues other than leaks?

c. Does SoCalGas plan to track and/or report modifications or repairs made to end use equipment pursuant to these inspections?

RESPONSE 8

a. SoCalGas objects to this request on the grounds that it is vague and ambiguous, particularly with respect to the phrase "require passing inspections." Subject to and without waiving the foregoing objection, SoCalGas responds as follows:

   As indicated in Chapter 1, Table 3, SoCalGas will offer and perform end-use equipment evaluations to confirm the equipment is working properly, prior to the commencement of hydrogen blending.

b. Please refer to Exhibit 1A, SoCalGas's Preliminary Data Collection Plan, of Chapter 1 testimony. SoCalGas will screen for operational issues other than leakage.

c. SoCalGas objects to this request on the grounds that it is vague and ambiguous, particularly with respect to the phrase "modifications or repairs made to end use equipment." Subject to and without waiving the foregoing objection, SoCalGas responds as follows:

   SoCalGas intends to track equipment modifications and repairs, although they are not anticipated.

QUESTION 9

Chapter 1 of the Joint Utilities' prepared testimony, page 16, lines 23-24 identify "continuous remote monitoring of hydrogen production, storage, and blending areas" as a safety measure planned for inclusion in the Closed System Project. Please list all equipment that SoCalGas plans to use for continuous remote monitoring of the hydrogen production, storage, and blending areas.

RESPONSE 9

SoCalGas will select the technologies and models for the equipment to be installed onsite during detailed design with input from an independent third-party. The project will use proven technologies to promote accuracy and safety.

QUESTION 10

Chapter 1 of the Joint Utilities' prepared testimony, page 16, lines 25-26 identify "automatic and remote shutdown capabilities for the hydrogen production and blending facility in the case an alarm is triggered or a leak is detected" as a safety measure planned for inclusion in the Closed System Project. Will automatic and remote shutdown capabilities also be triggered by (i) leakage detected along the pipelines carrying the blended gas and/or (ii) leakage from end-use equipment receiving the blended gas?

RESPONSE 10

Automatic and remote shutdown capabilities for alarms or leak detection beyond the hydrogen production and blending facility have not yet been determined and will be evaluated during the detailed engineering design phases with input from an independent third-party. Please refer to Exhibit 1A, SoCalGas's Preliminary Data Collection Plan, of Chapter 1 of the Joint Utilities' prepared testimony. SoCalGas intends to evaluate the feasibility of various leak survey technologies for its Closed System Project. As leak detection technologies are considered, SoCalGas will evaluate whether these technologies can trigger automatic and remote shutdown from (i) leakage detected along the pipelines carrying the blended gas and/or (ii) leakage from end-use equipment receiving the blended gas. In any case, if a leak is detected, either on the pipeline system or from end-use equipment, a technician will be dispatched to respond to the notification, regardless of automatic or remote shutdown capabilities.

QUESTION 11

Chapter 1 of the Joint Utilities' prepared testimony, page 17, lines 13-15 state "there is still a need to conduct a California-specific hydrogen blending demonstration due to potentially different designs in pipeline systems and end-use equipment." Please identify all potential differences in designs in the pipeline systems and end-use equipment in the HyDeploy pilot and SoCalGas' system and end-user equipment that SoCalGas is aware of.

RESPONSE 11

SoCalGas objects on the ground that the request calls for speculation regarding "all potential differences in designs in the pipeline systems and end-use equipment in the HyDeploy pilot and SoCalGas' system and end-user equipment." Without waiving and subject to this objection, SoCalGas responds as follows:

As outlined in Response 3.c, there are various California and utility specific items that SoCalGas proposes to collect data on that are not duplicative of the HyDeploy pilot. These areas include, but are not limited to, potential operational differences, potential difference in pipeline materials, potential difference in odorant, potential metering differences, utility specific leak detection technologies, and differences in emissions testing for end-use equipment. As discussed in Chapter 1, p. 17 of the Joint Utilities' prepared direct testimony, while SoCalGas and other stakeholders can learn from the successful HyDeploy trial, there is still a need to conduct California-specific hydrogen blending demonstrations.

QUESTION 12

Page 17, footnote 18, of Chapter 1 of the Joint Utilities' prepared testimony states that in contrast to North American appliances, United Kingdom "gas appliances manufactured after 1996 have been designed to operate with hydrogen blends up to 23%." Please explain how this requirement has affected the design of appliances for the UK market. Has SoCalGas investigated whether there are products sold in North America that are not available in the UK market because they fail to meet this requirement? If yes, please provide all documents related to this investigation.

RESPONSE 12

SoCalGas objects to this request pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure on the grounds that it seeks the production of information that is neither relevant to the subject matter involved in the pending proceeding nor is likely reasonably calculated to lead to the discovery of admissible evidence. SoCalGas further objects to this request on the ground that it calls for speculation regarding "how this requirement has affected the design of appliances for the UK market."

QUESTION 13

Chapter 1 of the Joint Utilities' prepared testimony, page 19, lines 1-3 state that "SoCalGas will work with the local community to identify relevant community-based organizations (CBO) for project engagement." Please list all CBOs that SoCalGas is considering for collaboration on the Closed System project.

RESPONSE 13

SoCalGas has not yet identified specific community-based organizations (CBOs) to engage on this project. However, SoCalGas will collaborate with UC Irvine to identify relevant CBOs for project engagement once campus led committees (administrative and student advisory) are formed.

QUESTION 14

Chapter 1 of the Joint Utilities' prepared testimony, page 19, states that "SoCalGas will perform enhanced leak detection protocols to verify that the introduction of hydrogen is not compromising the safety of the gas system and associated end-use equipment throughout the duration of the demonstration." Please explain what equipment and procedures comprise "enhanced leak detection protocols" and where on the system they take place.

RESPONSE 14

When referencing "enhanced leak detection protocols", SoCalGas means leak detection protocols that are increased in frequency. As outlined in Chapter 1, Section II.C.2 of the Joint Utilities' prepared testimony, SoCalGas will perform leak surveys on the pipeline system and customer equipment on a monthly basis. This is an increase beyond the current leak surveys performed on the distribution pipeline system and well beyond the courtesy checks performed for customer equipment upon customer requests. Continuous and remote leak detection will be performed on the hydrogen production, blending, and storage areas. Specific leak detection equipment selection will be finalized at a later date and in collaboration with an independent third-party pursuant to Commission Decision (D.) 22-12-057, Ordering Paragraph (OP) 7l.

QUESTION 15

Exhibit 1A to Chapter 1 of the Joint Utilities' prepared testimony states: "For both closed and open system projects, SoCalGas will perform emissions testing (CO2, NOx, CO, and O2) per South Coast Air Quality Management District (SCAQMD) and San Joaquin Valley Air Pollution Control District (APCD) test methods to determine the appliance performance and combustion efficiency."

a. Please identify the specific test methods SoCalGas is referring to and the specific SCQAMD rules and San Joaquin Valley APCD rules referred to in Table 2 of the exhibit.

b. Please identify where SoCalGas intends to locate air quality monitors used to monitor end-use emissions in both the open system and closed system pilots.

RESPONSE 15

a. Specific test methods for monitoring emissions have not yet been determined and will be developed in collaboration with an independent third-party pursuant to OP 7l of D.22-12-057. SoCalGas intends to align testing methodologies and associated results for the end-use equipment with rules from the respective air quality management jurisdiction where each project is located (i.e., SCAQMD for the Closed System Project and San Joaquin Valley APCD for the Open System Project).

b. SoCalGas has not designated where air quality monitors will be located for each project at this time. SoCalGas will work with UC Irvine, participating customers in the Open System Project, and any designated third parties involved in the data collection process to determine appropriate air quality monitor locations.

QUESTION 16

Page 20 of the Joint Utilities' Amended Application states, with regard to Sierra Club's feedback letter following the technical workshop, that "suggestions in the letter were reviewed, and in some cases, adopted." Please identify the suggestions that were adopted. Please also identify the suggestions from Sierra Club's letter that were not adopted and explain why SoCalGas did not adopt each suggestion.

RESPONSE 16

SoCalGas addressed the following items in each section of "Sierra Club Comments on November 6, 2023 Joint Utilities Hydrogen Blending Technical Workshop," referred hereto as the Sierra Club Letter, as categorized below:

Engagement

The Sierra Club Letter expresses concerns about the adequacy of the utilities' stakeholder and public engagement process. SoCalGas has been actively engaging with both the UC Irvine community and the City of Orange Cove leading up to the application filing, as outlined in the Stakeholder Engagement Plan sections of Chapters 1 and 2, respectively. SoCalGas will continue to engage with the communities involved and relevant stakeholders to communicate project updates and take feedback into account. Further, SoCalGas will work with a dedicated administrative team, including experts from Facilities Management and Environmental Health & Safety, as well as a student advisory committee at UC Irvine.[5] With robust stakeholder engagement plans in place to adequately inform and consult communities on project details as recommended in the Sierra Club Letter and outlined in SoCalGas's testimony, SoCalGas did not have any further recommendations to adopt with regard to engagement.

Public Health

The Sierra Club Letter proposed two main items with regard to public health: 1) the utilities must inform affected customers of the risks and measured impacts of the blending projects both before and throughout the pilot periods, and 2) SoCalGas should employ continuous monitoring systems for increased emissions, such as NOx emissions, resulting from combustion of the hydrogen blend.

SoCalGas plans to provide information to customers and stakeholders regarding safety, information about the project, and how to contact SoCalGas, as indicated in Section OP 7h of Chapters 1 and 2 of the Joint Utilities' prepared testimony. Pursuant to D.22-12-

[5] UCI, Proposed Hydrogen Blending Demonstration Project, *available at*: https://uci.edu/hydrogen/.

057, Ordering Paragraph 7, because the projects are intended to, among other things, measure air emissions impacts (as outlined in Exhibit 1A of Chapter 1 testimony), SoCalGas does not intend to provide speculative materials concerning “pollution-related risks of hydrogen blending” claimed by Sierra Club.

Regarding continuous emissions monitoring, SoCalGas intends to align emissions testing with the associated Air Quality Management District protocol where the project is located and with input from an independent third-party on a monthly basis for the Closed System Project and on a basis determined through customer input for the Open System Project. Regarding the Closed System Project, end-use equipment being evaluated is generally commercial heating equipment, with some foodservice equipment. This level of equipment is generally evaluated at manufacturer certification or through yearly permit compliance with SCAQMD. SoCalGas is proposing to measure emissions on a monthly basis, which is more frequent than what is required by SCAQMD. Regarding the Open System Project, SoCalGas would like to be sensitive to the customers and residents in the community, and their level of comfortability with performing emissions testing. Therefore, SoCalGas will be performing emission testing based on the feedback received in customer surveys, as outlined in Chapter 2, Table 3, of the Joint Utilities’ prepared testimony. For both of SoCalGas’s proposed projects, SoCalGas is open to evaluating if continuous emissions monitoring is feasible in alignment with an independent third-party.

<u>Leakage</u>

The Sierra Club Letter recommended employing “…continuous leakage monitoring systems whose reliability has been established and whose results can be tracked and reported.” As outlined in the Amended Application, p. 20, SoCalGas has clarified that continuous monitoring for hydrogen leakage on the production, storage, and blending area and automatic shutdown should a leak be detected will be incorporated.

QUESTION 17

Please produce all written comments, questions, or other communications that SoCalGas received from workshop participants following the June 13, 2023 and November 6, 2023 stakeholder workshops.

RESPONSE 17

SoCalGas objects to this request to the extent that it seeks documents that contain confidential information, including proprietary, market sensitive information disclosed during contractual negotiations, employee's names and contact information, and customer information. Subject to and without waiving these objections, SoCalGas responds as follows:

SoCalGas did not receive any written comments, questions, or other communications following the June 13, 2023, stakeholder workshop. In addition to the Sierra Club Letter dated November 15, 2023, SoCalGas received one other written communication following the November 6, 2023, stakeholder workshop. That communication is provided as Attachment 17 produced subject to SoCalGas's Non-Disclosure Agreement with Sierra Club.

DATE REQUESTED: MARCH 29, 2024
DATE SUBMITTED: APRIL 16, 2024

QUESTION 18

Please produce all written communications that SoCalGas provided in response to submitted questions or feedback following the June 13, 2023 and November 6, 2023 stakeholder workshops.

RESPONSE 18

SoCalGas objects to this request to the extent that it seeks documents that contain confidential information, including proprietary, market sensitive information disclosed during contractual negotiations, employee's names and contact information, and customer information. Subject to and without waiving these objections, SoCalGas responds as follows:

Following the June 13, 2023, stakeholder workshop, SoCalGas provided written responses to questions it did not have time to respond to during the workshop. The responses are provided in Attachment 18. Please refer to Attachment 17 regarding SoCalGas's written communications following the November 6, 2023, workshop produced subject to SoCalGas's Non-Disclosure Agreement with Sierra Club.

QUESTION 19

Please provide all emails between SoCalGas and University of California Irvine employees and representatives, including student and/or staff organizations, related to the Closed System Project.

RESPONSE 19

SoCalGas objects to this request because it is unduly burdensome, overly broad, and seeks documents that are irrelevant and/or not reasonably calculated to lead to the discovery of admissible evidence. SoCalGas further objects to this request to the extent that it seeks documents that contain confidential information, including proprietary, market sensitive information disclosed during contractual negotiations, employee's names and contact information, and customer information. Subject to and without waiving these objections, SoCalGas responds as follows:

Subject to SoCalGas's Non-Disclosure Agreement with Sierra Club, SoCalGas will produce, on a rolling basis, documents that are reasonably responsive to the (1) planning, design, construction, and commissioning, (2) testing and demonstration, and (3) decommissioning, equipment removal, and system restoration of the Closed System Project, as defined in the Amended Application. The production will be limited to documents dated on or before March 1, 2024, the date the Amended Application was filed. SoCalGas also notes that, in responding to this question, it provided this question to the current business unit personnel most likely to have information relevant to this response. SoCalGas's response relies on the memories of individuals and therefore may not capture the emails referred to in this question. SoCalGas further interprets the term "emails" to not include electronic meeting invitations (i.e., Outlook Calendar invites).

QUESTION 20

Please list all sites that SoCalGas considered for the Open System Project.

RESPONSE 20

SoCalGas objects to this request on the grounds that it is vague, ambiguous, and unintelligible, and on that basis, SoCalGas is unable to respond. SoCalGas further objects to this request pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure on the grounds that it seeks the production of information that is neither relevant to the subject matter involved in the pending proceeding nor is likely reasonably calculated to lead to the discovery of admissible evidence.

QUESTION 21

Page 7 of Chapter 2 of the Joint Utilities' prepared testimony, lines 7-8, state that "The Commission's Energy Division later clarified that the lower-level blends should be performed in an open portion of the distribution system," and footnote 11 states that this clarification occurred "in a virtual meeting held in January 2023."

a. Please provide all notes, minutes, agendas, or other written or recorded audio or visual documentation from the January 2023 meeting referenced in Mr. Waymire's testimony, as well as a list of meeting attendees.

b. Please provide a list of all meetings between SoCalGas and the Commission's Energy Division regarding the Hydrogen Blending Demonstration Projects, including all written notes, minutes, agendas, or other documentation of the meetings and identifying all meeting attendees.

c. Please provide all emails between SoCalGas and the Commission's Energy Division regarding the Open System Project.

RESPONSE 21

a. SoCalGas objects to this request pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure on the grounds that it seeks the production of information that is neither relevant to the subject matter involved in the pending proceeding nor is likely reasonably calculated to lead to the discovery of admissible evidence. SoCalGas further objects to this request to the extent that it seeks documents protected by the attorney-client privilege and/or attorney work product doctrine. Subject to and without waiving the foregoing objections, SoCalGas responds as follows:

   The following is a summary of the January 2023 meeting with the Commission's Energy Division:

   SoCalGas, San Diego Gas & Electric Company (SDG&E), and Southwest Gas Corporation (Southwest Gas) had a 30-minute meeting with Energy Division Staff to seek clarification on a few provisions within D.22-12-057 of the Biomethane OIR, which directed the utilities to file an application proposing hydrogen blending projects. SoCalGas inquired about the status of the pending Administrative Law Judge (ALJ) ruling that would direct the utilities to amend Application (A.) 22-09-006, but Energy Division could not provide any insight on timing or the ALJ's thoughts on final direction.

   A key issue the utilities were seeking clarification on was regarding the percent blend the pilots should include in their program design. The Commission's expectation is that the utilities would develop a pilot in an open system to determine system impacts at 0.10% to 5% hydrogen blends and study higher blends in a closed system. Since Pacific Gas and Electric Company (PG&E) was not part of A.22-09-006, Energy Division suggested that the utilities collaborate with PG&E so that the pilots proposed are complementary.

The utilities also shared with Energy Division that they were planning to put together a public workshop and possibly a Technical Advisory Committee (TAC) to seek input/guidance to fulfill the requirement to incorporate stakeholder input/feedback in final project design. Energy Division Staff seemed amenable to this approach and wanted the utilities to meaningfully engage with proposed TAC members and incorporate their feedback.

Finally, since D.22-12-057 adopted a definition of clean renewable hydrogen, Energy Division recognized that the type of hydrogen to be used in the proposed projects may not meet the definition. Energy Division acknowledged that the use of clean renewable hydrogen is not required by D.22-12-057 but encouraged the utilities to address this in the amended application/new application.

b. SoCalGas objects to this request pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure on the grounds that it seeks the production of information that is neither relevant to the subject matter involved in the pending proceeding nor is likely reasonably calculated to lead to the discovery of admissible evidence, in particular with respect to meetings not identified in the testimony. SoCalGas further objects to this request to the extent that it seeks documents protected by the attorney-client privilege and/or attorney work product doctrine.

c. SoCalGas objects to this request because it is unduly burdensome, overly broad, and seeks documents that are irrelevant and/or not reasonably calculated to lead to the discovery of admissible evidence. SoCalGas further objects to this request to the extent that it seeks documents that contain confidential information, including proprietary, market sensitive information disclosed during contractual negotiations, employee's names and contact information, and customer information. Subject to and without waiving these objections, SoCalGas responds as follows:

After conducting a diligent search and reasonable inquiry, SoCalGas did not find any emails between SoCalGas and Energy Division regarding the Open System Project.

QUESTION 22

Chapter 2 of the Joint Utilities' prepared testimony, page 18, lines 4-5 state that "SoCalGas has worked closely with the City of Orange Cove" as part of its stakeholder engagement. Page 18, lines 22-23 also reference "project briefings with elected officials" and a presentation to the Orange Cove City Council. With regard to the Open System Project, please provide the following:

a. A list of all meetings (virtual, in person, telephonic, or otherwise) between SoCalGas staff and City of Orange Cove representatives at which the Open System Blending Project was discussed. Please include the location of each meeting and a list of attendees;

b. All presentation materials that SoCalGas has presented to Orange Cove elected officials, City Council, or the general public;

c. All emails between SoCalGas and City of Orange Cove representatives regarding the Open System Project.

RESPONSE 22

a. SoCalGas objects to this request pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure on the grounds that it seeks the production of information that is neither relevant to the subject matter involved in the pending proceeding nor is likely reasonably calculated to lead to the discovery of admissible evidence, including but not limited to a list of attendees. SoCalGas further objects to this request to the extent that it seeks documents that contain confidential information, including proprietary, market sensitive information disclosed during contractual negotiations, employee's names and contact information, and customer information. Without waiving and subject to these objections, SoCalGas responds as follows:

   A list of meetings between SoCalGas staff and the City of Orange Cove representatives at which the Open System Project was discussed is provided below. Please note that SoCalGas interprets telephonic meetings as formal, scheduled discussions.

   - **August 4, 2023** – City of Orange Cove invited SoCalGas to present hydrogen 101 and tour the city.
   - **October 12-13, 2023** – SoCalGas hosted elected officials from the City of Orange Cove, City Manager Daniel Parra, Councilmembers Josie Cervantes and Esperanza Rodriguez, Tulare County EDC president/CEO

Airica de Oliveira, and Fresno County EDC CS Manager Julian Ramos learn about the H2 Innovation Experience in the city of Downey, CA.

- **October 17-18, 2023** – SoCalGas hosted elected officials from City of Orange Cove, Councilmember Gilbert Garcia, Councilmember Diana Guerra Silva, Fire Chief Tom Greenwood and Public Works Director Dario Dominquez to learn about the H2 Innovation Experience in the city of Downey, CA.
- **November 8, 2023** – SoCalGas presented at the Orange Cove City Council regarding the proposed hydrogen blending demonstration project and invited residents to attend the community engagement meeting/townhall.
- **November 9, 2023** – SoCalGas in collaboration with the City of Orange Cove hosted a community engagement meeting/townhall to share plans about the proposed hydrogen blending demonstration project to the community.
- **February 28, 2024** – SoCalGas announced during the City of Orange Cove City Council meeting that the city was selected as the hydrogen blending demonstration project site.

b. A copy of the presentation materials as well as a fact sheet provided to the community are included as Attachment 22.b.

c. SoCalGas objects to this request because it seeks documents that are irrelevant and/or not reasonably calculated to lead to the discovery of admissible evidence. SoCalGas further objects to this request to the extent that it seeks documents that contain confidential information, including proprietary, market sensitive information disclosed during contractual negotiations, employee's names and contact information, and customer information. Subject to and without waiving these objections, SoCalGas responds as follows:

   Subject to SoCalGas's Non-Disclosure Agreement with Sierra Club, SoCalGas will produce as Attachment 22.c documents that are reasonably responsive to the (1) planning, design, construction, and commissioning, (2) testing and demonstration, and (3) decommissioning, equipment removal, and system restoration of the Open System Project, as defined in the Amended Application. The production will be limited to documents dated on or before March 1, 2024, the date the Amended Application was filed. SoCalGas also notes that, in responding to this question, it provided this question to the current business unit personnel most likely to have information relevant to this response. SoCalGas's response relies on the memories of individuals and therefore may not capture the emails referred to in this question. SoCalGas further interprets the term "emails" to not include electronic meeting invitations (i.e., Outlook Calendar invites).

QUESTION 23

Page 2 of Chapter 2 of the Joint Utilities' prepared testimony states that "the City of Orange Cove hosts various mixed material gas pipeline and vintages with steel, polyethylene (PE) and Aldyl-A pipeline materials."

a. Please identify all types of steel alloys and plastic materials in the portion of the distribution system SoCalGas intends to use for this pilot project.

b. Please provide a list of all types of steel alloys and plastic materials used throughout SoCalGas' low-pressure distribution system.

c. Is it SoCalGas' position that the pipeline materials in Orange Cove are representative of the materials and vintages used throughout SoCalGas' low-pressure distribution system? If yes, please provide the basis of that position.

RESPONSE 23

a. The plastic material identified in the portion of the distribution SoCalGas intends to use for the hydrogen blending demonstration is MDPE. The steel material identified in the portion of the distribution SoCalGas intends to use for the hydrogen blending demonstration is Carbon Steel.

b. SoCalGas does not have pipelines categorized as "low-pressure" as part of its distribution system.

c. SoCalGas does not have pipelines categorized as "low-pressure" as part of its distribution system.

QUESTION 24

Page 9 of Chapter 2 of the Joint Utilities' prepared testimony describes a solar array that will be installed "to produce the electricity required for operation of the electrolyzer and associated equipment needed for hydrogen production." Will the new solar array provide 100% of the electricity for the electrolyzer and associated hydrogen production equipment? If not, please identify the portion of the electricity that will come from the new solar array and the source of the remainder of the electricity.

RESPONSE 24

Yes, preliminary calculations show that the amount of solar proposed for the project along with battery and hydrogen storage will be sufficient to power the electrolyzer and associated hydrogen production equipment for the entirety of the Closed System Project. There are plans for a power interconnection to the electric grid as stated in Chapter 2 testimony. The solar array is also intended to feed excess renewable energy into the electric grid, should there be overproduction. Unforeseen circumstances may result in the project relying on the electric grid more than calculated to support auxiliary equipment.

QUESTION 25

Page 13 of Chapter 2 of the Joint Utilities' prepared testimony states customer equipment checks for emissions will be performed on a frequency "to be determined based on comprehensive customer survey." Please provide the most recent draft of the customer survey and identify what frequencies are under consideration.

RESPONSE 25

The comprehensive customer survey has not been developed. It will be developed upon approval of the Amended Application and the frequency of the survey will depend upon response rates of the initial survey distributed to customers.

<u>QUESTION 26</u>

Page 18 of Chapter 2 of the Joint Utilities' prepared testimony states that SoCalGas "facilitated tours with community leaders, including city officials, first responders and business organizations of SoCalGas's H2 Innovation Experience."

a. Please explain what SoCalGas's H2 Innovation Experience is (i.e., facilities, location, equipment, and procedures and components of the tour).

b. Please provide a list of all tours of the H2 Innovation Experience attended by Orange Cove city officials, first responders, and/or business organizations. For each tour, please provide a list of attendees.

c. Please provide any written communications from Orange Cove tour attendees regarding the H2 Innovation Experience and any responses from SoCalGas.

<u>RESPONSE 26</u>

a. The H2 Innovation Experience is a hydrogen powered microgrid and home located in Downey, California, at SoCalGas's Energy Resource Center (ERC). This project demonstrates how carbon-free hydrogen gas made from renewable electricity can be used in pure form or as a blend to fuel energy systems and communities of the future.

   The facility is comprised of solar panels, a power storage battery system, an electrolyzer to produce hydrogen, a fuel cell that uses excess hydrogen to generate electricity, and a blending skid that allows for the blend of 20% by volume hydrogen to feed the appliances within the home.

   The tours provide an overview of the microgrid as well as an inside look of the hydrogen home, including a demonstration of various common appliances running on blended natural gas and hydrogen along with a visual showcase of a blended flame.

b. SoCalGas objects to this request pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure on the grounds that it seeks the production of information that is neither relevant to the subject matter involved in the pending proceeding nor is likely reasonably calculated to lead to the discovery of admissible evidence, including the request to provide a list of attendees. Subject to and without waiver of the foregoing objection SoCalGas responds as follows:

   The tours were provided to the City of Orange Cove, Fresno County Economic Development Corporation, and Tulare County Economic Development Corporation.

c. There are no written communications from the City of Orange Cove attendees regarding the H2 Innovation Experience or responses from SoCalGas.

QUESTION 27

Page 19 of Chapter 2 of the Joint Utilities' prepared testimony states that "SoCalGas will work with the local community to identify relevant community-based organizations (CBO) for project engagement." Please list all CBOs that SoCalGas is considering for collaboration on the Open System Project.

RESPONSE 27

SoCalGas has not yet identified specific CBOs to engage on this project. However, SoCalGas will collaborate with the City of Orange Cove to identify the most appropriate CBOs or community outreach groups for project engagement.

QUESTION 28

Page 4 of Chapter 2 of the Joint Utilities' prepared testimony lists examples of equipment that will receive the hydrogen blend in the Open System Project, including "water heaters, furnaces, common cooking appliances, and commercial space and water heating."

a. Has SoCalGas compiled an inventory of all gas end use equipment that will receive the blend? If so, please provide that inventory.

b. Please identify all equipment types that will use a hydrogen blend in this pilot that are difficult-to-decarbonize.

RESPONSE 28

a. SoCalGas has not compiled a comprehensive inventory of all gas equipment in the community that will receive the blend. However, SoCalGas has confirmed via internal service technicians that common appliances including water heaters, furnaces, common cooking appliances, and commercial space and water heating are present in the community. SoCalGas will continue to work with the city, residents, and the city's businesses to best identify end-use equipment in the community.

b. SoCalGas objects to this request pursuant to Rule 10.1 of the Commission's Rules of Practice and Procedure on the grounds that it seeks the production of information that is neither relevant to the subject matter involved in the pending proceeding nor is likely reasonably calculated to lead to the discovery of admissible evidence. SoCalGas further objects to this request on the grounds that it is vague and ambiguous, particularly with respect to the phrase "difficult-to-decarbonize," which SoCalGas did not use in the Amended Application. SoCalGas also objects to this request because it misconstrues SoCalGas's testimony.

QUESTION 29

Page 10 of Chapter 2 of the Joint Utilities' prepared testimony states that "water will be sourced from sustainable sources whenever possible."

a. Please clarify with more specificity what "sustainable sources" means in this sentence.

b. Please list all sources of water SoCalGas is considering for the Open System Project. For each source, please indicate whether SoCalGas considers the source sustainable or not.

c. What are the water requirements of SoCalGas' proposed Open System Project (in gallons, liters, or acre-feet, etc., of water)?

RESPONSE 29

a. SoCalGas intended the term "sustainable sources of water" to reference sources that can be readily maintained without significantly impacting existing beneficial uses of water.

b. At this stage of the planning, specific water sources for the Open System Project have not yet been identified. SoCalGas will work with the City of Orange Cove to identify suitable water sources consistent with the City of Orange Cove's water conservation and management goals. Additional analysis may be completed concerning competing water demands and potential supply constraints when specific water sources are identified.

c. Preliminary water requirements are estimated as 2.3-2.97 gallons of demineralized water per 1 kg of Hydrogen produced.

QUESTION 30

Page 11 of Chapter 2 of the Joint Utilities' prepared testimony states that "prior to the introduction of hydrogen, SoCalGas will conduct an asset review and inspection, and will baseline the demonstration area with regular natural gas. All customer appliances involved in the demonstration in the City of Orange Cove will be offered courtesy inspections to confirm the appliances are in safe working order."

a. Please explain the process of an "asset review and inspection" and identify all facilities, equipment, or other assets that are included in the process.

b. Will SoCalGas require passing inspections of all end use customer equipment that will receive the hydrogen blend prior to commencement of blending?

c. What procedure will SoCalGas follow if a building occupant either refuses a courtesy inspection or does not respond to the offer?

d. Does SoCalGas plan to track and/or report modifications or repairs made to end use equipment pursuant to these inspections?

RESPONSE 30

a. For the Open System Project, an asset review and inspection will consist of a visual review of all components leading from the hydrogen production, storage, and blending areas, up to the meters serving customers. This way, SoCalGas can take into account the various meter types in the area. In some cases, if a customer wishes for an in-home inspection to be performed, this will also take into account inventory of end-use appliances. The inspection will also involve a baseline leak detection survey of the pipeline system and meters, prior to the introduction of hydrogen. The asset review and inspection process intends to document data on materials, pipelines, meters, and end-use equipment that is available prior to the start of the demonstration. The asset review and inspection process will also take a full inventory of hydrogen production, blending, and storage equipment and verify that it is in working order.

b. SoCalGas objects to this request on the grounds that it is vague and ambiguous, particularly with respect to the phrase "require passing inspections." Subject to and without waiving the foregoing objection, SoCalGas responds as follows:

   As indicated in Chapter 2, Table 3, SoCalGas will offer end-use equipment evaluations to confirm the equipment is working properly, prior to the commencement of hydrogen blending.

c. SoCalGas will offer courtesy inspections to confirm the appliances are in safe working order. A SoCalGas customer has the right to refuse or not respond to a courtesy inspection, and therefore, SoCalGas would allow the customer to exercise the right to not accept a courtesy inspection.

d. SoCalGas objects to this request on the grounds that it is vague and ambiguous, particularly with respect to the phrase "modifications or repairs made to end use equipment." Subject to and without waiving the foregoing objection, SoCalGas responds as follows:

   SoCalGas intends to track equipment modifications and repairs, although they are not anticipated.

QUESTION 31

Page 16 of Chapter 2 of the Joint Utilities' prepared testimony identifies "hydrogen safety education for personnel" as a safety effort SoCalGas plans to take as part of the Open System Project.

a. Please clarify who "personnel" refers to in this statement.

b. Does SoCalGas intend to provide hydrogen safety education to all project participants (i.e., all occupants of buildings that will receive the hydrogen blend)?

c. Please provide all written or otherwise recorded (e.g., audio or video) hydrogen safety education materials that SoCalGas plans to provide as part of this safety effort.

RESPONSE 31

a. "Personnel" refers to SoCalGas operators and contractors that are responsible for operating and maintaining the facility along with first responders that are responsible for responding to the City of Orange Cove.

b. SoCalGas will provide public safety information to all project participants, including hydrogen safety response instructions and a dedicated means of communication with SoCalGas. However, operator specific education would be intended for those personnel identified in Response 31.a.

c. Hydrogen safety education material is in development and will use resources and training from reputable organizations and entities such as the *Introduction to Hydrogen Safety for First Responders* training from the American Institute of Chemical Engineers (AIChE).[6]

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[6] See: https://www.aiche.org/ili/academy/courses/ela253/introduction-hydrogen-safety-first-responders?gad_source=1&gclid=Cj0KCQjwztOwBhD7ARIsAPDKnkAUW7AQyzdcRSC-t3Li73q6xurlfXAcni3386Xu-KSxCiwpAkRvF1kaAi5UEALw_wcB.

QUESTION 32

For both the Open System Project and the Closed System Project, has SoCalGas quantified the greenhouse gas emissions impacts it projects to result from each hydrogen blending project? If so, please provide all documents analyzing or projecting greenhouse gas emissions impacts (reductions or additions) related to each project.

RESPONSE 32

SoCalGas objects to this request on the grounds that it calls for speculation and the request seeks irrelevant information not reasonably calculated to lead to the discovery of admissible evidence. Subject to and without waiving the foregoing objections, SoCalGas responds as follows:

SoCalGas has not quantified any potential greenhouse gas emissions impacts, whether positive or negative, it projects to result from either the Open System Project or the Closed System Project. However, SoCalGas does plan to perform emissions testing for various end use equipment, including CO2 emissions. Please see Exhibit 1A, SoCalGas's Preliminary Data Collection Plan, of Chapter 1 of the Joint Utilities' prepared testimony.

QUESTION 33

Please provide all emails between SoCalGas and California Energy Commission staff regarding the development of both the Open and Closed System projects.

RESPONSE 33

SoCalGas objects to this request because it is unduly burdensome, overly broad, and seeks documents that are irrelevant and/or not reasonably calculated to lead to the discovery of admissible evidence. SoCalGas further objects to this request to the extent that it seeks documents that contain confidential information, including proprietary, market sensitive information disclosed during contractual negotiations, employee’s names and contact information, and customer information. Subject to and without waiving these objections, SoCalGas responds as follows:

No emails exist between SoCalGas and CEC staff regarding the development of the hydrogen blending demonstration projects.

Amended Hydrogen Blending Demonstration Application (A.22-09-006)
Sierra Club DR-04

Attachment 4.a

Final Report - Draft

Power-to-Gas Demonstration: Dynamic Operation and Hydrogen Injection Impacts

To:

Southern California Gas Company
c/o: [redacted] Advanced Technologies, Strategy & Development
Southern California Gas Company, a Sempra Energy Utility
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From:

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January 30, 2019

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1 Executive Summary

Power-to-gas (P2G) is an emerging technology concept in which electrical energy storage is provided in the form of compressed gaseous fuel. In P2G, otherwise curtailed electricity from the increasing amount of variable renewable energy resources (VRES) on the grid can be utilized to produce sustainable gaseous fuel which can potentially be stored in the existing gas grid. The Southern California Gas Company in collaboration with The National Fuel Cell Research Center (NFCRC) at the University of California Irvine (UCI) has carried out the United States first demonstration of P2G utilizing the hydrogen in gas grid (HIGG) pathway.

In this study, a PEM electrolyzer was modified to have dynamic dispatch capabilities, then subsequently operated and studied in detail as a part of the UC Irvine P2G demonstration. The system operated at sustained part load conditions and load followed variable renewable energy resources. Furthermore, the impact on emissions due to the addition of hydrogen to the high pressure natural gas fuel feed to the University of California Irvine (UCI) Central Plant's combustion turbine is analyzed.

The major accomplishments and findings of our research are:

- Load following capabilities of the 60kW PEM electrolyzer system was assessed using campus solar PV resources and California-based aggregated wind assets.

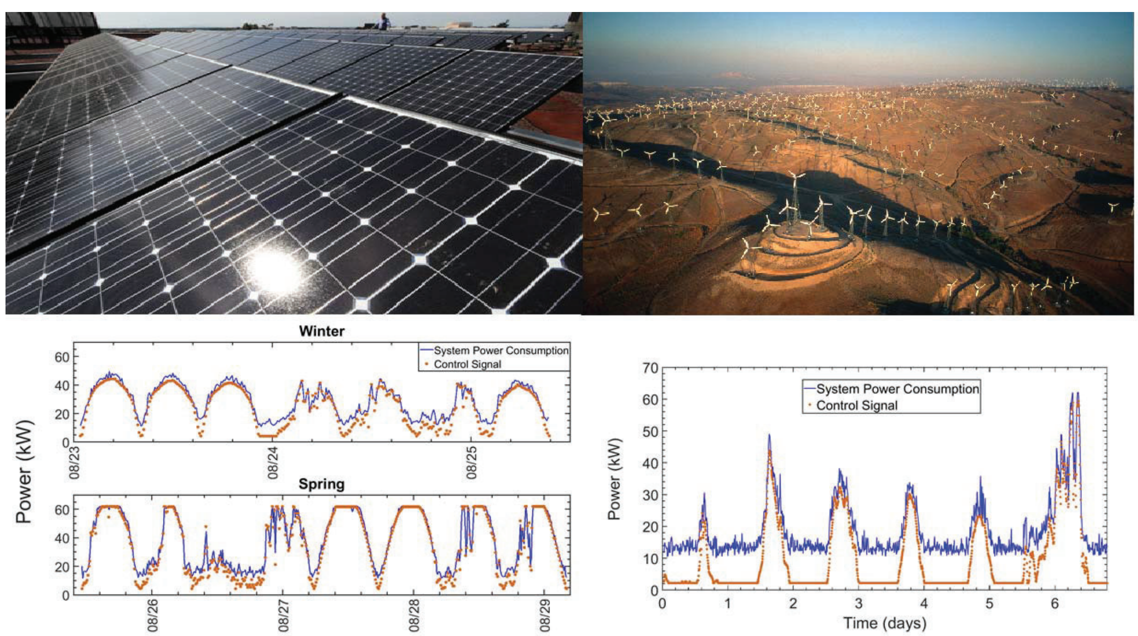


Figure 1. (Top left) Rooftop solar PV resources at UC Irvine's MSTB building used for the solar PV load following tests (bottom left). (Top right) Tehachapi wind turbine array, data from which was employed for the wind asset load following tests (bottom right).

Major Findings: 1)Through employment of a novel control scheme not involving any modification of the commercial PEM electrolyzer platform, load following of the most extreme transients introduced by both campus solar PV resources (left) and aggregated California wind assets out of T'hachapi (right) was accomplished. 2) Minimum cold start-up time of just under five minutes. From a 'warm' or energized state, system is able to ramp from minimum to full load in under a second. 3) A control strategy involving de-energizing the system at load conditions of 14 kW (~22.5% of rated power) dramatically improves overall system efficiency in highly transient load following scenarios.

- The impacts of operational parameters (load condition, operating temperature, hydrogen pressure, and more) on 60 kW PEM electrolyzer system components and stack performance were investigated.

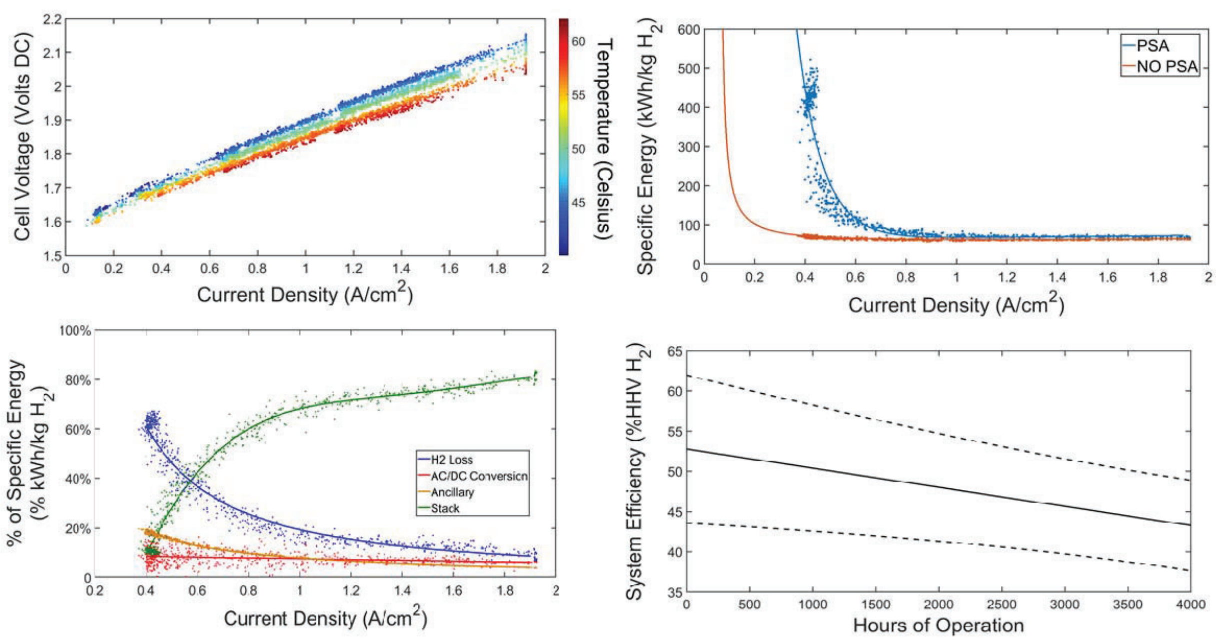


Figure 2. (Top Left) Stack temperature influence on j-V curve (Top right) System performance at part load with and without PSA dryer. (Bottom Left) Percentage of measured energy consumption by major system components. (Bottom Right) System efficiency over total hours of operation with 95% confidence intervals.

Major Findings: 1) While operating temperature is a major influence on stack performance, from a system efficiency perspective the operating pressures are more significant due to system level losses that depend on pressure as well as gas cross-over in the stack. 2) Operation of PEM electrolyzers at low load conditions leads to severe performance drop-offs. Modification of the hydrogen purification processes can extend the effective range of load condition for applications not requiring high purity hydrogen gas such as pipeline injection. 3) No appreciable degradation observed for the 4000 hours of operation.

- Energy demands associated with the electrochemical compression of hydrogen in-situ with electrolysis were characterized. Loss of hydrogen due to cross-over of gases in the stack at elevated pressures was estimated and included in this characterization.

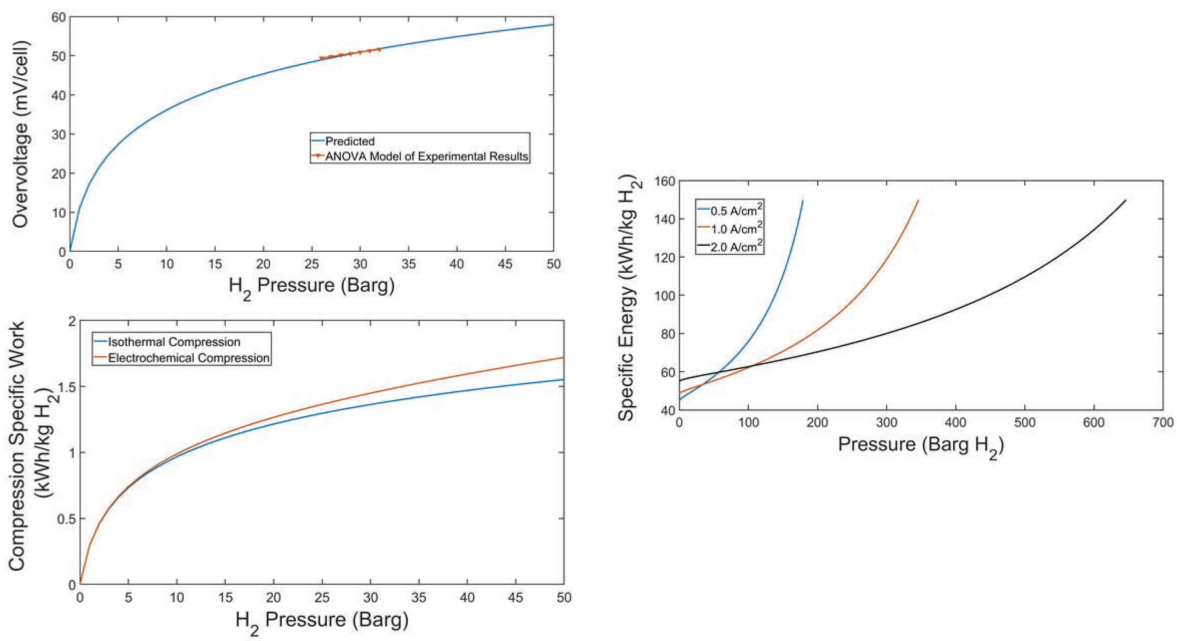


Figure 3. (Top Left) Overvoltage per cell measured versus prediction by Nernst Equation. (Bottom Left) Actual performance of electrochemical compression via electrolysis versus ideal isothermal compression. (Right) Specific energy requirements of pressurized electrolysis at different current densities with increasing pressure.

Major Findings: 1) Overvoltage due to pressurization of hydrogen matches closely with Nernst prediction. 2) Hydrogen loss due to cross-over of pressurized gas in the stack is significant and needs to be taken into account when pressurizing hydrogen via electrolysis. 3) At pressures below 100 barg, electrochemical compression via electrolysis is an effective method for compression of hydrogen gas. At higher pressures, higher minimum load conditions are needed to ensure safe mixtures of H_2 in O_2 and realize practical efficiencies.

- Modern electrolyzer system controls make it possible to effectively predict system power consumption and species transport with a simple isobaric and isothermal analytical model.

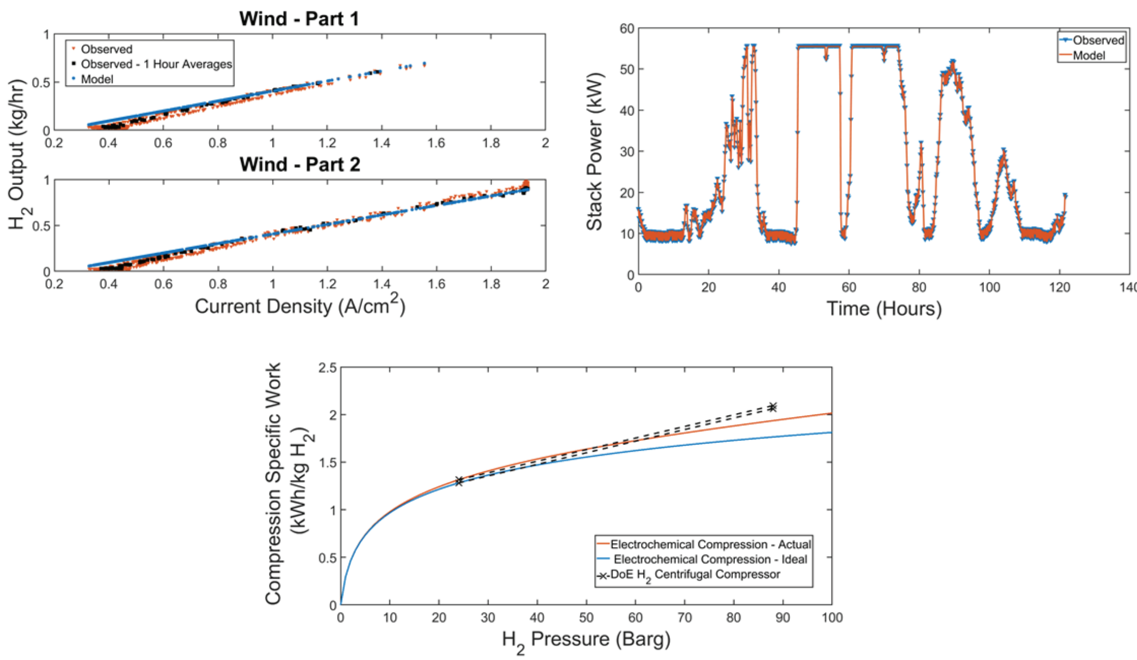


Figure 4. (Top Left) Predicted hydrogen output model versus measurements for wind load following. (Top Right) Predicted stack power consumption for wind load following. (Bottom) Predicted compression work of electrochemical compression via electrolysis versus DoE state of the art H_2 centrifugal compressor design.

Major Findings: 1) A simplified isobaric, isothermal, 0-D stack model with simplified assumed losses for system components can accurately predict system consumption and species output/consumption for PEM electrolyzer system. 2) This model was applied to compare the suitability of PEM electrolysis based electrochemical compression for pipeline injection scenarios and hydrogen fueling station, the former of which is a well suited application whereas for the latter external compression methods would be recommended.

- The addition of hydrogen to a natural gas fired gas turbine was accomplished; with up to

0.5% by volume H_2 for over 3000 hours of electrolyzer based injection and a total of 2400 kg of H_2 injected in long term testing, and up to 3.4% by volume H_2 in the short term high throughput injection.

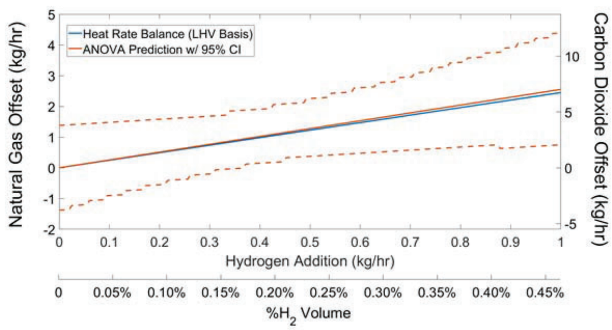


Figure 5. (Left) Observed offset of natural gas with addition of hydrogen with 95% confidence intervals. (Right) Siting of 60 H_2 cylinders for large-scale hydrogen injection.

Major Findings: 1) Analysis of long-term low throughput hydrogen injection showed an average offset of 2.5 ± 1.75 kg natural gas per kg of H_2. Analysis of the results for the one-time high throughput hydrogen testing showed average offsets of 1.9 ± 1.85 kg natural gas per kg of H_2. 2) No notable impacts on emissions of CO or NO_x was observed at any level of hydrogen injection.

2 Introduction and Background

The push for sustainable energy systems has picked up considerable momentum, introducing increasingly rapid implementation of renewable generation resources that are largely intermittent in output. These variable renewable energy resources (VRES) introduce balancing challenges to the electrical power system that will require an overall more flexible energy system involving energy storage, management on the demand side, decentralization of energy and heating systems in some locales, and the interconnection of energy markets [1]. Electrical power systems looking to meet 80% or more of electrical power demand from VRES will require energy storage systems capable of shifting massive amounts of energy due to diurnal and even seasonal imbalances in VRES output [2]. Only pumped hydropower and fuel gas energy storage can meet the magnitude of energy and power capacity required for such scenarios [3]. Hydrogen energy storage is one such fuel gas approach that also provides the opportunity for interconnection of energy markets in the form of power-to-gas (P2G) [4]. Heide et al. demonstrated the need for hydrogen energy storage in a fully renewable European power system in regions of Europe that do not have sufficient pumped hydropower resources, such as Germany and the Netherlands [5]. It is no surprise then that the vast majority of power-to-gas projects are found in these regions. In the power-to-gas energy storage concept, hydrogen is produced directly from electricity via electrolysis, typically utilizing overgeneration from VRES resources. Hydrogen gas is a highly flexible energy vector, allowing arbitrage of excess electricity generation to a variety of sectors [6]. In industrial applications, hydrogen is key in the synthesis of ammonia, as well as the production of nickel, iron, glass and fibers [7]. H_2 can be sent to the transportation sector to provide fueling for fuel cell electric vehicles (FCEV). Hydrogen gas can also be dispatched back to the electrical grid in a power-to-gas-to-power (P2G2P) path, through either conventional combustion-based generation or potentially through near-zero emission fuel cells. Through power-to-gas, the carbon intensity of several end uses involving hydrogen could be directly reduced.

Hydrogen can be stored in dedicated hydrogen infrastructure, in the form of tanks and geological formations (such as salt caverns), or in existing natural gas infrastructure as either methane after being run through a methanation process or blended in with natural gas to create hydrogen enriched natural gas (HCNG). Salt caverns are already used today for storage of hydrogen [8], and their ability to hold quantities of hydrogen to provide load shifting on time scales from daily up to seasonal in a high wind power electrical system has been shown analytically [9].

The integration of hydrogen gas into pre-existing natural gas infrastructure is a promising pathway for adoption of P2G. Zeng et al. provided a thorough analysis on the increasing interdependence of electrical power and natural gas infrastructure, and illustrated the increase in renewable penetration and reduction in transmission losses achievable through power-to-gas [10]. There is already extensive natural gas infrastructure in many regions of the world that provides an immense magnitude of energy storage in the form of fuel. The introduction of renewably sourced hydrogen in increasing concentrations into existing natural gas infrastructure could provide for an increasingly carbon neutral gas-based energy system and contribute to the energy storage needs of a highly renewable electrical system without significant investment into entirely new energy transmission and storage infrastructure.

For these reasons, understanding the properties of hydrogen enriched natural gas and its effects on natural gas infrastructure and end uses is of critical importance for the successful implementation of power-to-gas. Currently, broad studies carried out in the European Union [11] and the United States [12] cite ranges of 5-15% by volume hydrogen in natural gas infrastructure as a reasonable target that involves minimal modification of end use appliances. Concentrations greater than 20-30% were found to be a definite safety risk without modification of end use appliances [11].

The current European Union (EU) energy roadmap, which aims for deep decarbonization of 80% carbon emission reduction and 75% renewable energy consumption by 2050, identifies the natural gas system as critical for meeting these goals due to the flexibility that gas-fired platforms provide [13]. There are several European power-to-gas projects demonstrating integration with natural gas infrastructure, with both methanation [14], and direct injection of hydrogen [15]. In the United States, the University of California Irvine P2G demonstration is the first P2G demonstration of direct hydrogen injection to natural gas infrastructure [16]. Table 1 outlines current P2G efforts involving hydrogen injection to existing natural gas infrastructure.

Table 1. Survey of several P2G projects involving hydrogen injection to natural gas grid.

Project & Location	Description	% H_2 in Natural Gas by Volume	
GRHYD Cappelle-la-Grande, France	Local gas grid – 100 households + Central Boiler	6% (Today) 20% (Projected)	[17]
HyDeploy Keele University, United Kingdom	Private gas grid – entire university campus	20% (Projected)	[18]
Jupiter 1000 Fos-sur-Mer, France	Transmission gas grid – both H_2 injection and methanation	Up to 5% (Projected)	[19]
Sustainable Ameland Ameland, Netherlands	Local gas grid – 14 homes	Up to 20% (Project Finished)	[20]
Strom-zu-gas Thüga Frankfurt, Germany	Local gas grid – distribution level	Below 2% (Today)	[21]
WindGas (2 Sites) Falkenhagen and Hamburg, Germany	Transmission gas grid	Below 2% (Project Finished)	[22]
WindGas Hassfurt, Germany	Distribution gas grid	5-10% (Today)	[23]
Wind2gas Brunsbüttel, Germany	Transmission gas grid	5% (Projected)	[24]
wind2hydrogen Auersthal, Austria	Transmission gas grid	1-10% (Today)	[25]
Regio Energie Solothurn, Switzerland	Transmission gas grid	Below 2% (Today)	[26]
Energiepark Mainz, Germany	Distribution gas grid	Up to 15% (Today)	[27]
P2G Demonstration University of California, Irvine, USA	Private gas grid – upstream of gas turbine	Up to 0.5% (Today) Up to 3.4% (Short Term)	

The myriad varieties of end-use equipment integrated with natural gas infrastructure, from cook-top burners in residential homes to massive natural gas combined cycle (NGCC) power plants, makes the transition to a hydrogen-enriched, and ultimately pure hydrogen fuel gas infrastructure a daunting task. While the substitution of natural gas with hydrogen gas directly takes a proportional amount of carbon out of the combustion reaction for traditionally natural gas fed end uses, the effects of hydrogen addition on emissions of criteria pollutants (Carbon monoxide and oxides of nitrogen primarily), flame stability, and natural gas infrastructure are also of concern.

The addition of hydrogen to natural gas has shown reductions in emissions of carbon monoxide (CO) and nitrogen oxides (NO_x) in some end uses [28] [29], but led to an increase in NO_x emissions in other cases [30] [31]. There is also indication that the addition of hydrogen reduces the emissions of particulate matter due to partial combustion of lubricating oil in natural gas fired engines [32]. Complex combustion systems such as gas turbines have been identified as being of particular concern with the addition of even small concentrations of hydrogen to natural gas, with as little as 1% by volume hydrogen being recommended by literature for unmodified engines, allowing upwards of 5-10% by volume hydrogen with tuning and/or modifications [33] [34].

3 Dynamic Operation of PEM Electrolyzer System

In this chapter, a 60kW PEM electrolyzer system is tested in P2G operation conditions, assessing baseline performance, part load operation capabilities, VRES load following (solar PV and aggregated wind assets), start-up capabilities, and the influence of changing operation conditions from both a stack (electrolysis) and system level perspective.

Proton exchange membrane (PEM) electrolyzers are a relatively young electrolyzer technology, having been in development for only the last 20 years [35]. The electrolyte membrane for which it is named consists of a solid polymer of the perfluorosulfonic acid family, with carbon-supported platinum electrocatalyst layers on each side, which allows for dissociation of cations when wet and the subsequent transport of hydrogen ions (H^+) across the membrane [36]. PEM electrolyzers are low temperature systems that are typically operated below 100ºC as the membrane must be hydrated to facilitate ion conduction. In lab environments, PEM stack efficiencies have been demonstrated as high as 85% higher heating value [37] [38]. State of the art commercial PEM electrolyzer system efficiencies at large scale are found typically between 67% and 75% of higher heating value [39].

Publications on PEM technology are more often concerned with Proton Exchange

Membrane fuel cell systems, but within the last decade an increase e in interest towards PEM electrolyzer can be observed in the greater proportion of publications concerning PEM electrolyzer systems [40]. A number of modeling approaches have been able to analytically characterize the theoretical effects of varying operating conditions and physical design characteristics on cell and stack performance and shown good agreement with experimental data [41] [42] [43] [44] [45] [46] [47] [48]. Other efforts have also successfully characterized system level performance, incorporating the balance-of-plant into their models and having similar success with matching experimental system data [49] [50]. Further analytical studies have demonstrated the suitability of PEM electrolyzer systems integrated with variable renewable energy for the production of renewable hydrogen [51] [52] [53] [54], and further applied to a self-sustaining renewable hydrogen fueling station [55], reversible or 'regenerative' PEM fuel cell systems [56] [57] [58], and large scale power-to-gas scenarios [59]. Experimental studies have demonstrated the application of these systems for integration with variable renewable energy resources [60], in providing ancillary grid services [61], and have investigated the ability to electrochemically compress hydrogen in the electrolyzer stack, reducing or negating the requirement of additional compression equipment [62].

Proton Exchange Membrane electrolyzers show promising qualities for implementation within the power-to-gas concept. These systems can operate at part load capacities as low as 5% up to 100% without interruption [63]. They have shown the capability to load follow highly dynamic power inputs, as would be necessary for integration with solar or wind energy sources [63]. These are important qualities for successful power-to-gas integration with solar due to the likely need for relatively low capacity factors of the electrolyzer systems when utilized for absorbing large amounts of solar over-generation [64]. There exists the capability for hybrid 'reversible' PEM systems. These are systems that can run in both a fuel cell mode, generating electricity with hydrogen fuel input, and an electrolysis mode, generating hydrogen fuel for storage with electrical input. Maclay et al. was able to demonstrate the technological feasibility of such a system at a residential scale integrated with dynamic PV solar inputs as well as residential loads [65].

3.1 Experimental

The C10 system is a differential pressure proton exchange membrane (PEM) electrolyzer system. The '10' in C10 comes from the rated hydrogen gas (H_2) output rate of 10 normal cubic meters per hour (Nm^3/hr) at 30 barg and a purity of > 99.9998% H_2. Proton Onsite reports that detectable impurities come in the form of water vapor (H_2O (g) < 2 ppm), nitrogen gas (N_2 < 2 ppm), and oxygen gas (O_2 < 1 ppm). The system is rated for a 480VAC 3-phase 100kVa breaker, with a power consumption of 60kW and a specific energy consumption rate of 68.9 kilowatt-hours of electricity (kWh_{el}) per kg of H_2, for a higher heating value (HHV) system efficiency of 58.1%.

The C10 system is comprised of two separate cabinets, a 'fluids cabinet' containing the electrolysis stack and mechanical systems while an electrical cabinet houses the power conditioning equipment. This is done to prevent the introduction of relatively volatile hydrogen gas, which has a lower explosive limit (LEL) of 4% in air, to electrical components which could produce a spark and cause ignition in the presence of relatively small concentrations of hydrogen. The cabinets are connected by a wire way track that runs the direct current (DC) cables to the electrolysis stack in the fluids cabinet from the AC/DC rectifying power supply in the electrical cabinet (see Figure 6). Both cabinets in the C10 system are oversized, as the system architecture is intended to be upgradeable, allowing the addition of up to two more C series PEM stacks, for a total of three stacks in the fluids cabinet. Each stack would require an additional AC/DC rectifying power supply in the electrical cabinet.

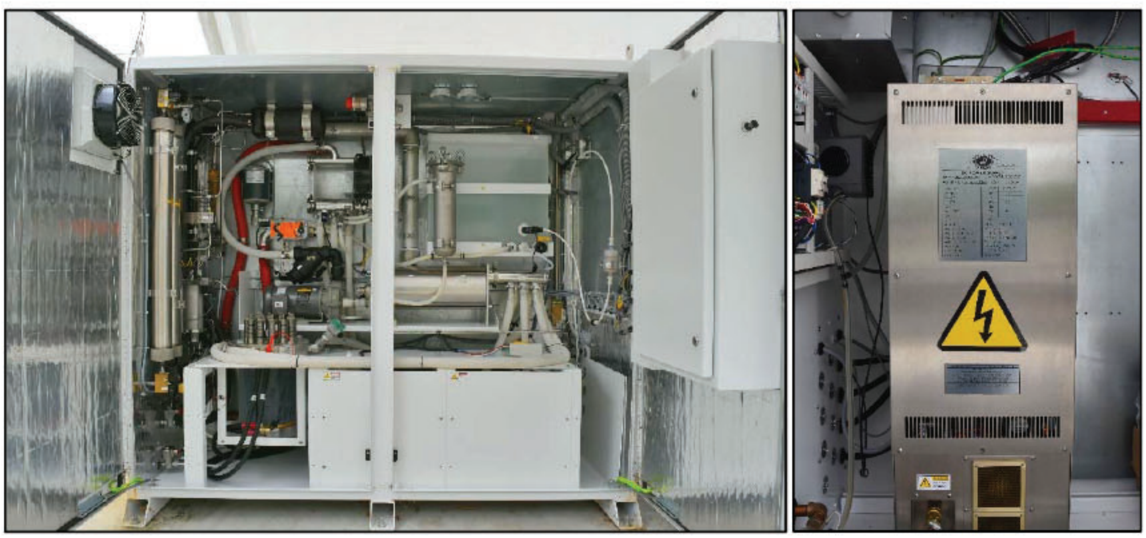


Figure 6. C10 electrolyzer system. Fluids cabinet containing mechanical systems and cell stack on the left, electrical cabinet containing the power electronics on the right.

3.1.1 Electrolysis Cell Stack

The C Series PEM electrolysis cell stack is built in-house by Proton Onsite for their C10/C20/C30 systems. The stack is rated at roughly 60 kW_{el} of electrical input, at a maximum current of 410 amps DC. Within typical operating parameters of the C10 system this power rating is not ever reached, though conditions resulting in higher cell potentials (lower temperature primarily) could result in power consumption on the order of $60kW_{el}$. The maximum pressure ratings are 34.5 barg H_2 gas on the hydrogen electrode and 2.76 barg O_2 gas on the wet electrode, and an operational temperature range of 5 to 65 C°.

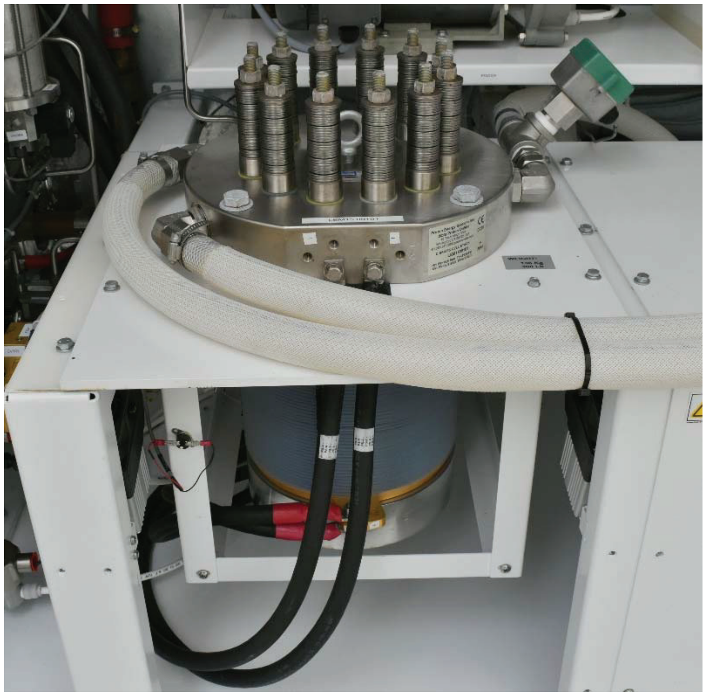


Figure 7. C10 Electrolyzer system proton exchange membrane cell stack.

The stack itself is comprised of 65 cells, with the negative potential endplate on the top, and the positive potential endplate on the bottom (Figure 7). There is one DI water inlet to the wet electrode, and a 'wye' configuration two hose outlet from the wet electrode to reduce the pressure drop coming out of the stack on the recirculating DI water feed. From the hydrogen electrode side, a 3/8" OD SS316 line carries wetted hydrogen out to the hydrogen management subsystem. Further information was provided for the purposes of this study by Proton Onsite concerning the cells structure and active cell area, which was given as 213.68 cm^2. Further details on the electrolysis cell known parameters and their values are given in Section 4.3, Table 11.

3.1.2 Hydrogen Management Subsystem

Generated hydrogen gas goes through a hydrogen management subsystem that maintains hydrogen pressure in the system up to the process connection, as well as removes to a high degree and recovers to some extent entrained water in the hydrogen gas stream. As hydrogen gas exits the cell stack, it enters a hydrogen water phase separator vessel where system-side hydrogen pressure is monitored and maintained. Water is dropped out by gravity in this vessel, and intermittently 'flushed' to send the water back into the DI water loop. From the hydrogen water phase separator, hydrogen gas passes through a heat exchanger before entering a secondary larger volume hydrogen water phase separator vessel, which prevents sudden buildup of hydrogen pressure on the system side.

After passing through the heat exchanger, hydrogen gas enters a pressure swing adsorption dryer system. The system is comprised of two dryer beds, each full of desiccant beads that selectively adsorb water at elevated pressure, drying the hydrogen gas to the high degree of purity the system is rated for, > 99.9998% H_2. One dryer bed flows hydrogen gas at a time, the 'dry bed', while the other bed depressurizes to allow adsorbed water to drop out, which is then purged out of the bed by a continuous slipstream of the dry hydrogen from the other bed. Upon this 'purge', the beds swap and the process repeats.

After the drying process a, a series of check valves, pressure transducers, and a back-pressure regulator control the output pressure of the hydrogen gas to the end process. This pressure feedback control loop is the primary control concerning the amount of electrical power delivered to the electrolysis process; balancing downstream tank/pipeline pressure with system hydrogen pressure.

3.1.3 Oxygen Management Subsystem

Generated oxygen gas is entrained in the water electrode and exits through the return DI water hose. This mixture goes to a water-oxygen phase separator, which separates the two through gravity. Oxygen gas exits to an exterior vent with a small amount of water. Sensors on this subsystem monitor the gas pressure and for the presence of hydrogen gas to prevent a flammable mixture. The pressure of the oxygen gas does not exceed 2.76 barg.

3.1.4 Deionized Water Management Subsystem

The electrolyzer consumes DI water at a rate of 9 L/hr and requires a delivery pressure of 1 to 4.1 barg. DI water quality must be at minimum ASTM Type II, resistivity > 1 MΩ-cm, but ASTM Type I, resistivity > 10 MΩ-cm is recommended to maximize the lifetime of the stack. Incoming water quality to the system is monitored at the system inlet, before a primary DI water tank that holds up to 56 L of DI water. Incoming water below 1 MΩ-cm for a sustained period (> 30 seconds) triggers a system failure even if recirculating water quality is maintained.
DI water from the main tank is introduced to the recirculating water loop through a secondary feed water pump (1.1 hp) to an internal DI water polishing bed, housing a mixed bead resin filter. A recirculating system water pump (3 hp) drives the DI water through a heat exchanger and then to the cell stack. When water is not being added from the main DI water tank, a portion of the recirculating water stream is diverted through the internal DI water polishing bed.

3.1.5 Data Acquisition Systems

An onsite Lenovo laptop serves as the data acquisition (DAQ) and control personal computer (PC) for the test bed. The C10 electrolyzer system has an internal data stream that provides high resolution, accurate data concerning the operation and control of the system through Modbus protocol. These metrics are collected in real time from the system by connection through an ethernet switch with proprietary software provided by Proton Onsite. Onboard metrics of interest to the study of the system include the system hydrogen pressure at the outlet of the hydrogen electrode (barg), oxygen pressure at the oxygen-water phase separator (barg), system water temperature at the outlet of the DI water subsystem heat exchanger (C°), hydrogen gas temperature at the hydrogen management subsystem heat exchanger (C°), the stack voltage (volts), and the stack current command signal (amps). The state of the system solenoid valves, water levels, coolant temperature at the heat exchangers, DI water quality at the inlet and in the recirculating water loop is also monitored and recorded.

To complement the on-board data acquisition and provide verification of some measurements, some external sensing was implemented. Power meters (Dent ElitePro®) at the electrolyzer system connection to the grid, on the electrolyzer system breaker to the ancillary power demands, and at the grid connection to the chiller system, recorded the net power consumption (kW), voltage across the 3-phases (volts AC), amperage across the 3-phases (amps AC), and the power factor. Having power monitoring on both the overall system consumption and on the ancillary systems circuit allowed for the characterization of the AC electricity consumption of the electrolysis process separate from the electrical power needed to run the pumps, blowers, valves, etc.; that make up the ancillary power demands.

An additional Dent ElitePro® system was connected to the cell stack to independently measure the stack voltage at a higher resolution than the internal data stream and also served to verify the on-board system measurements.

The stack current was measured using two split-core current transducers (CR Magnetics CR5220S Split Core Current Transducers) rated for 0-300 amps DC. Verification on the current reading was accomplished intermittently with a Fluke split-core current transformer (Fluke i410 AC/DC Current Clamp). Hydrogen gas mass flow from the system to the end process was measured using a Sierra Instruments 840H Hi-Trak Mass Flow Controller. 4-20 mA analog output logic from the split-core current transducers and mass flow controller was logged on a Dent DataLogger Pro.

All Dent power meters and the Dent data logger are read from by way of an USB-RS232 adapter at regular intervals depending on their memory capacity. The Dent data logger is connected at all times during system operation so that real-time hydrogen flow and current throughput data can be accessed for diagnostic purposes.

3.1.6 Chiller System

The C10 electrolyzer system has three water cooling loops that serve heat exchangers with the electrolysis process DI water, the hydrogen gas before the drying process, and the blowers in the power electronics cabinet. The cooling demand is served by a co-located chiller system, shown below in. The net cooling water requirement of the C10 is a max heat load of 114,307 Btu/hr, at a flow rate 90 L/min at 3 barg. The chiller system used is an Accuchiller® air-cooled chiller (PN#: NQA13C1E213C) which provides up to 190,000 Btu/hr.

3.1.7 External DI Water Purification System

A deionized water polishing system was implemented to upgrade municipal water supply from the Irvine Ranch Water District (IRWD) to a high-quality DI water stream. This was accomplished through service deionization provided by Evoqua Water Technologies. The skid is comprised of a 4 ft^3 water softener, followed by two 3.6 ft^3 mixed bed deionizer tanks rated for 36 LPM.

The expected service life of such a system is 2000 gallons of delivered DI water. For the C10 consumption rate of the system, this would give a replacement cycle of ~35 days or roughly a monthly filter exchange on mixed bed deionizer tanks. Two mitigating factors led to a replacement cycle of every 10-14 days for the DI water system.

Much of the IRWD water delivered comes from groundwater sources, which leads to measured hardness values as high as 394 mg $CaCO_3$/Liter [66]. The US Geological Survey (USGS) defines hardness values higher than 250 mg $CaCO_3$/Liter as ‘very hard’ [67]. This has a direct impact on the longevity of ion exchange-based resin filters, as the total amount of ions removed per liter of water delivered is much higher than what is typically expected. The water softener bed does assist in mitigating the high hardness of the water by removing problematic cations such as Iron (Fe^{2+} and Fe^{3+}), however it does so by exchange with salts that will still need to be removed by the downstream deionizer beds and as such does not ultimately reduce the ‘work’ done by the DI beds.

Due to the relatively low DI water consumption rate of the C10 system, the system only 'fills' from the DI water feed intermittently. At full load conditions, this fill occurs every ~3 hours and fills for about 3 minutes. Resin-based ion exchanger beds are rated for specific flow ranges at a constant flow. When there is a non-constant flow, or the flow rate is too low, the resin beds can lose their compaction, allowing some water to flow through 'channels' bypassing the resin. This 'channeling' event effectively reduces the overall capacity of the tanks. Oftentimes, these drawbacks are prevented by implementing a recirculation pump in the DI system. To keep system complexity down, a water bleed line was introduced to keep a constant flow through the beds.

3.1.8 Mass Flow Controller & Control System

To control the dispatch of the C10 system for dynamic response, a mass flow controller was installed on the hydrogen product line. The mass flow controller is able to dispatch the electrolyzer system by choking the hydrogen flow, simulating a reduced hydrogen demand downstream of the system. The pressure feedback loop in the hydrogen management subsystem senses the higher downstream pressure and reduces the current throughput to the electrolysis stack accordingly.

For dynamic dispatch, a dispatch profile from a selected data source, or a general load profile such as a stepwise ramp, is converted to comma-separated (.csv) file format. The .csv file is read by a Python script, which outputs the signal value through serial communication to a Seeed Studio Seeeduino microcontroller. The microcontroller reads the serial value and then outputs an equivalent 0-5V DC analog signal through pulse width modulation. This signal is converted to a 4-20mA signal by way of a signal conditioning circuit comprised of an RC circuit for conditioning the Volts DC signal which then goes through a Texas Instruments XTR110 precision Voltage-to-Current converter IC. This 4-20mA signal is then communicated to the mass flow controller which controls the hydrogen flow from the system.

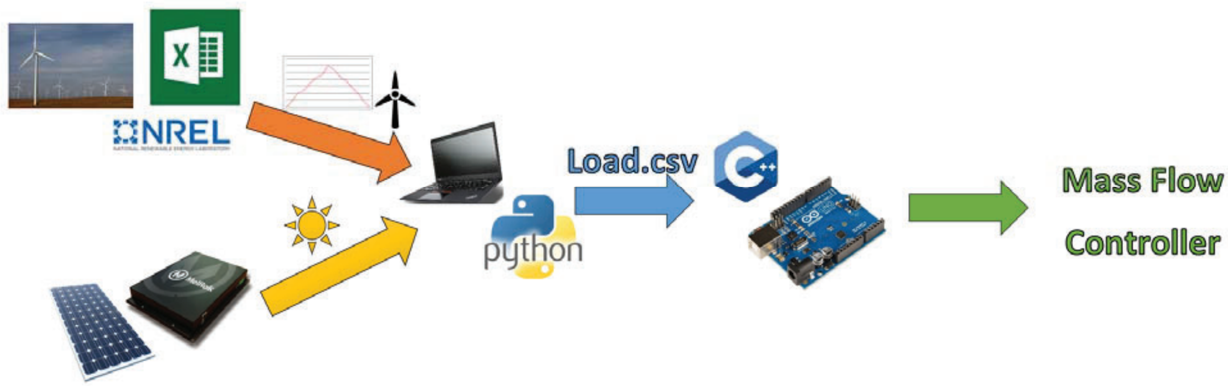


Figure 8. Dynamic dispatch control of the mass flow controller.

Hydrogen mass flow was measured and controlled using Sierra Instruments Hi-Trak 840H mass flow controllers (P/N#: 840H-4-OV1-SV1-D-V4-S4-HP). Two separate mass flow controllers (MFC) were employed throughout the duration of testing. Both MFCs were the same model, with separate factory calibrations set for 0-10 SCFM H_2 and 0-10 SCFM carbon monoxide (CO). Initially, the MFC calibrated for hydrogen gas was used, but a critical failure of the valve spring adjustment screw took the MFC out of service. While that MFC was being repaired, the CO configured flow controller was put into service. Before flow controllers were put into service, an in-situ calibration was performed using a laminar flow element (Meriam: Model 50MJI-6410). The calibrations for the two mass flow controllers are shown below in Figure 9.

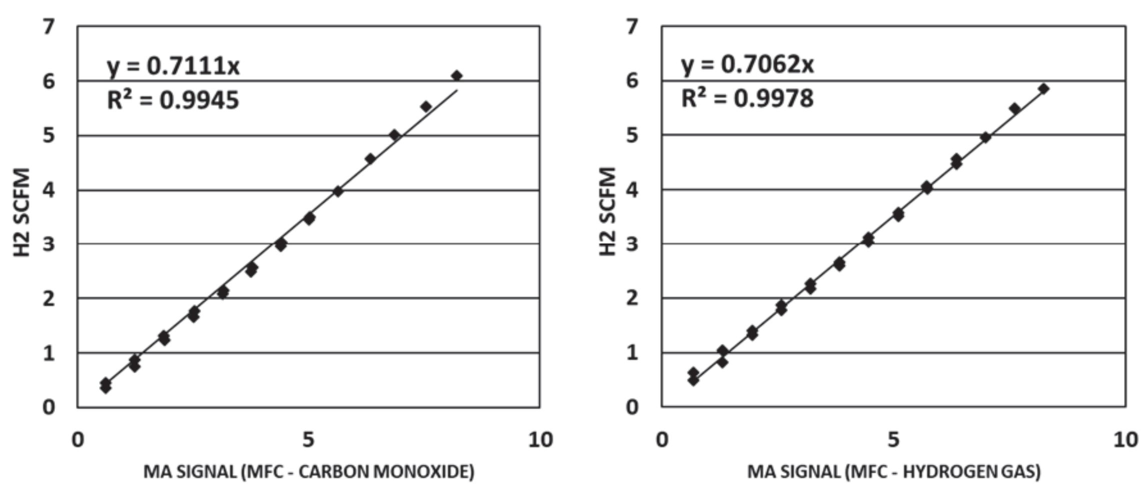


Figure 9. Calibration curves for the two mass flow controllers using a laminar flow element.

3.1.9 UC Irvine Microgrid & Melrok Metering Network - MSTB PV Array

The UC Irvine microgrid is centrally operated by a central UCI substation that serves a 12kV circuit, which radially distributes electrical power throughout the campus. The substation is connected by a 66kV circuit to the nearby Edison MacArthur substation. Major sources of electrical generation resources on the microgrid include the 18 MW UC Irvine Central Plant, 4 MW of rooftop solar photovoltaic, as well as a 250kW Amonix tracking solar photovoltaic array. An extensive network of power meters throughout the UCI microgrid provides real-time and historic data concerning electricity consumption and production on almost three quarters of UCI's buildings and on all generation assets. For the purposes of this study, the rooftop photovoltaic array located on the roof of the Multipurpose Science and Technology Building (MSTB) was chosen as source for the solar load following dispatch profiles. This is due to the relatively high temporal resolution of the available historical data (1 min time-step) and the scale of the array (75 kW standard testing conditions - STC) being comparable to the 60kW electrolyzer system. Melrok's Energistream™ software was used to search through and obtain the historical data.

3.1.10 Natural Gas Pipeline & Gas Turbine

The hydrogen from the electrolyzer system is fed into a natural gas bypass line located at the Central Plant's external natural gas compressor skid. The hydrogen 'injection' line is 70' of 3/8" OD SS316 tube that connects to a ½" NPT access port on the 4" iron pipe bypass line. A stainless-steel check valve was put in place to prevent any backflow of natural gas from the bypass line to the hydrogen injection line. The hydrogen injection line is shown in Figure 10.

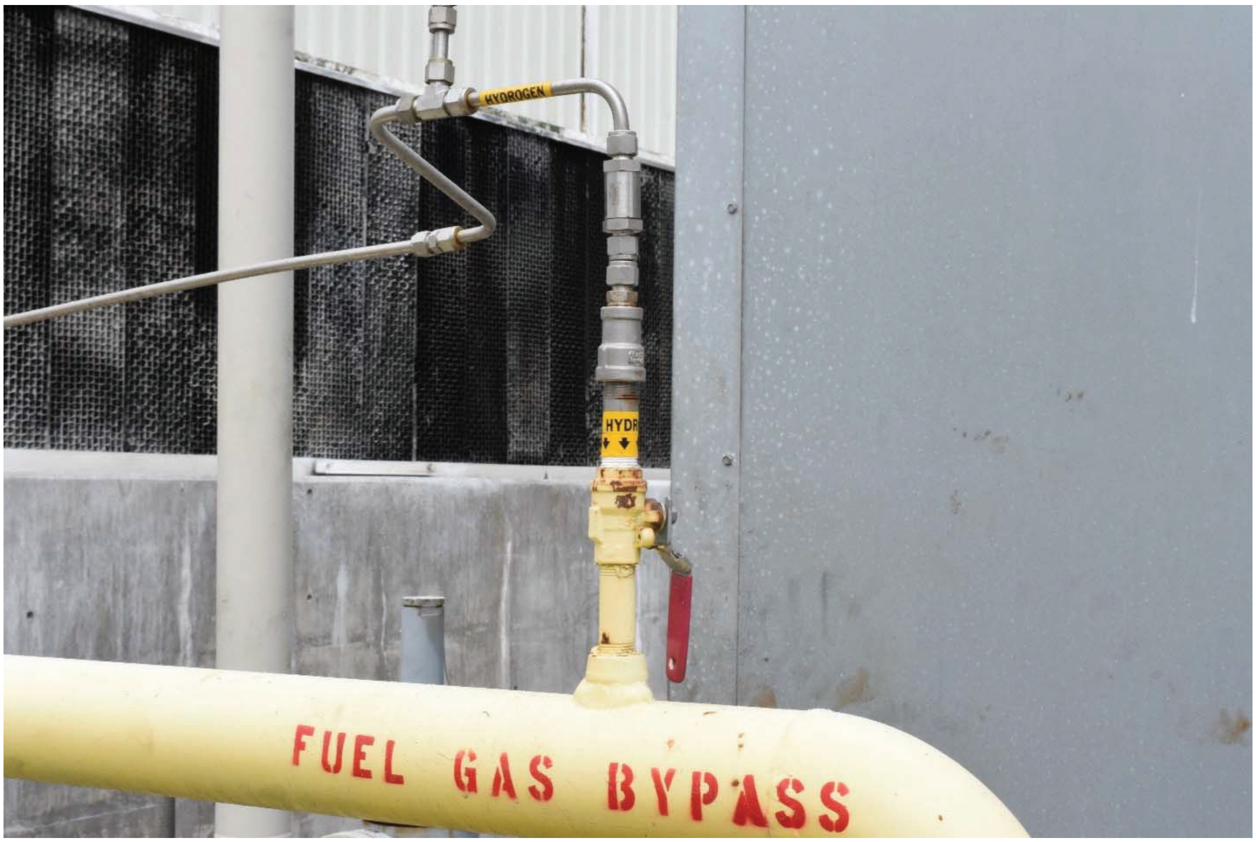


Figure 10. Hydrogen injection line at UCI Central Plant

The pressure of the natural gas delivered by Southern California Gas Company (SCG) to the Central Plant line varies as much as 20 barg up to 34.5 barg, though typically varies in a range between 26 to 27.5 barg. When the line pressure drops below 25 barg, the external gas compressor kicks on, boosting the pressure to at least 30 barg.

3.2 Results & Discussion

3.2.1 Electrolyzer Steady State Operation & Benchmarking

For the first 1000 hours of operation at the demonstration site, the C10 electrolyzer system was operated at full throughput to establish baseline operation characteristics and performance. Total system power consumption, stack power consumption, and the production of hydrogen before and after the drying process was analyzed and compared at 100, 600, and 1000 hours of operation.

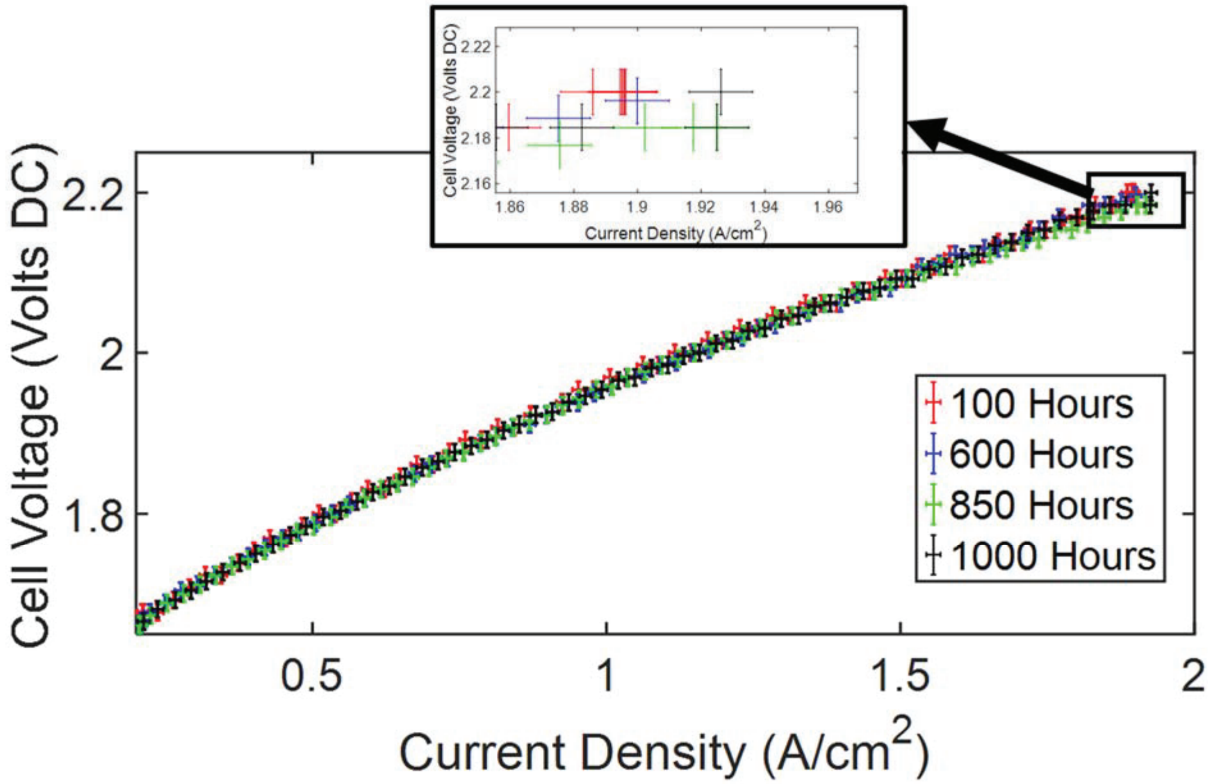


Figure 11. Start-up j-V curves during 'break-in' period with measurement error bars.

Figure 11 demonstrates the slight variations observed in the measured j-V values outside of the rated error of our current and voltage sensors, specifically current density. These curves were generated at the same average feed water temperature and stack pressures, highlighting a 'break-in' period for stack performance that occurred within the first 800 hours. After 800 hours, a consistent maximum current density of approximately 1.93 A/cm^2 was established. At 600 hours of operation, the AC/DC power supply failed, and was replaced by the OEM with a new power supply. No immediate notable change in maximum current density and general j-V behavior was observed on replacement of the power supply, suggesting that the 'break-in' period was not related to the power supply and rather due to changes in the stack. In PEM electrolyzers, the membrane electrode assembly (MEA) typically undergoes an activation process immediately after manufacturing that can last anywhere from several hours to several days, resulting in progressively better cell performance that ultimately plateaus [68]. Generally, 'break-in' periods are more commonly observed in studies of high temperature proton exchange membranes for application in phosphoric acid fuel cells (PAFC) and direct methanol fuel cells (DMFC) [69] [70], but are not unheard of for PEM fuel cell MEAs [71] [72]. An increase in current density without an increase in applied potential is typical of these 'break in' or activation processes, which involve cycling of the cell [73].

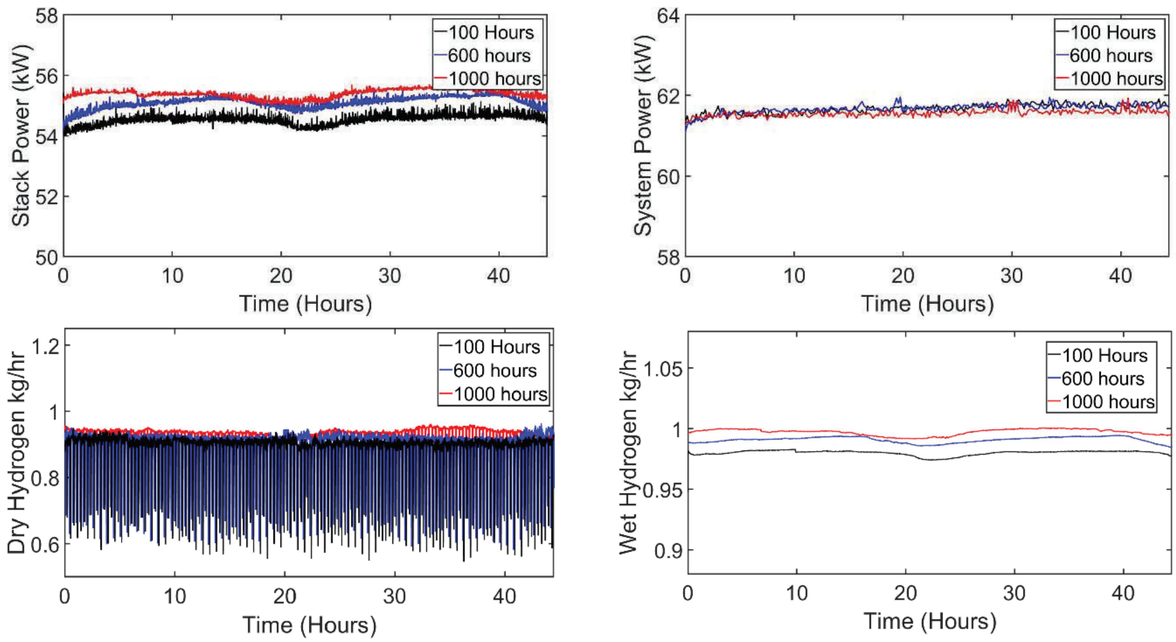


Figure 12. Stack power, system power, and hydrogen production pre- and post-drying process across different stages of steady state characterization of the electrolyzer system.

Figure 12 demonstrates the slight variation in system operation across the first 1000 hours of operation for three separate periods of continuous two-day operation. The constant dips observed in post-dryer hydrogen output is due to the swing-bed operation of the PSA dryer system, while a generally 'unsteady' flow rate is observed related to the pressure regulation manifold managing the hydrogen pressures on the system and 'product' (downstream of the electrolyzer) sides. Measured stack power consumption and dry hydrogen production increased over the test period as a direct result of the increase in maximum current density. Wet hydrogen production also increased, and is a quantity derived directly from measured stack current using the mol balance of electrons to hydrogen gas. The calculation is shown below in equation *(1)* where F is the Faraday constant, n is the number of cells in the stack, M_{H2} is the molar mass of hydrogen, and $\eta_{Faraday}$ is the Faradaic efficiency. Faradaic efficiency is the ratio of current that participates in the production of hydrogen to the total amount of current delivered to the stack. This quantity reflects the magnitude of parasitic losses in the stack, due to either leakage and crossover of species or short circuits. It is often assumed to have a value of 0.99 [48] [74], or ignored all together [46] [75]. As the total amount of hydrogen lost consists of losses to the PSA dryer system as well as cross-over losses in the stack, case we neglected this loss term ($\eta_{Faraday}$ = 1) for now and just calculate the maximum expected hydrogen throughput. In section 4.2, actual faradaic efficiency is estimated from measurements and can be seen to vary depending on current density and operating pressure.

$$\mathrm{H}_{2,\mathrm{Wet}}[gram/sec] = \frac{\mathrm{I}_{\mathrm{Stack}}}{2\mathrm{F}}\mathrm{n}\mathrm{M}_{\mathrm{H2}}\eta_{\mathrm{Faraday}} \tag{1}$$

System level power consumption did not increase relative to the increases observed in stack power consumption and hydrogen output, resulting in an increasing improvement in system efficiency as the electrolyzer was exercised in these first 1000 hours of operation. A diurnal trend is apparent in stack power consumption as well as hydrogen production, and absent in system power consumption. The time of day at which the minimum and maximum of this trend occurs is midday and midnight respectively, meaning that system efficiency varies an observable amount with the time of day. The maximum system efficiency was typically observed near midnight and the minimum was observed near midday, most likely due to the ambient temperature variations associated with these times of day. Highest efficiency was correlated with lowest ambient temperature.

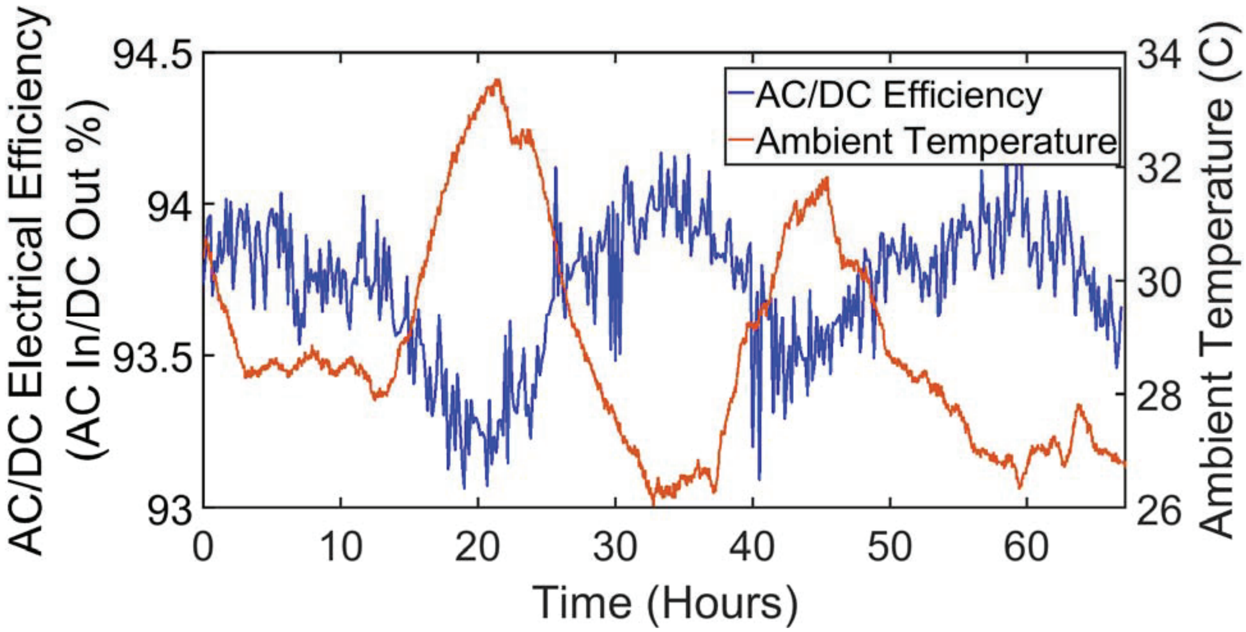


Figure 13. AC/DC power electronics efficiency and ambient temperature over two and a half days at full throughput.

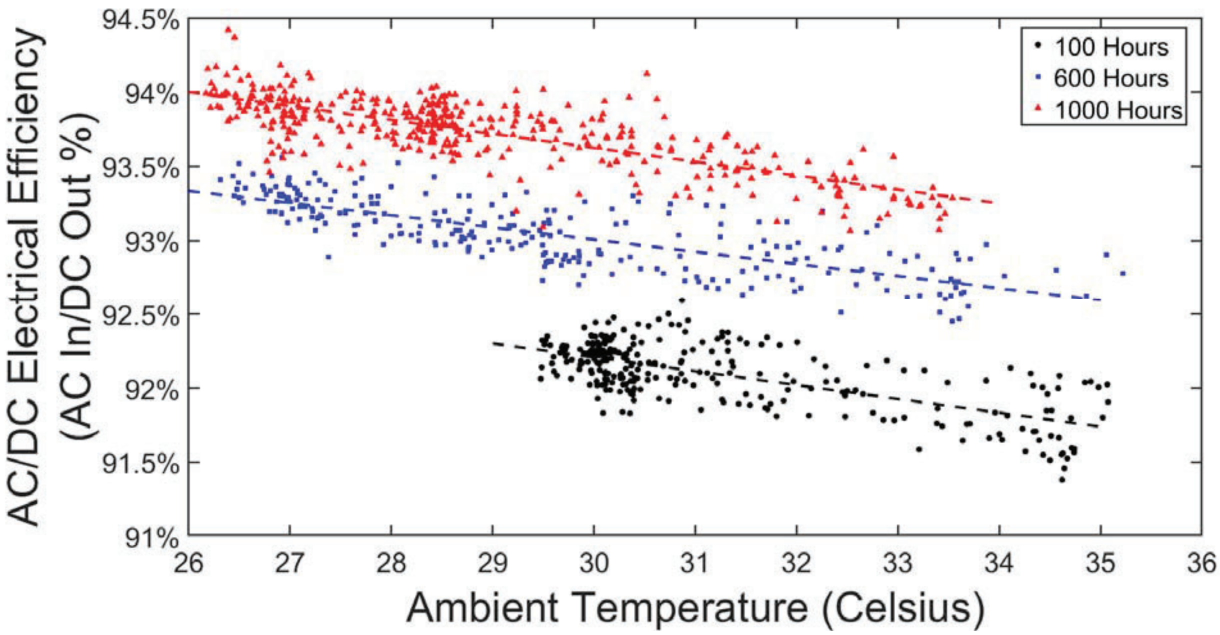


Figure 14. AC/DC power electronics efficiency vs. ambient temperature across the benchmarking test period.

The reoccurring diurnal trend points in system efficiency and maximum stack throughput points to a potential correlation in ambient temperatures and the efficiency of the AC/DC power electronics. The inverse correlation between ambient temperature and efficiency is shown above at the ~1000 hours of operation mark for a two and a half day run in Figure 13. The correlation with ambient temperature does not entirely account for the increased output from the AC/DC power electronics; Figure 14 shows a clear improvement in efficiency as test hours progressed for a given ambient temperature. The overall negative correlation in power electronics efficiency with ambient temperature still holds. This could be the result of power output derating, where the amount of power dissipation lost in the form of heat in AC/DC rectifier power supplies increases as ambient temperature increases [76] [77].

The correlation between AC/DC power supply efficiency and low ambient temperatures assists in explaining the variation in operating current observed post 'break-in' period of operation. Across the first 800 hours of operation, a steady climb in DC current output to the stack was observed during this "break-in period." For the remainder of the operation period (1000 - 4000 hours of operation), the maximum observed operating current for a given day of continuous operation varied within a consistent range (see Figure 15). The correlation between AC/DC power electronics and ambient temperature (Figure 14) holds as well for this variation in maximum stack current past the 'break-in' period (Figure 16).

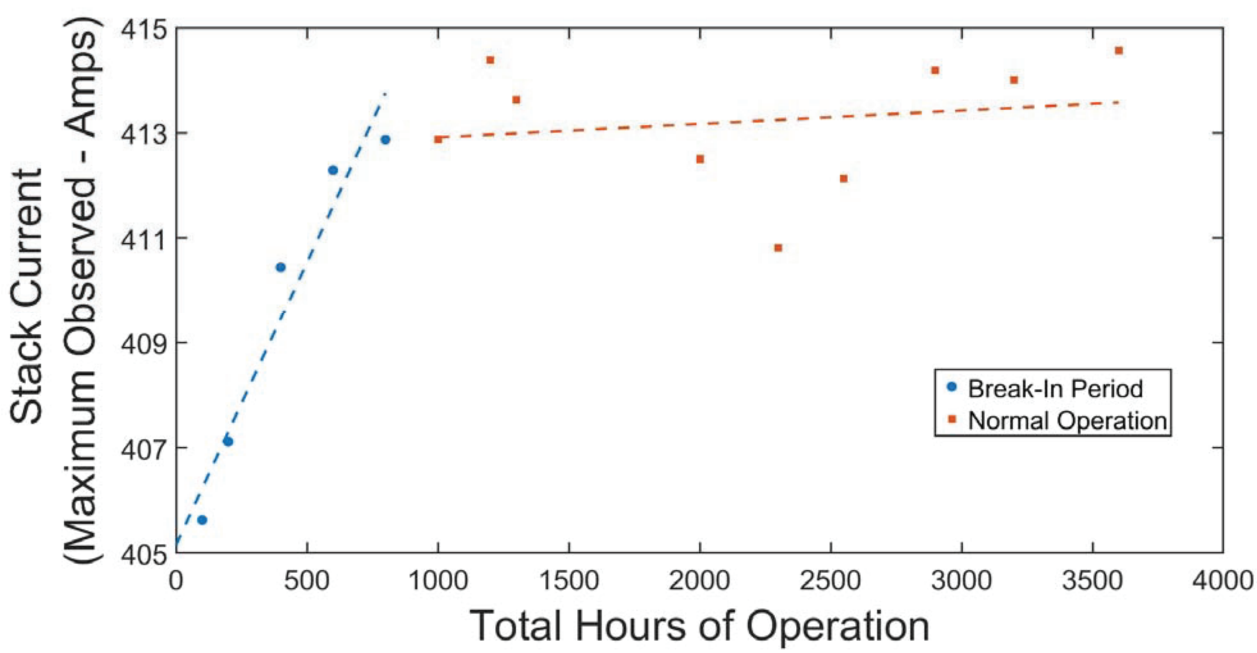


Figure 15. Maximum observed stack current on a given day versus net hours of operation on the electrolyzer system, break-in period observed in the first 800 hours.

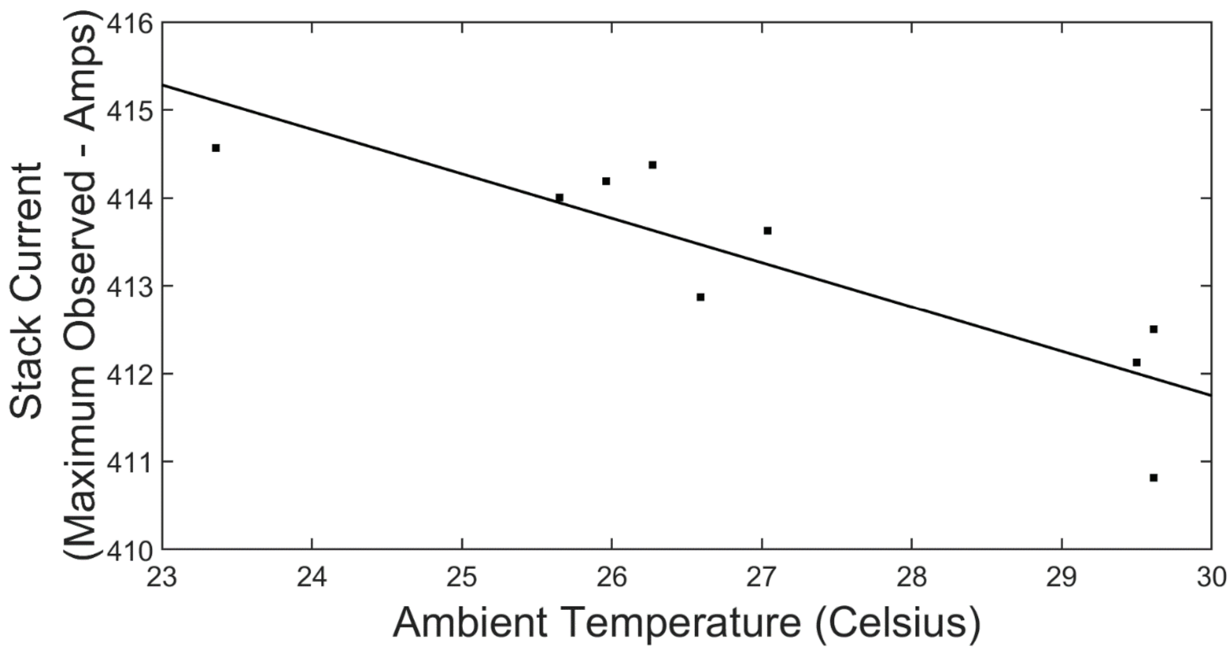


Figure 16. Maximum observed stack current on a given day versus ambient temperature for 'normal operation' data in Figure 15 (above).

The power consumption of the air-cooled chiller that provided the thermal management for the electrolyzer system was monitored for the duration of the benchmarking tests. The full power consumption of the electrolyzer system including the power demand of the chiller is shown below for the 100- and 600-hour operating cases. Figure 17 shows the energy 'steps' leading to the ultimate product of hydrogen gas, allowing insight into the relative magnitude of electrical energy loss. The 1000-hour case is not included as the power meter associated with the chiller failed around the ~800 operating hours mark. As the power consumption of the chiller was not of major interest to this study, the meter was not replaced.

The magnitude of energy consumption that goes to the chiller is more than twice the amount lost to the rest of the balance of plant, including power electronics. In terms of hydrogen production, a quarter of the electricity consumption is directed to the chiller system, equivalent to 17 kWh of electricity per kg of hydrogen produced.

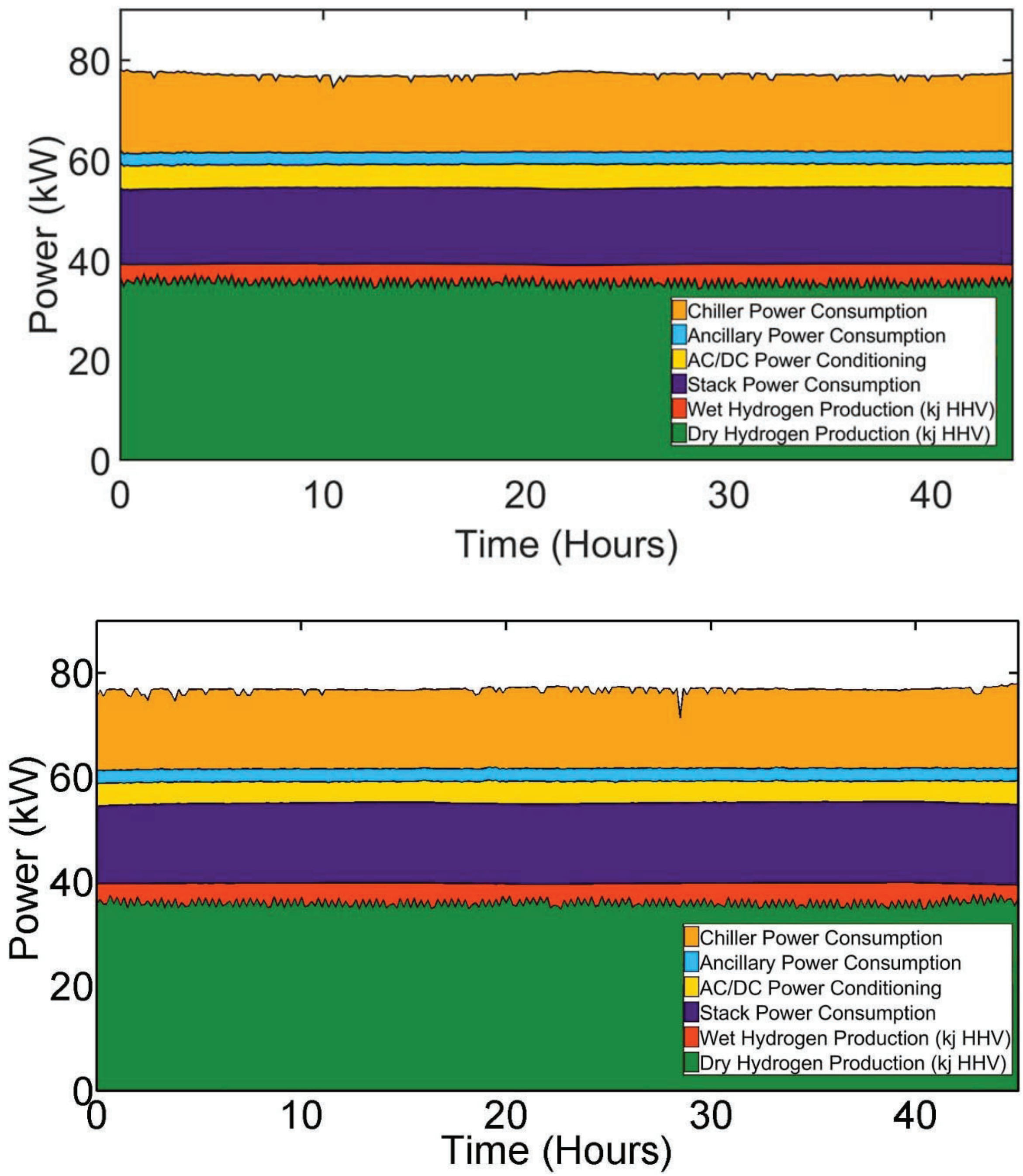


Figure 17. Energy consumption at the 100 hours of operation regime (Top) and 600 hours of operation regime (Bottom).

The rated water consumption is given as ‘roughly’ 2.4 gallons per hour at full output. For molar balance alone, the electrolysis reaction would consume 2.37 gallons per hour at the rated current of 410 Amps. The OEM’s rated water consumption does not seem to account for other sources of water loss. For widespread implementation of electrolyzer technology, it is important to consider the total water consumption of these systems.

The water consumption of the system at full throughput was determined by analyzing the fluctuations in water level in the A500 primary feed water tank over time. The A500 tank is not part of the recirculating DI water loop, and only intermittently fills to the A300 water tank that is part of the stack water loop. The A500 serves as a buffer tank that ensures the system always has an excess of DI water available. A float-based level switch system maintains the water level between two states, opening a feed water inlet valve when the level switch reaches an 'L1' level state and closing the valve once an 'L3' level state is reached.

Due to the intermittent nature of the transfer of DI water from the A500 buffer tank to the recirculating DI water loop, it is rare that the filling of the A500 tank coincides with the outflow of water from the A500. Using this fact, in conjunction with the dimensions of the A500 tank and the height change in water level going from L1 to L3, the amount of water added to the A500 tank during each fill event is determined as 9.85 gallons of DI water.

Using only the fill events where no other flows of water occurred, the average flow rate of water from the external DI water system to the A500 is found to be 1.602 gallons per minute. Using valve state data, net water consumption of the electrolyzer system (not including the chiller) was found for the 100-,600-, and 1000- hours of operation for full throughput operation. Actual water consumption was approximately 3.1 gallons per hour for full throughput across all cases.

Table 2. Summary of full throughput benchmarking on electrolyzer system.

	Run 1 100 Hours	Run 2 600 Hours	Run 3 1000 Hours
Avg. H2 (kg/hr)	0.899	0.912	0.936
Avg. Current (Amps)	401.52	407.99	411.30
Avg. Water Consumption (Gal/hr)	3.095	3.031	3.116
Avg. Stack Power (kW)	54.54	55.09	55.38
Avg. System Power (kW)	61.67	61.68	61.56
H2 Dryer Efficiency (%)	90.85%	90.49%	92.24%
AC/DC Efficiency (%)	92.09%	93.03%	93.69%
Stack Efficiency (%HHV H2)	72.03%	72.06%	72.17%
System Efficiency (%HHV H2)	57.47%	58.25%	59.88%
System Efficiency w/ Chiller (%HHV H2)	45.99%	46.79%	N/A

Table 2 summarizes the results of key parameters for benchmarking of the electrolyzer system performance and maximum load condition. Overall system performance increased as testing went on. The increase in current output from the AC/DC power electronics lead to a proportional increase in hydrogen output, improving efficiency across the board. Water consumption did not vary a significant amount. The values obtained provide a reference of expected system performance when operating as intended for a commercial electrolyzer system as opposed to the modified dispatch approach explored in the following sections.

3.2.2 Electrolyzer Sustained Part Load Performance Characterization

A step-wise ramping load profile was employed to study sustained part load performance. These tests held the electrolyzer's hydrogen output at a fixed amount in one-hour intervals, establishing a steady-state part load condition in the electrolyzer system as it load follows the hydrogen 'demand' downstream, allowing for the characterization of the electrolyzer's performance and the control scheme's efficacy in modulating electrolyzer power consumption. The control signal profile and observed system response in kg of hydrogen produced per hour averaged over 15-second- and 10-minute intervals, total system power consumption averaged over 2-minute and 10-minute intervals, and instantaneous stack current measured on 1-second intervals are shown below in Figure 18. The dramatic swings in flow that are characteristic of the transfer of pressure from the active PSA dryer bed to the other are absent below the 0.6 kg/hr mark (65% of full output). The unsteady flow characteristic of the full throughput operation begins to appear at the 0.88 kg/hr output set point (95% of full output) but is not fully in effect until the 100% set point, when the flow controller is fully opened. Observing the 10-minute averages for the measured flow rate, it is clear that the unsteady flow occurs as the average flow rate drops below the flow set point on the flow controller, with the effect becoming more pronounced as the disparity increases.

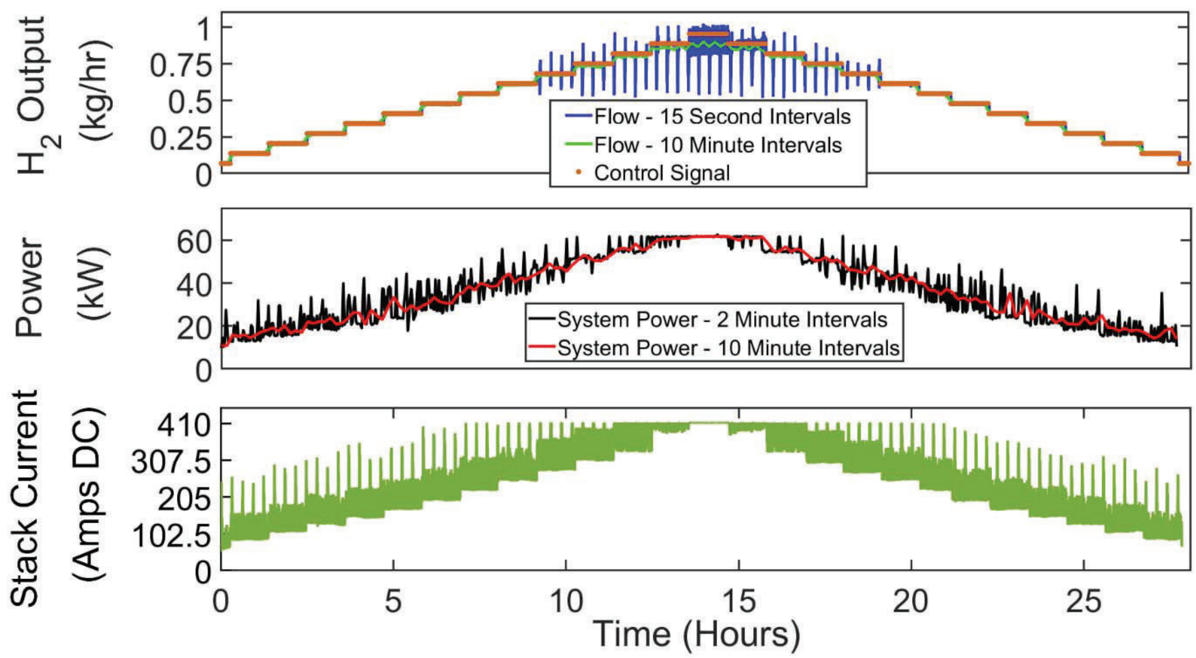


Figure 18. Step-wise ramp of electrolyzer system net hydrogen production vs. control signal.

Of particular interest is the efficacy of the mass flow controller in controlling the system power consumption. From a 2-minute averaged perspective, system power consumption is fairly erratic. On a 10-minute average basis, system power consumption begins to match the desired stepwise profile, however there are still visible undesirable transients. The reason behind these transients can be observed in the stack current behavior. The dramatic, evenly spaced spikes in current correspond to the switching of dryer beds in the PSA system and is present across all load conditions. The timer-based dryer operation is not modified by the load condition of the electrolyzer as the hydrogen output does ramp up to pressurize the new bed and purge the bed being regenerated. The more consistent and lower magnitude current fluctuations occur as a result of the purge cycle for the 'A300' hydrogen-water phase separator, where hydrogen throughput is temporarily increased to maintain pressure as the water is drained. All transients in stack current and by extension net power consumption can be traced to system control's driven by hydrogen throughput, specifically concerned with hydrogen drying.

The efficacy of the mass flow controller in dispatching the system in a load following manner was assessed during the sustained part load testing. Figure 19 outlines response in system power consumption as a function of flow controller control signal. The flow controller results in a linear response in system power consumption on average, with a non-linearity occurring from the 0.41 to 0.48 kg/hr H_2 set point. This non-linearity characterizes when the electrolyzer system begins to see higher pressures downstream (choking from the flow controller) than the system pressure. Additionally, the actual power consumption still varied appreciably from the average by a few kW, and the full range of observed power consumption is very large due to the erratic stack current ramping.

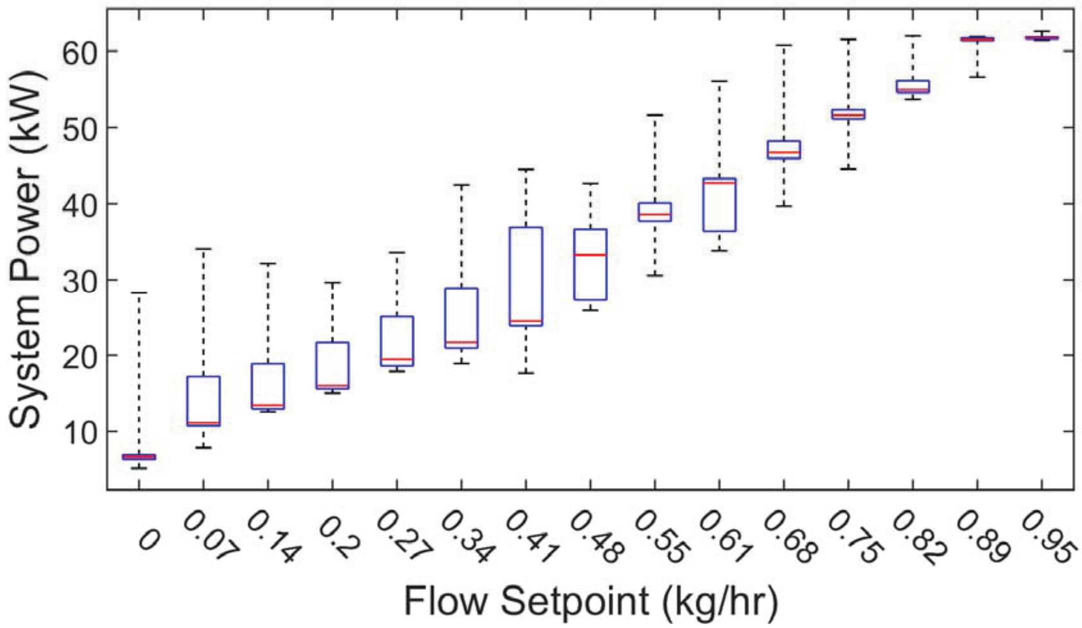


Figure 19. Box plot of system power consumption dispatch versus flow controller signal. Red bars show the average value, with 95% confidence intervals in blue, and the entire range of observed responses in black.

3.2.3 VRES Load Following – Solar Photovoltaic Array

Figure 20 displays the historical generation data from the MSTB photovoltaic array utilized in the electrolyzer solar load following tests concerning the seasonal variations in output from a solar PV resource.

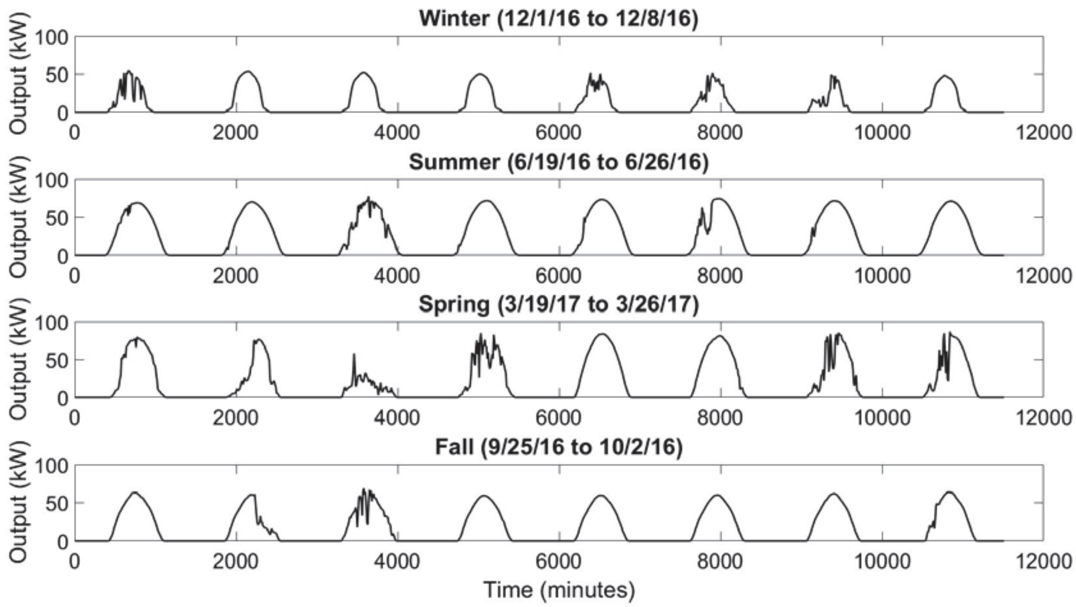


Figure 20. MSTB Rooftop Solar Photovoltaic Array Output – Seasonal Variation

The selected solar profiles demonstrate many of the expected changes in output of a fixed solar photovoltaic system due to seasonal and weather variations in the southern California region. The highest capacity factors of the system are experienced in the summer and spring, the lowest in the winter. Greater intermittency is experienced in the spring and winter when weather events such as rain and cloud cover are more common. The highest peak outputs are observed in the spring, due to the confluence of high solar irradiation giving greater throughput with lower ambient temperatures resulting in a higher PV module efficiency. Figure 21 highlights this season to season variation for clear days exhibiting the typical diurnal solar generation patterns.

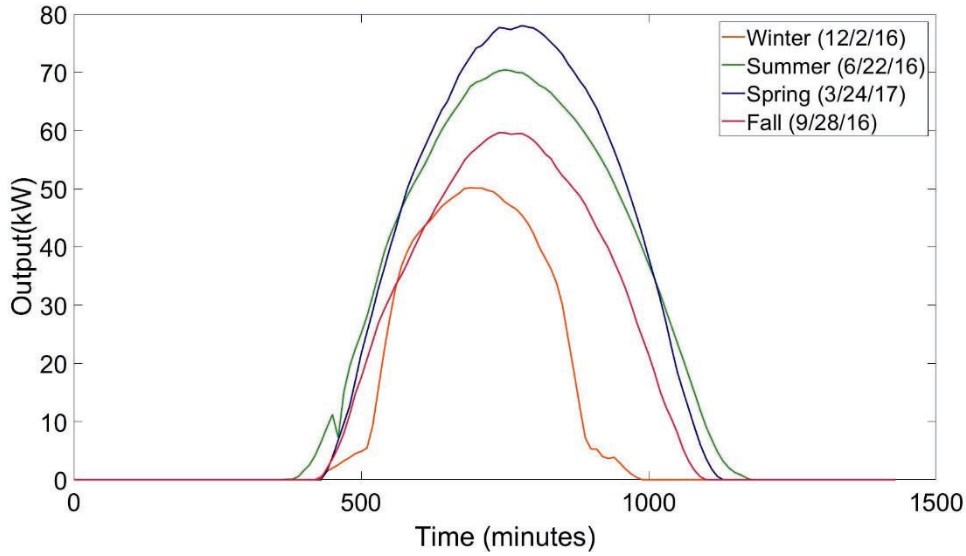


Figure 21. Seasonal differences in output from MSTB solar PV array for relatively 'clear' days.

For purposes of expedience, solar 'downtime' (ie; nighttime) was cut from the control signal sent to the electrolyzer system for these tests. The winter and spring PV cases were the first two solar PV load following runs accomplished and were accomplished successively. These two cases provide the two 'extremes' for comparison in capacity factor and transient weather effects. Figure 22 and Figure 23 below show the hydrogen output response and the system power consumption for the two runs respectively. In both cases the hydrogen flow controller was able to follow the dynamics effectively (Figure 22). From the system power consumption perspective, there were two points in the spring case where the extreme transience in the control signal was not effectively matched by the system (Figure 23). This occurred on each occasion on a down-ramp event, specifically for a local minima or 'valley'. In each case electrolyzer system did not reduce its power consumption low enough to match the signal.

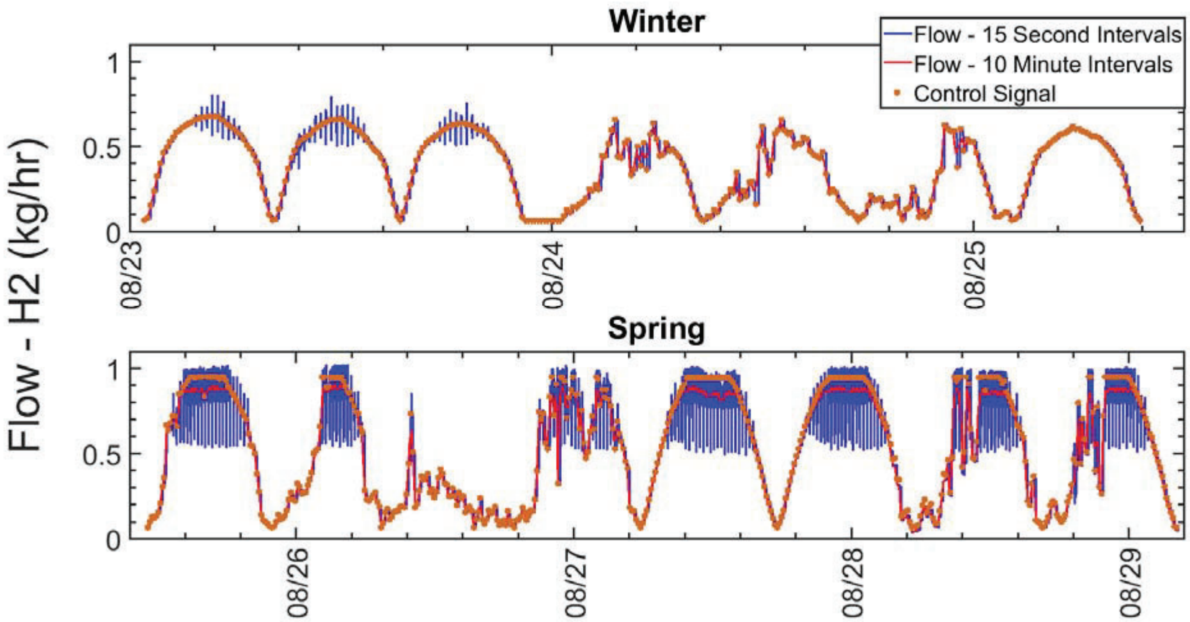


Figure 22. Hydrogen flow control signal vs. hydrogen flow output for winter (top) and spring (bottom) solar PV load following test.

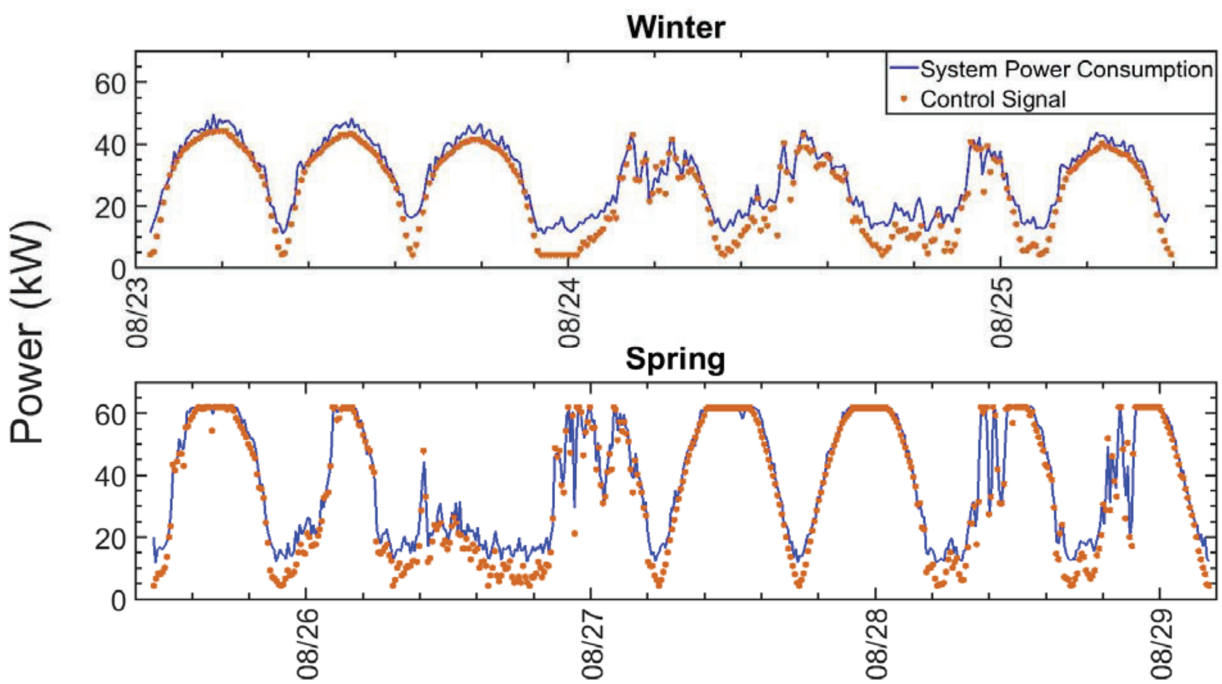


Figure 23. System power consumption control signal vs. measured power consumption for winter (top) and spring (bottom) solar PV load following test.

Both the summer and fall PV load following cases ran into issues that made them incomplete to an extent. The results of the most successful runs for these two cases still provided valuable information for the load following studies and are included below. The fall solar PV load following case was accomplished two weeks following the winter and spring cases. Testing was interrupted by drift in the valve spring tension on the mass flow controller, requiring disassembly and multiple readjustments of the spring tension. As a result of these adjustments, the fall run was a ‘special case’ in terms of the minimum load conditions that could be reached. The upside of this was an overall increased range in hydrogen output and power consumption, which reached minimums of 0.029 kg/hr and 6.6 kW respectively. The downside of this was lower reliability, as operation at lower and lower hydrogen flow rates led to an increased risk of the valve closing entirely.

One of these zero flow events did occur in the fall run (Figure 24), resulting in an increasingly dramatic departure from the load following signal. The valve does not open again with increasing flow signals until the electrolyzer starts sending the appropriate hydrogen flow through the pressure regulation manifold, which may not readily occur in the event of low-pressure differential from the flow controller outlet to the natural gas injection point. An integration of the flow controller into the electrolyzer system controls could easily circumvent this issue, but due to the ‘external’ control approach employed here, the flow controller required regular and careful adjustment to avoid these events.

The fall season did encounter some transients that proved challenging from a power consumption control perspective, similar to what was observed in the spring case, but to a lesser extreme.

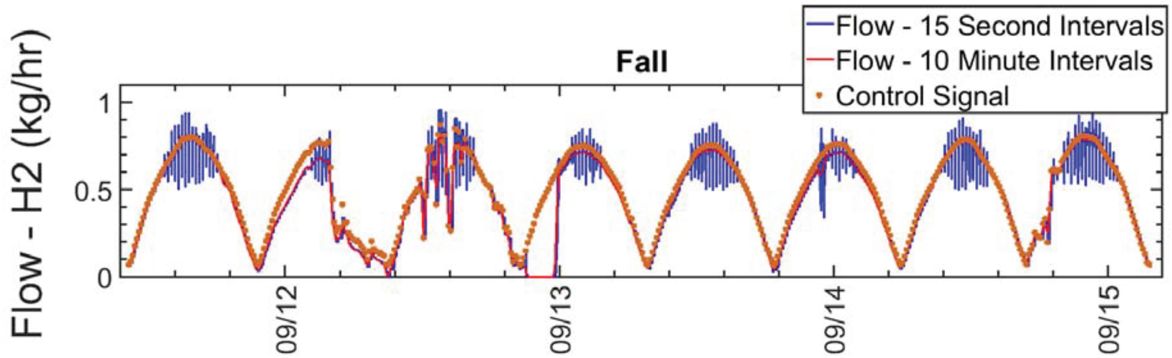


Figure 24. Hydrogen flow control signal vs. hydrogen flow output for fall solar PV load following test.

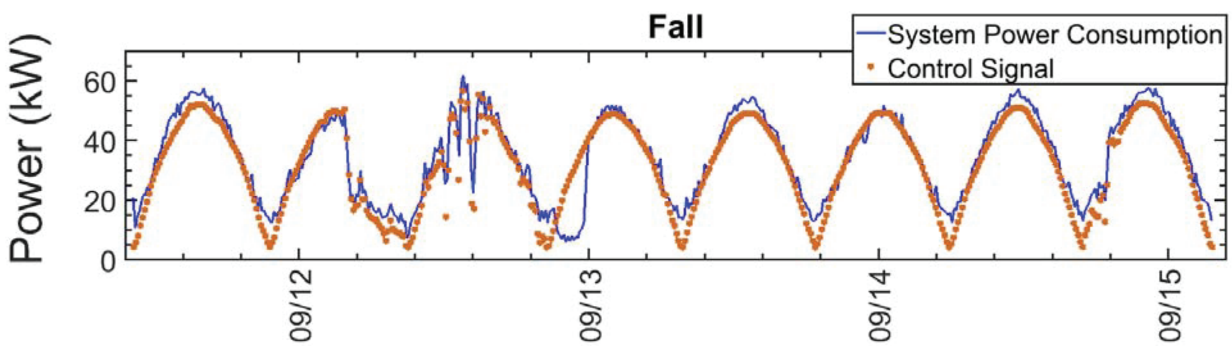


Figure 25. System power consumption control signal vs. measured power consumption for fall solar PV load following test.

The summer PV load following was completed successfully but was broken up into three parts due to similar flow controller issues experienced during the fall solar PV load following test. The flow controller valve assembly was rebuilt with a new valve spring and adjustment screw on October 15, 2017 and flow controller issues were largely taken care of, except for some initial re-adjustments.

Flow and system power consumption response for the summer case is displayed below in figures Figure 26 and Figure 27. For the most part, the transients in load following in summer are relatively smooth.

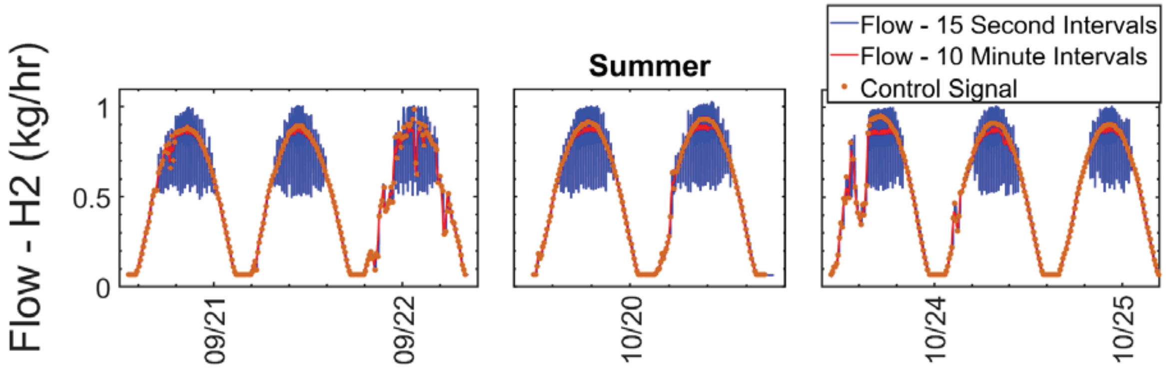


Figure 26. Hydrogen flow control signal vs. hydrogen flow output for summer solar PV load following test.

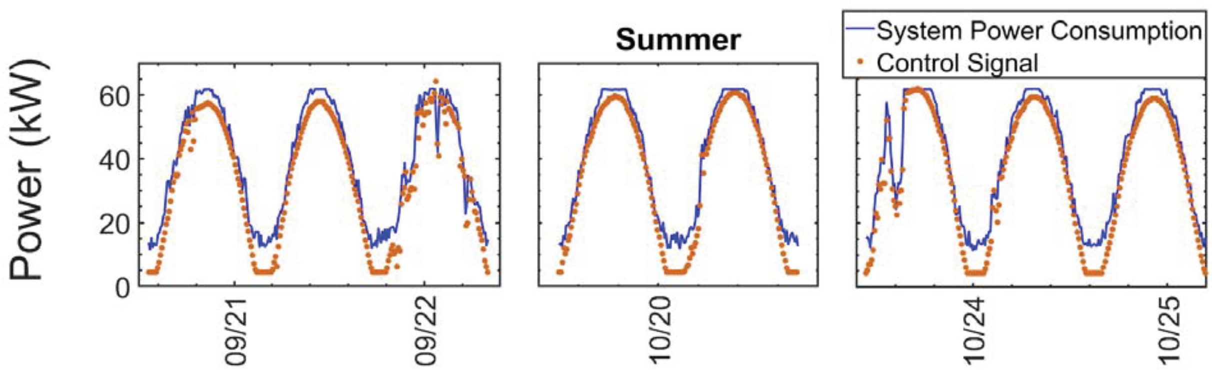


Figure 27. System power consumption control signal vs. measured power consumption for summer solar PV load following test.

Table 3 below summarizes the results of interest with respect to the seasonal differences. Included below is both the capacity factor of the system as the tests were run (zero downtime due to lack of solar radiation at night) and including the down time. The latter result serves to highlight an issue encountered by many energy storage strategies when being paired with solar PV systems, low capacity factors. To maximize the electricity arbitrage capabilities of the energy storage system and prevent curtailment from the PV system, the power capacity of the energy storage system is typically sized close to the peak over-generation of the PV system. With a peak power capacity of 75kW on the PV system and 62 kW on the electrolyzer system, the two systems are relatively well matched. The result is a capacity factor of at most 38.07% during peak solar activity in the summer season, and as low as 15.89% in the winter.

An encouraging result is the consistent overall system efficiency for all cases in the range of 51-53% higher heating value basis. In retrospect this is perhaps not surprising; system efficiency was observed to remain relatively flat with decreasing load condition until around 40% and below. In all cases, the total capacity factor of each run, considering only actual operating hours ('Test Only' - Table 3), was well above this number, meaning that the system typically operated in the optimal system efficiency regime of greater than 40% load condition.

Table 3. Seasonal comparison for results of solar photovoltaic load following tests.

	Winter	Spring	Fall	Summer
Capacity Factor -Test Only (%System Power Consumption)	47.25%	62.49%	55.88%	63.48%
Capacity Factor - Overall (%System Power Consumption)	15.89%	28.97%	26.05%	38.07%
Hydrogen production (Average kg/day)	3.10	5.75	5.03	7.39
System Efficiency (%HHV H2)	51.60%	52.55%	51.08%	51.37%
Stack Efficiency (%HHV H2)	77.70%	73.92%	75.53%	73.92%
Maximum Slew Rate Up/Down - Stack (kW/sec)	40.81/ -54.53	45.86/ -55.15	41.85/ -54.74	45.14/ -54.74

Also of interest is the extremity of power transients that the electrolyzer is subjected to when load following solar PV dynamics. Due to limitations in sampling rate for the system power consumption metering, and combined with the fact that the stack accounts for the entirety of the variable power consumption (barring very slight variation in losses to the AC/DC power electronics), the maximum slew rates are defined in Table 3 in terms of stack power change on a second to second basis. The maximum up ramp rates varied slightly, with the higher capacity factor seasons (winter and fall) experiencing lower up ramps than the higher capacity factor cases. The maximum down ramp rate observed was essentially the same across all cases, and in fact was a 100% turndown in the span of a second based off the previously established ~55kW maximum stack power in the benchmarking tests (Table 2).

3.2.4 VRES Load Following – Wind Turbine Farm

The wind load following test utilized 3 weeks of measured net electrical power output from the Tehachapi wind farm on a 5-minute resolution (Figure 28). Due to the order of magnitude difference between the electrolyzer system and the wind farm data, normalization was applied to match the wind farm output scale 1:1 with the electrolyzer system capacity (Figure 29).

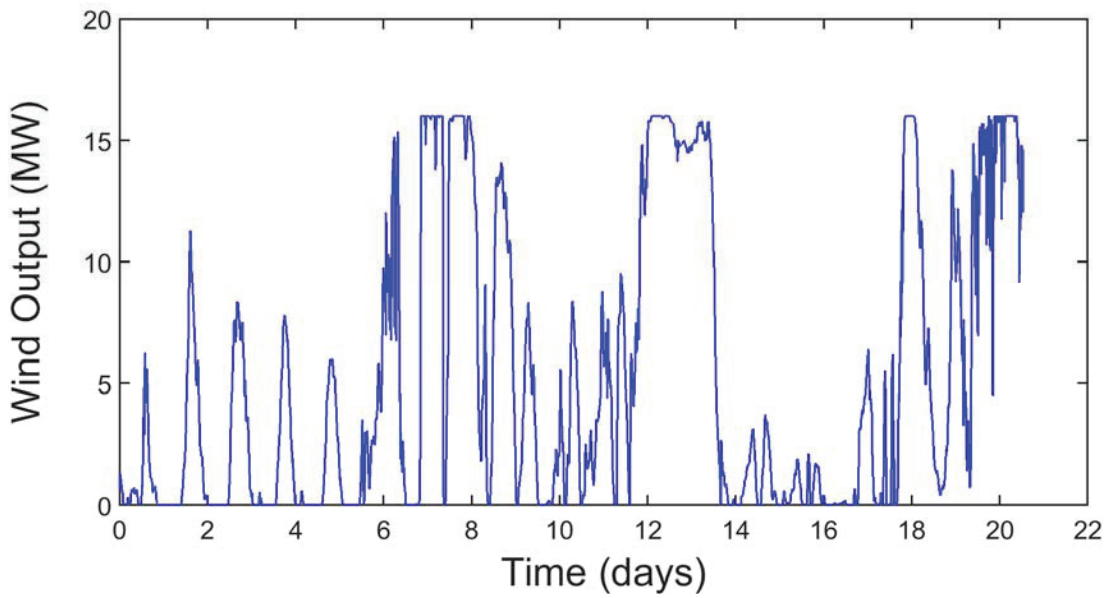


Figure 28. Tehachapi 1-month wind farm output profile utilized in wind load following test.

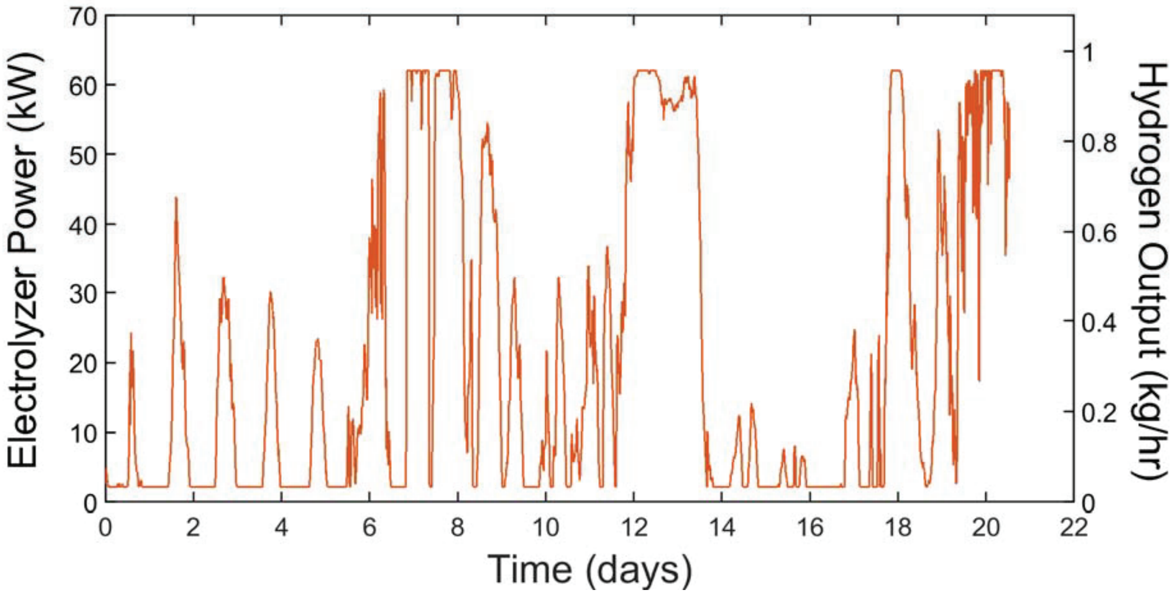


Figure 29. Normalized wind farm output for wind load following test.

Figure 30, Figure 31, and Figure 32 show the hydrogen output response for weeks one, two, and three, respectively. In contrast to the solar load following runs, the wind load following involved prolonged minimum H_2 output operation (~0.03 kg/hr H_2), representative of an idling state. As observed previously, at near full output, the hydrogen flow rate begins to fluctuate dramatically, but otherwise remained smooth.

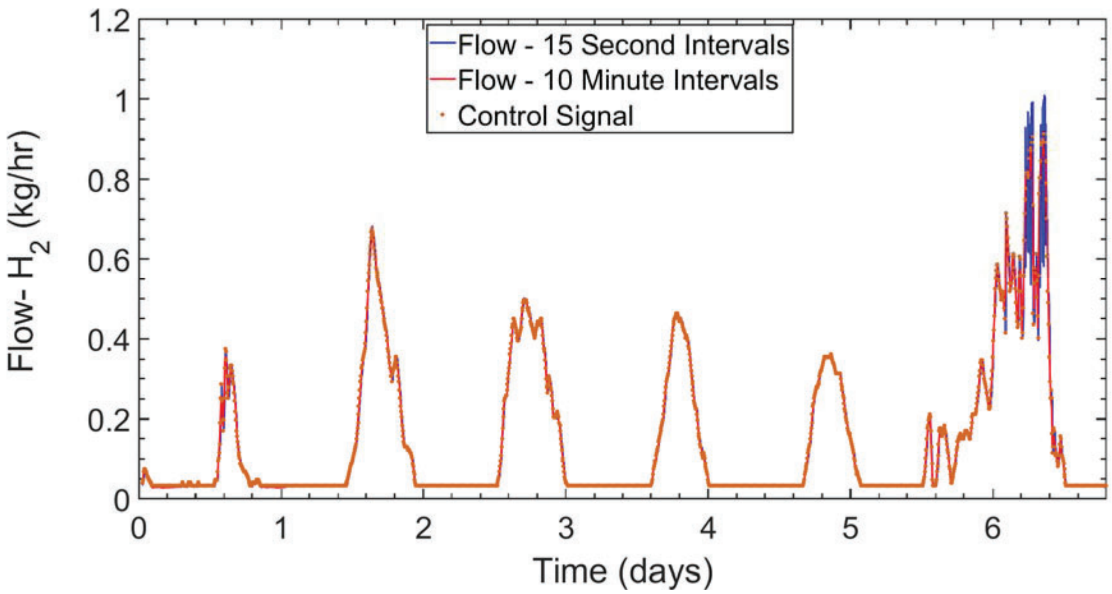


Figure 30. Wind load following test week one, hydrogen output versus control signal.

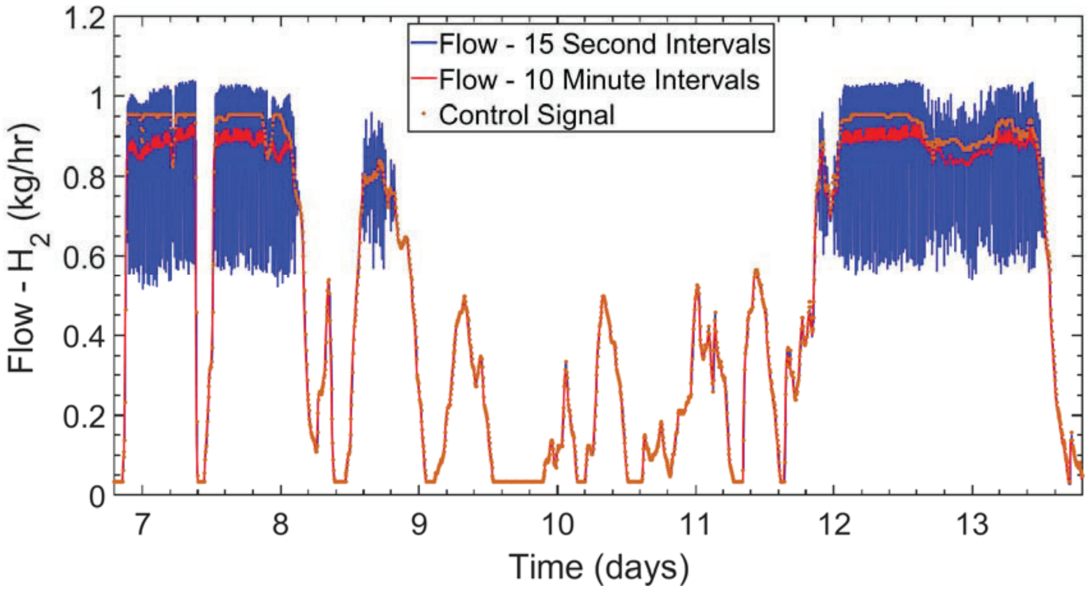


Figure 31. Wind load following test week two, hydrogen output versus control signal.

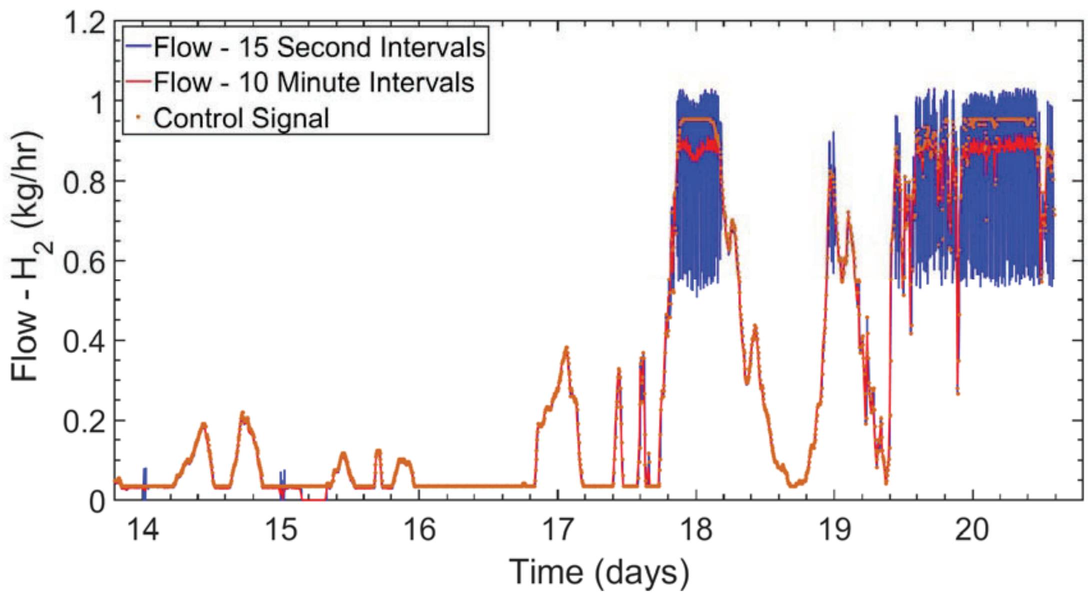


Figure 32. Wind load following test week three, hydrogen output versus control signal.

Figure 33, Figure 34, and Figure 35 display the electrolyzer system's power consumption relative to the expected control signal for weeks one, two and three respectively. The electrolyzer system had no issue following the rapid power consumption transients called for by the wind farm profile.

There are two clear trends of interest in the system power consumption. First and most significant is the clear 'minimum' power consumption set point of roughly ~ 14kW$_{el}$ when the hydrogen output is at the 0.03 kg/hr H_2 minimum set point up to approximately 0.15 kg/hr. This suggests that the electrolyzer system controls do not reduce power consumption below this point and instead hydrogen is vented beyond this point. For this reason, the flow controller minimum setpoint should not be used, but rather the 0.15 kg/hr setpoint. At 0.03 kg/hr H_2, the specific energy cost of hydrogen production is 433.3 kWh$_{el}$/kg H_2, and at 0.15 kg/hr H_2, it is 93.3 kWh$_{-el}$/kg H_2, four-fold improvement in efficiency. By extension, the 14-kW system power consumption setpoint (22.5% load condition) is the true minimum at which the electrolyzer system produces hydrogen at a reasonable efficiency.

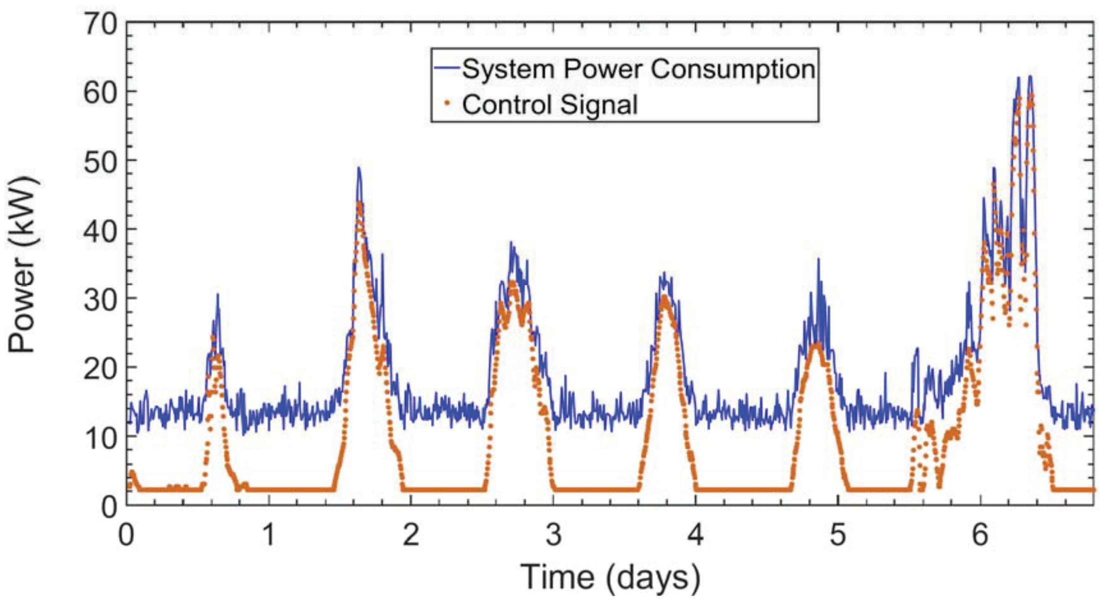


Figure 33. Wind load following test week one, system power consumption versus control signal.

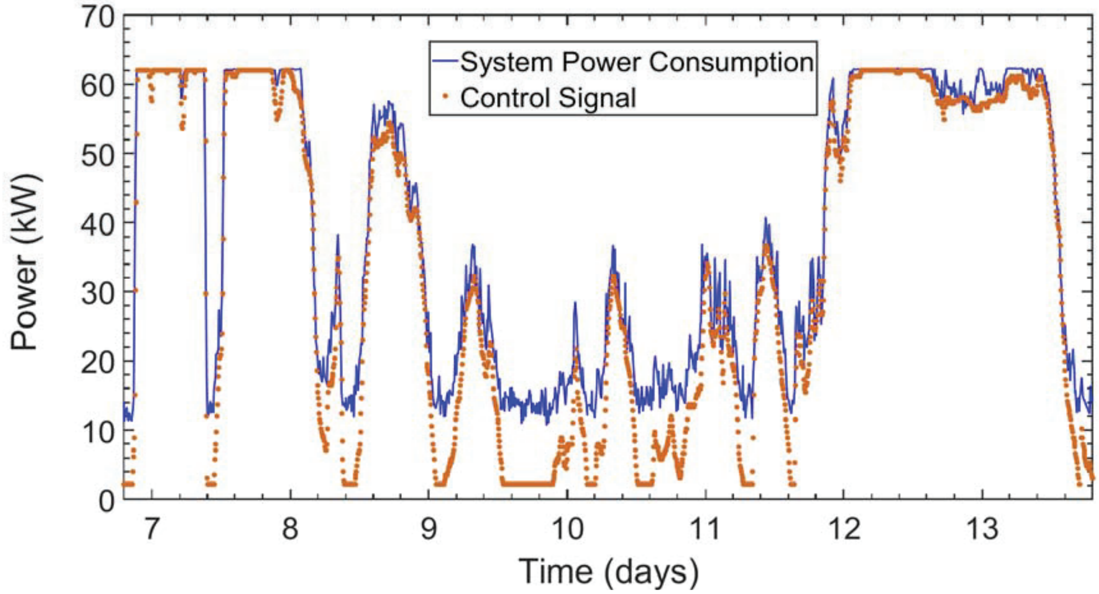


Figure 34. Wind load following test week two, system power consumption versus control signal.

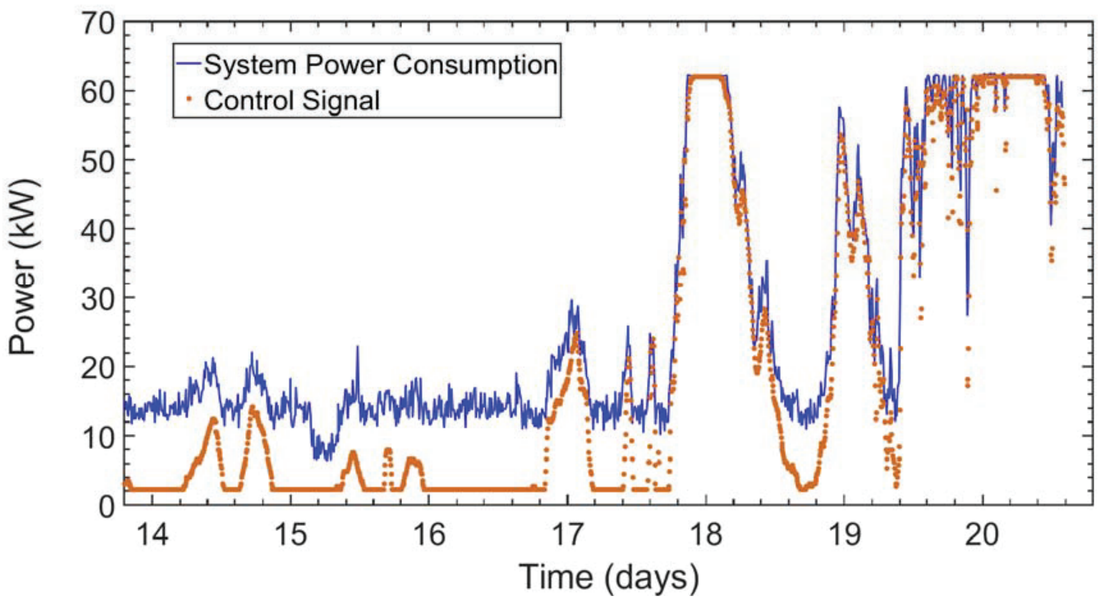


Figure 35. Wind load following test week three, system power consumption versus control signal.

The results of the three separate weeks and the overall performance are tabulated in Table 2. Splitting the runs up helps highlight the effects that the dynamic nature of wind power, even in an aggregated wind farm format averaged over a week-long period, has on the electrolyzer system, with capacity factors as low as 30% in week one up to 62% the next week. System efficiency suffers at these lower capacity factors, even as stack efficiency climbs, as previously observed in the sustained part load operation as well as the solar load following tests. More dramatic, is the observed slew rates, with the stack ramping up as much as 54.75 kW in a second. Stack maximum power varies with operating conditions, but typically is in the range of 53 to 56kW. For the conditions at that time, this was essentially a 100% up-ramp in power from zero. Similar down-ramps were observed more regularly throughout testing.

Table 4. Summary of wind load following tests.

	Week 1	Week 2	Week 3	Overall
Capacity Factor (%System Power Consumption)	30.24%	62.09%	44.15%	45.68%
Hydrogen production (Average kg/day)	3.5509	12.0486	7.0373	7.5962
System Efficiency (%HHV H2)	31.07%	51.35%	42.06%	43.96%
Stack Efficiency (%HHV H2)	80.96%	73.48%	75.73%	75.73%
Maximum Slew Rate Up/Down - Stack (kW/sec)	46.436/ -55.154	44.672/ -55.154	54.746/ -55.154	---

3.2.5 Start-Up Analysis & Modified Wind Load Following

The amount of time the system takes to start from a completely de-energized state, or 'cold' start, is an important metric for high transient load following applications. As observed in the solar and wind load following scenarios, there is a minimum power consumption beyond which it was increasingly inefficient for the electrolyzer to operate. As the system enters this regime, it could be advantageous to cycle the system off until the load signal reaches a suitable level for operation again. From a cold start, electrolyzer systems generally go through three stages of start-up; the booting of the onboard pc and controls, the venting of the hydrogen process piping to clear any air gases that came in during downtime, and the ramping of the stack current up to full capacity.

In the case of the C10 electrolyzer system, these steps are specified to take 30 seconds for initial start-up, 130 to 600 seconds for venting of the hydrogen process piping, and 180 seconds to ramp the electrolyzer stack, for a total specified start-up time of anywhere between 5 minutes and 40 seconds to upwards of 13 and a half minutes. Actual observed start-up times were far closer to the lower end of the system specs. Furthermore, the system starts producing H_2 to the process connection rather than venting once the setpoint pressure is reached, which happens before full stack current is reached. The fastest observed start-up reached full hydrogen pressure and started production in 4 and a half minutes, full stack current at 5 and a half minutes. The slowest observed reached full hydrogen pressure at 6 minutes, and full stack current after 7 minutes. Figure 36shows the full extremes observed in start-up time against the specified fastest start-up rate.

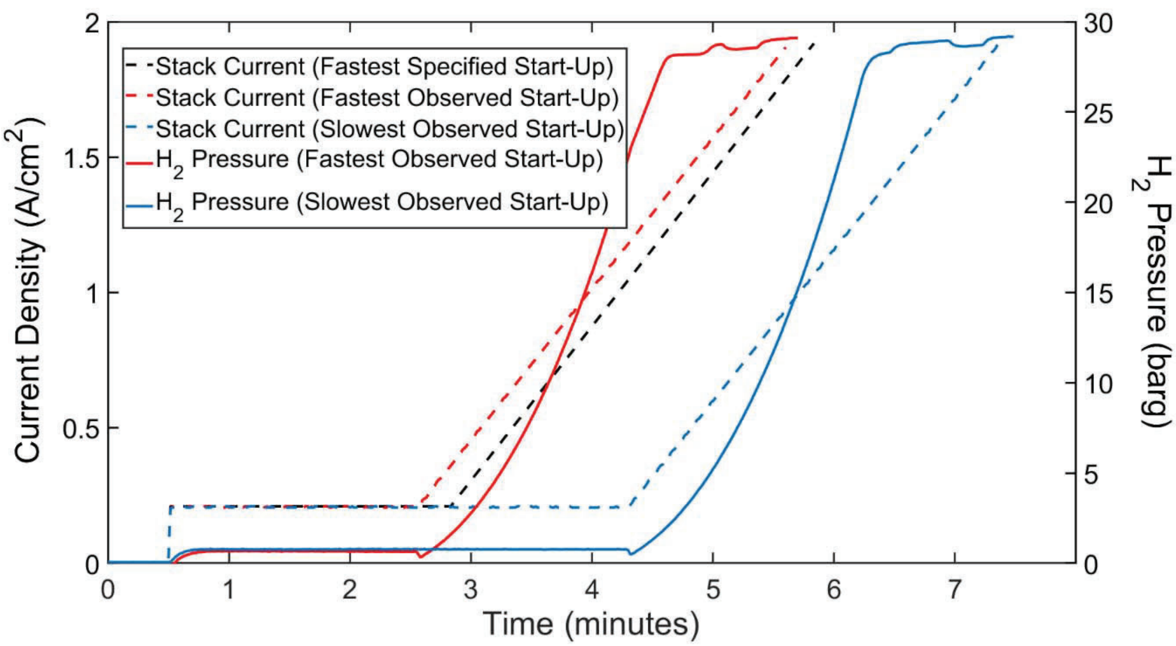


Figure 36. Fastest & Slowest observed start times of the electrolyzer system versus the OEM specs for start-up time.

The capability to cycle the electrolyzer system on/off quickly is of particular interest with respect to wind load following applications. To simulate this idea, the three-week period studied in the wind load following tests are pruned of any system activity below a 14 kW system power consumption signal. A start-up period of 5 minutes is added to each on cycle based off analysis of the system's cold start behavior, and hydrogen lost when the system cycles off is accounted for. Power consumption on shutdown was not considered as the system shutdown takes less than a minute in its entirety and only ancillary systems are using power. **Error! Reference source not found.** below summarizes the results.

The electrolyzer system cycles power on average one to two times a day, and overall spends over half the time turned off. This highlights once again the expected issue of sizing these energy storage systems for meeting the needs of balancing variable renewable energy resources. On the other hand, system efficiency does improve to a much more reasonable 55% HHV H_2.

	Week 1	Week 2	Week 3	Overall
Power Cycles (# of)	10	11	10	31
Downtime (% Hours off/Hours Total)	73.43%	30.07%	60.38%	54.62%
Capacity Factor (%System Power Consumption)	14.44%	55.72%	31.16%	33.77%
Hydrogen production (Average kg/day)	3.03	11.78	6.62	7.14
System Efficiency (%HHV H2)	55.55%	55.95%	56.19%	55.90%

3.2.6 Effects of Operating Conditions on Electrolysis

Electrolysis, and the electrolyzer system that carries out the process, can be heavily influenced by the dynamic operating conditions present. Using the nearly four thousand hours of operation data collected, in addition to controlled tests where only parameters of interest were allowed to vary, the influence of several significant operating parameters on the electrolyzer system are assessed. Due to the large number of data being compared, data is analyzed using analysis of variance (ANOVA) by way of the Design Expert statistical software package. In this case, ANOVA is applied to largely non-randomized experiments and as such the results are largely useful for suggesting hypotheses and identifying trends.

3.2.6.1 Effects of Operating Conditions on Electrolysis Stack

The cell voltage at which electrolysis is carried out for a given current density is known to vary with several parameters, including variable operating conditions. Lower cell voltages are desirable for a given current density as it results in lower power consumption for the same amount of hydrogen production. In our case, the temperature of the environment and the partial pressures of the species involved can be varied, and the effect on cell voltage observed. In the case of species pressure, the partial pressure contribution of water vapor and gas cross-over is assumed to be minimal on each side of the cell stack such that the measured anode pressure is described here as the O_2 pressure and the cathode pressure described here as the H_2 pressure. Uncontrolled variable operating conditions are considered as well, such as the resistivity of the feed water and the ambient temperature conditions. The full list of factors considered are displayed below in Table 5.

Table 5. List of factors utilized in ANOVA analysis for electrolyzer system study.

Factors	Units	Minimum	Maximum	Mean	Std. Dev
A - Current Density	Amps/cm^2	0.1869	1.9338	1.0885	0.5906
B - H2	kg/hr	0.0000	0.9318	0.4342	0.3318
C - Hours of Operation	Hours	1000	3800	2470.8918	605.8384
D - H2 Pressure	Barg	27.1724	31.9987	30.6286	1.2757
E - Inj Pressure	Barg	20.1081	32.1675	30.0672	2.4482
F - O2 Pressure	Barg	1.1085	2.0876	1.7506	0.1731
G - Stack Temperature	Celsius	41.5095	57.0630	55.1612	0.8623
H - Ambient Temperature	Celsius	22.6785	42.5343	29.5606	3.0419
J - H2 Temperature	Celsius	17.1274	26.7815	20.4037	1.4230
K - DI Water	MΩ-cm	1.1440	17.5408	11.1567	5.5405

Figure 37 below shows the input current density versus cell voltage data including the temperature correlation for the wider range of temperatures studied. It is evident that stack temperature is a strong predictor for cell voltage at a given current density.

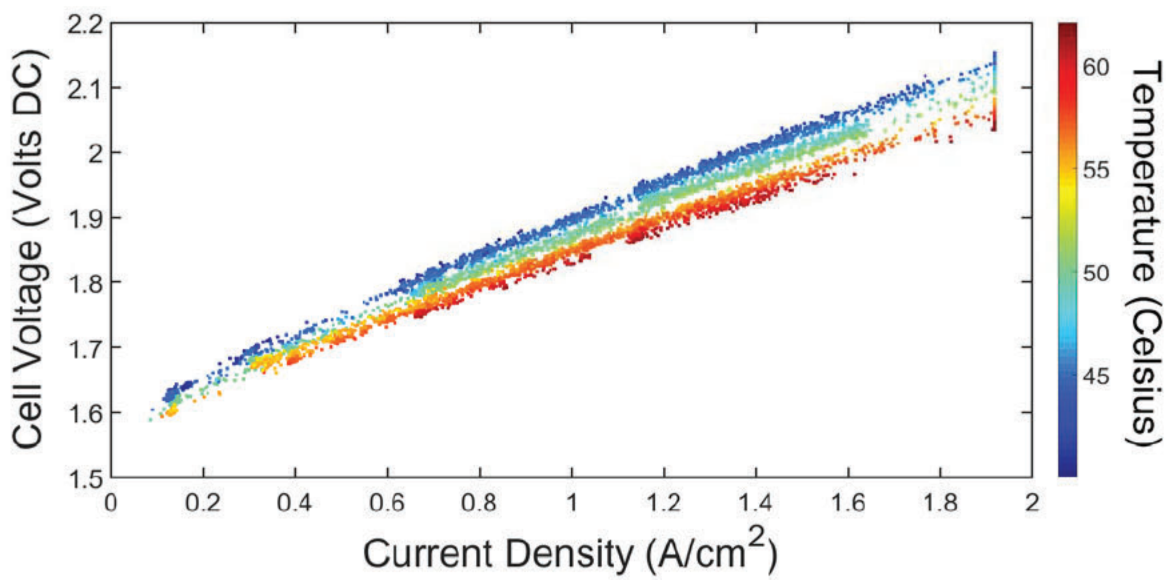


Figure 37. j-V curve across the breadth of electrolyzer testing, parsed by stack temperature.

In the case of species pressures, the effects are less obvious from a cursory observation of the j-V curve behavior. Figure 38 shows the j-V curve behavior with respect to hydrogen (cathode side) and oxygen (anode side) pressures. In the case of H_2 pressure, there is a healthy distribution of data to use albeit in the limited range of roughly 28 to 32 barg. There is no pressure regulation on the oxygen-side, and as a consequence oxygen pressure is less evenly distributed.

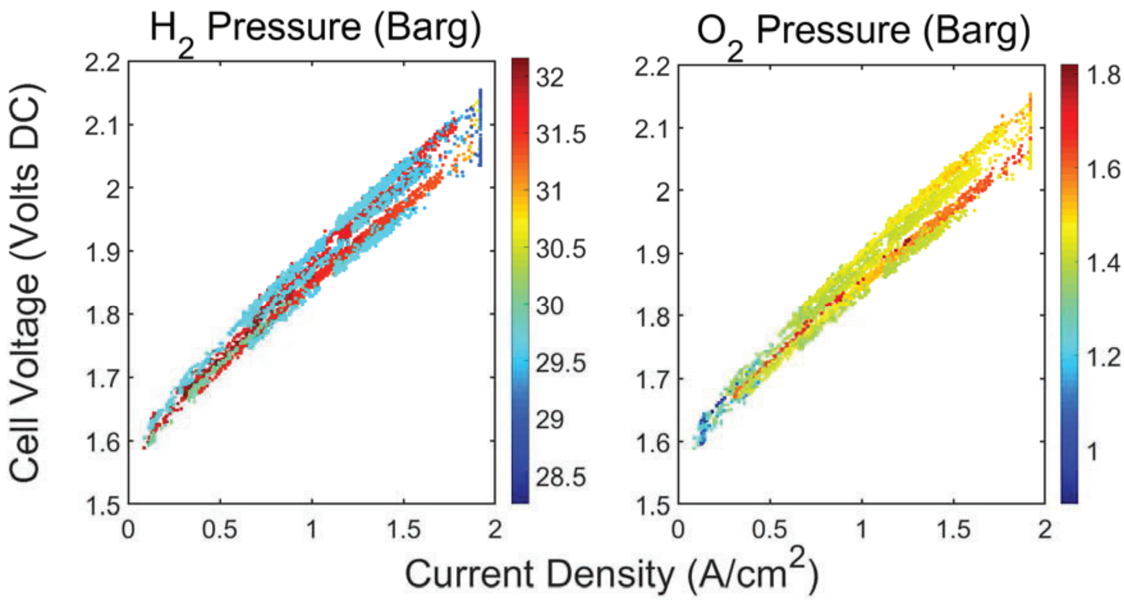


Figure 38. j-V curve across the breadth of electrolyzer testing, parsed by H_2 pressure (left) and O_2 pressure (right).

The most significant predictors of cell voltage in order of significance were current density, stack temperature, and hydrogen pressure. Overall the model is a strong predictor of j-V behavior with an R^2 value greater than 0.99. A linear model was used as the j-V region considered was in the largely 'linear' region of the relation, although nonlinearities would begin to appear at lower current densities that were not included. The results of the ANOVA analysis on cell voltage is displayed below in Table 6.

Table 6. Results of ANOVA analysis on cell voltage.

	Sum of Squares	Degrees of Freedom	Mean Square	F Value	P-value (Prob > F)
A-Current Density	82.5536	1	82.5536	75271.2063	< 0.0001
D-H_2 Pressure	0.0099	1	0.0099	9.0030	0.0028
G-Stack Temperature	0.0849	1	0.0849	77.4291	< 0.0001
Model	110.1166	3	36.7055	33467.5768	< 0.0001

Std. Dev.	0.0331	**R^2**	0.9936
Mean	3.2808	**Adjusted R^2**	0.9935

The trend predictions match up with what was observed for current density and stack temperature in the j-V curve; higher temperatures result in lower cell voltages.

Increasing pressures on the hydrogen side increase cell voltage slightly, which is the expected trend. According to the ANOVA model, going from 28 barg to 32 barg hydrogen incurs an overvoltage of 4.64 ± 3.48 mV per cell. The overvoltage incurred by pressurization of the hydrogen side is not well understood but is typically attributed to the predicted change in Nernst (reversible) voltage as described in equation (2) below.

$$E_{OCV}(T,P) = 1.228 - 0.0009(T_{avg} - 298.15) + \frac{RT}{2F}\left[\ln\left(\frac{P_{H2,cathode}P_{O2,anode}^{0.5}}{a_{H2O,anode}}\right)\right] \qquad (2)$$

Our ANOVA model prediction for hydrogen pressurization is in line with the predicted change in voltage by the Nernst equation of 2 mV going from 28 to 32 barg. The losses due to pressurization of hydrogen in this fashion are of great interest due to the potentially much higher compression efficiency relative to traditional mechanical based methods. Electrochemical compression is explored further in section.

While the effect of varying O_2 pressure was not found to be significant across cell voltage measurements according to the ANOVA analysis, the general predicted trend was still of interest. Increasing oxygen pressure was generally correlated with higher cell voltages, which also agrees with the expected result. However, the overvoltage prediction is higher than would be expected, with a 1 barg increase in pressure from 1 barg O_2 to 2 barg O_2 predicted to incur a 16.33 ± 5.72 mV overvoltage. According to the Nernst equation this should only incur a ~4.79 mV overvoltage. Given the poor distribution of oxygen pressure data across all other operating conditions, this incongruence is unsurprising.

3.2.6.2 Effects of Operating Condition on Electrolyzer System Efficiency

From a system level perspective, the same operating conditions considered in Table 5 are of interest. The ANOVA results for the entire range of system efficiency considered are summarized below in Table 8. The ANOVA model prediction is fairly strong with an R^2 value of 0.85. Both current density and H_2 pressure showed significant influence on system efficiency. O_2 pressure as well seemed to have an influence, although due to the uncontrollable nature of the oxygen pressure, the effects are not nearly as clear. These three terms comprise the ANOVA model. Temperature did not show any significant influence on system efficiency (Figure 39).

Table 7. Results of ANOVA analysis on system efficiency, all data points & stack temperature excluded.

	Sum of Squares	Degrees of Freedom	Mean Square	F Value	P-value (Prob > F)
A-Current Density	1.398E+11	1	1.398E+11	1677.1253	<0.0001
D-H_2 Pressure	2.634E+09	1	2.634E+09	31.6038	<0.0001
F-O_2 Pressure	2.506E+08	1	2.506E+08	3.0066	0.0834
Model	3.149E+11	3	1.050E+11	1259.3299	<0.0001

Std. Dev.	9129.4467	**R^2**	0.8528
Mean	26969.3660	**Adjusted R^2**	0.8521

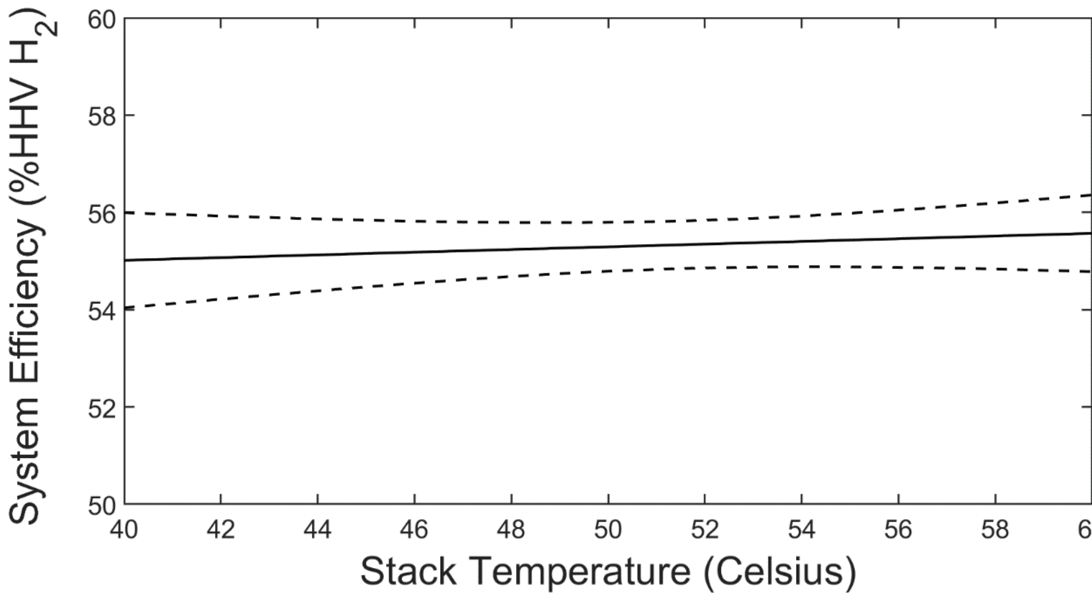


Figure 39. ANOVA prediction of stack temperature influence on system efficiency, dashed lines depict 95% confidence intervals (j = 1 A/cm^2, P_{H2} = 30 barg, P_{O2} = 1.5 barg).

There is a stronger influence on overall system efficiency from H_2 pressure and, to a lesser extent, O_2 pressure. Figure 40 and Figure 41 show these distributions below.

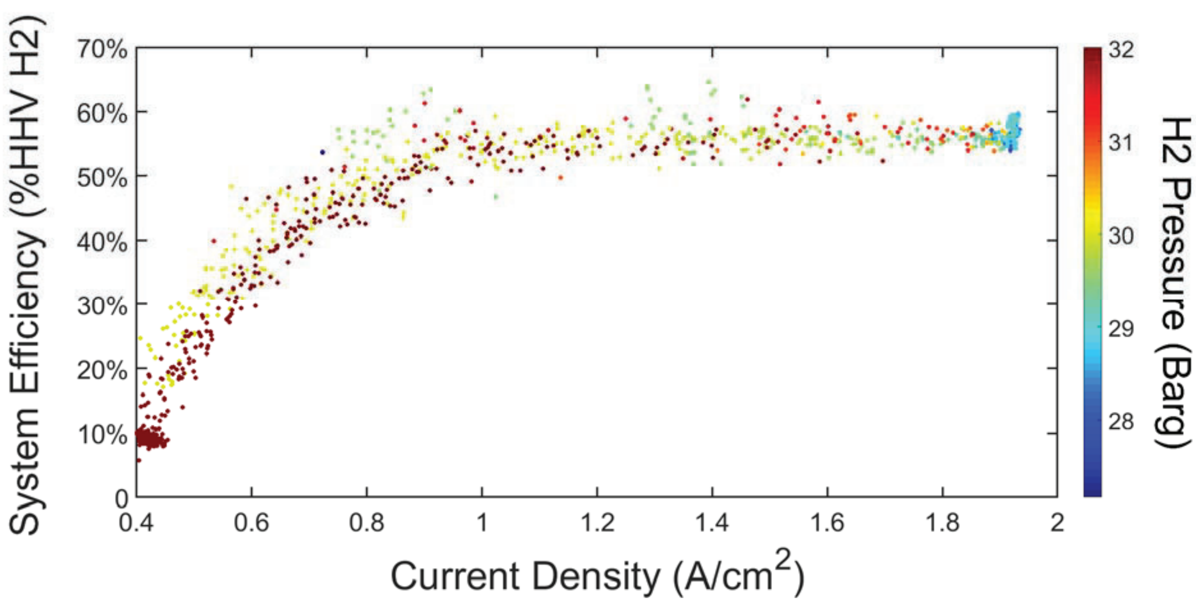


Figure 40. System efficiency versus current density with H_2 pressure distribution.

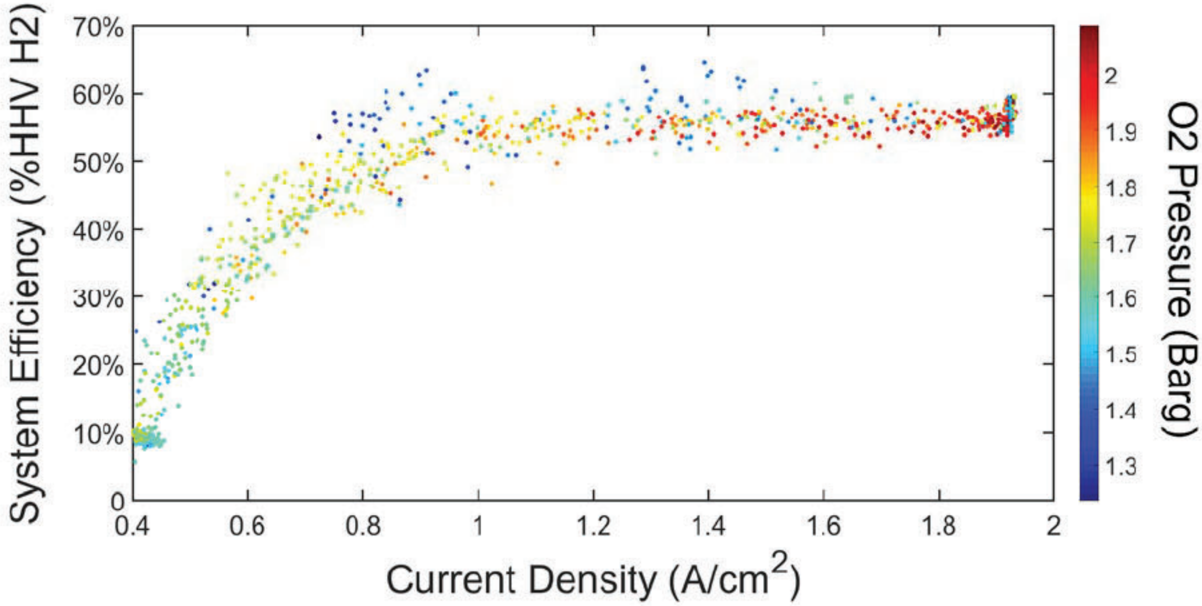


Figure 41. System efficiency versus current density with O_2 pressure distribution.

The ANOVA results for the entire range of system efficiency considered are summarized below in Table 8. The full range of system efficiency responses resulted in a much better fit for the ANOVA model prediction with an R^2 value of 0.85. Both current density and H_2 pressure showed significant influence on system efficiency. O_2 pressure as well seemed to have an influence, although due to the uncontrollable nature of the oxygen pressure, the effects are not nearly as clear. These three terms comprise the ANOVA model.

Table 8. Results of ANOVA analysis on system efficiency, all data points & stack temperature excluded.

	Sum of Squares	Degrees of Freedom	Mean Square	F Value	P-value (Prob > F)
A-Current Density	1.398E+11	1	1.398E+11	1677.1253	<0.0001
D-H_2 Pressure	2.634E+09	1	2.634E+09	31.6038	<0.0001
F-O_2 Pressure	2.506E+08	1	2.506E+08	3.0066	0.0834
Model	3.149E+11	3	1.050E+11	1259.3299	<0.0001

Std. Dev.	9129.4467	**R^2**	0.8528
Mean	26969.3660	**Adjusted R^2**	0.8521

The predicted effects of varying H_2 and O_2 pressure on system efficiency are shown below in Figure 42 and Figure 43 respectively. Hydrogen pressure has a clear negative correlation with system efficiency that grows at lower current density regimes.

Interestingly, O_2 pressure has a positive correlation with system efficiency. The overlapping confidence intervals suggest that this trend could be in large part arbitrary. There is already a strong correlation of high oxygen pressure with high current density as well, which obscures effective analysis of the effects of oxygen pressure.

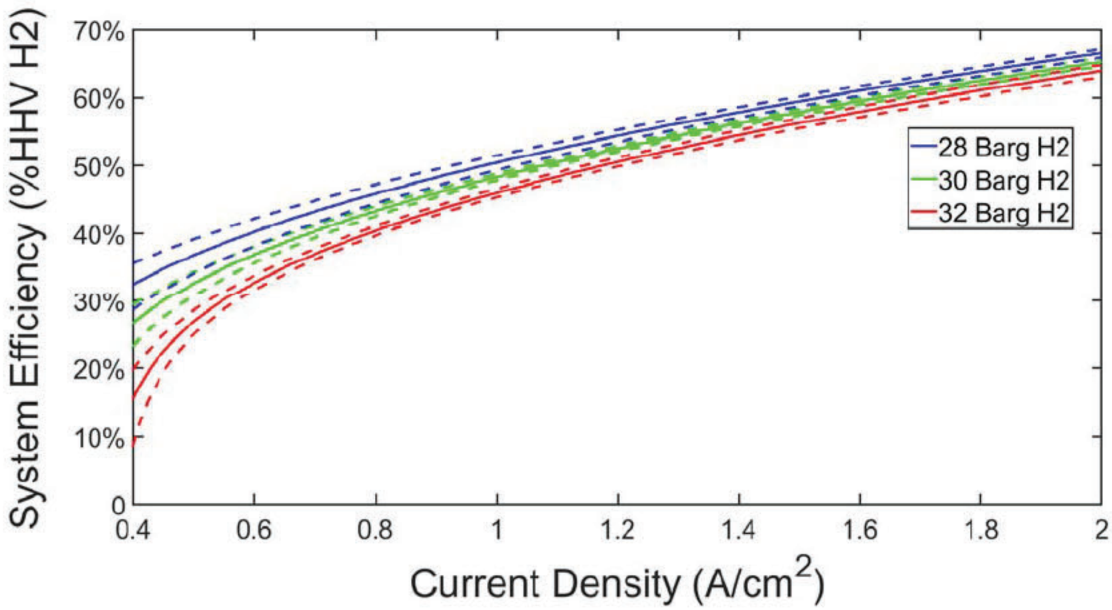


Figure 42. ANOVA prediction of H_2 pressure influence on system efficiency, dashed lines depict 95% confidence intervals (P_{O2} = 1.5 barg).

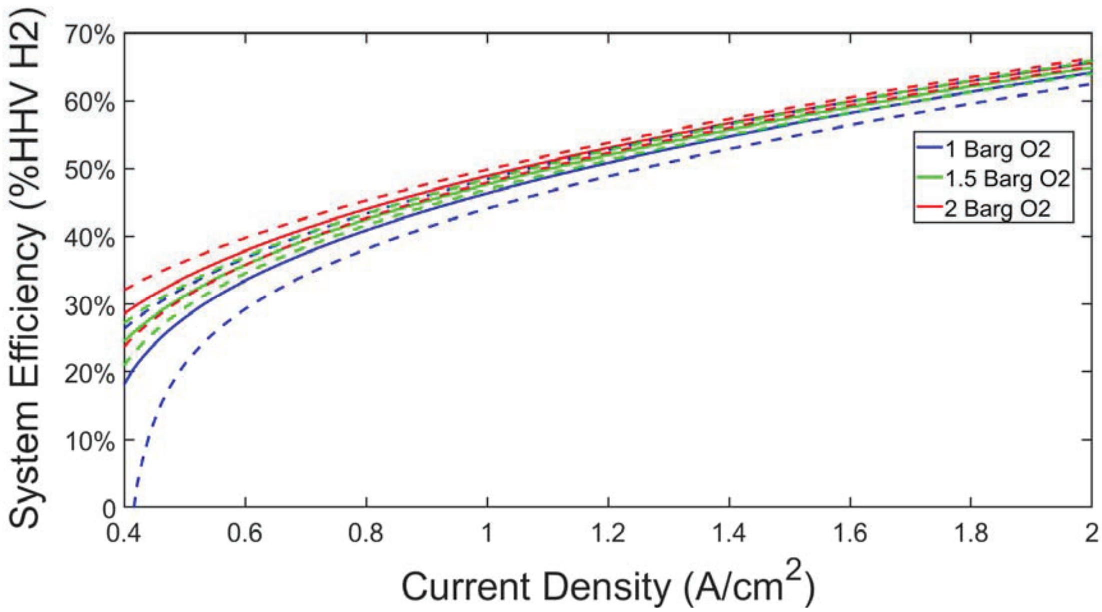


Figure 43. ANOVA prediction of O_2 pressure influence on system efficiency, dashed lines depict 95% confidence intervals (P_{H2} = 30 barg).

3.2.6.3 Effects of Operating Conditions on H_2 losses

Several factors outside of the efficiency of the electrolysis process can influence the overall system efficiency. Previously established during the sustained part load operation testing was the contribution of hydrogen gas losses to lower system efficiencies as load condition decreases. It is reasonable then to look for matching trends with respect to system efficiency for the measured hydrogen losses. Figure 44 and Figure 45 show the distribution of hydrogen and oxygen pressure respectively for % of hydrogen loss versus current density.

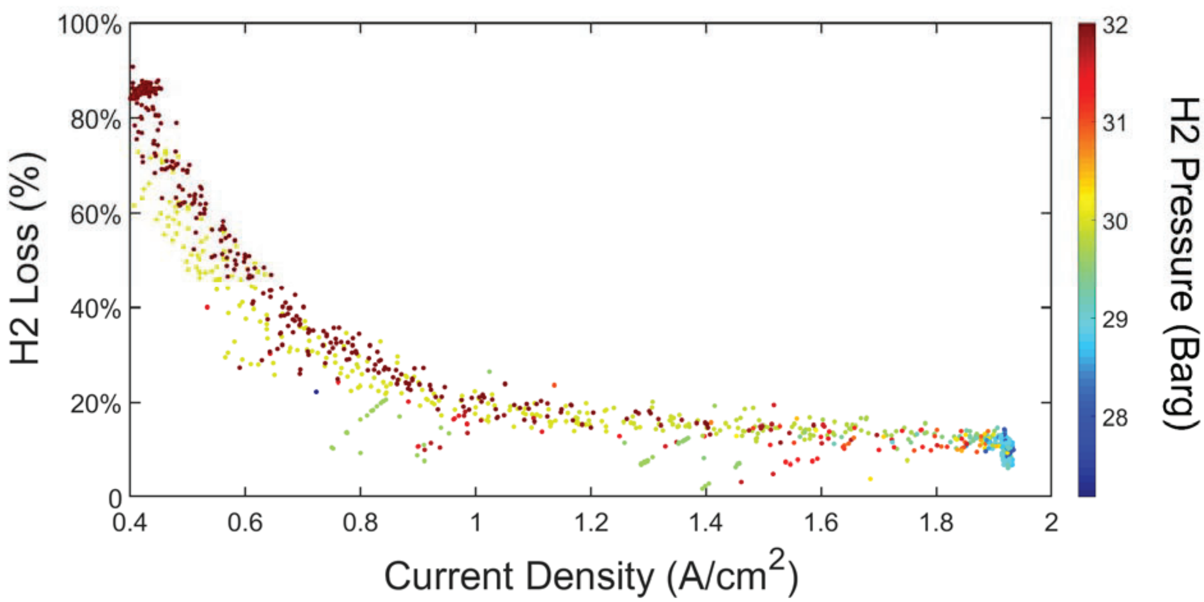


Figure 44. %H_2 loss versus current density with H_2 pressure distribution.

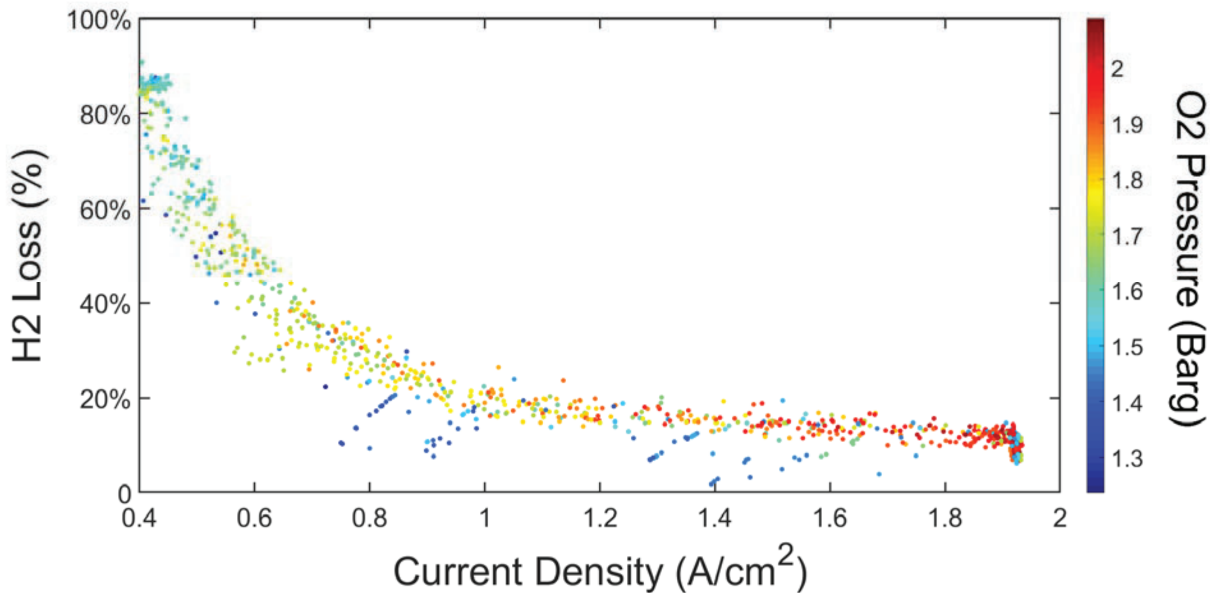


Figure 45. %H_2 loss versus current density with O_2 pressure distribution.

The ANOVA results for %H_2 loss are summarized below in Table 9, and closely mirror the results of the system efficiency analysis. The model fit is slightly stronger, and the H_2 pressure significance was found to be higher while the O_2 pressure significance decreased. Figure 46 and Figure 47 show the model correlation for H_2 and O_2 pressure respectively. The confidence intervals for the H_2 pressure variation tightened considerably, and in combination with the clear distribution of higher H_2 losses at higher H_2 pressures observed in Figure 44, it is certain that higher H_2 pressures lead to greater H_2 losses. O_2 pressure does not clearly impact the hydrogen losses.

Table 9. Results of ANOVA analysis on %H_2 loss.

	Sum of Squares	Degrees of Freedom	Mean Square	F Value	P-value (Prob > F)
A-Current Density	1.1498	1	1.1498	4118.7081	< 0.0001
D-H2 Pressure	0.0111	1	0.0111	39.6783	< 0.0001
F-O2 Pressure	0.0000	1	0.0000	0.0150	0.902555
Model	2.4138	3	0.8046	2882.0607	< 0.0001

Std. Dev.	0.0167	R^2	0.9299
Mean	0.1765	Adjusted R^2	0.9296
C.V. %	9.4669	Predicted R^2	0.9287
		Adeq Precision	172.4244

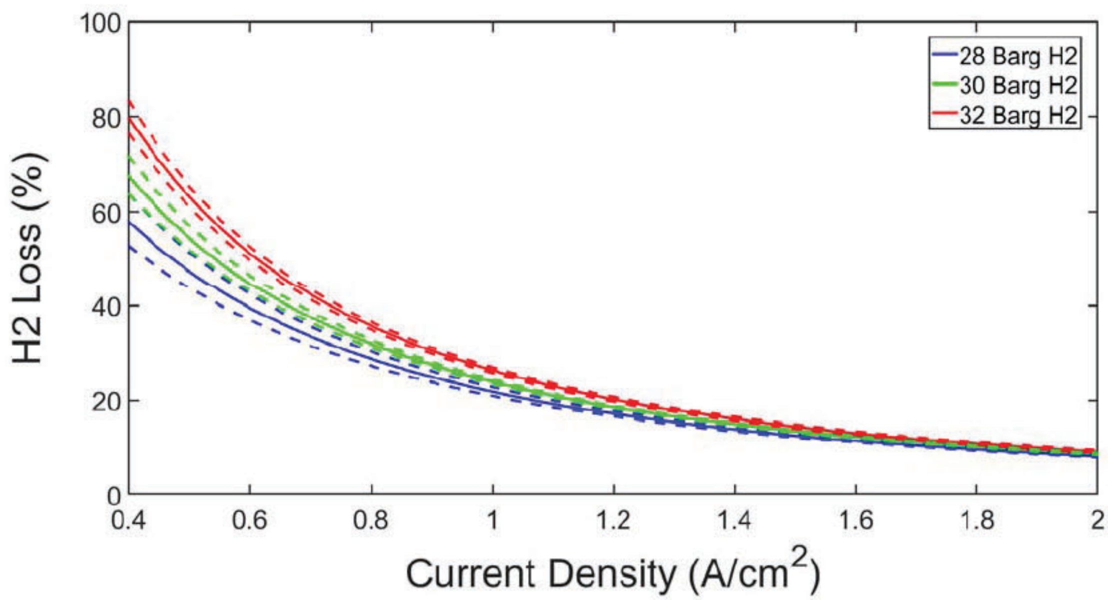


Figure 46. ANOVA prediction of H_2 pressure influence on H_2 efficiency, dashed lines depict 95% confidence intervals (P_{O2} = 1.5 barg).

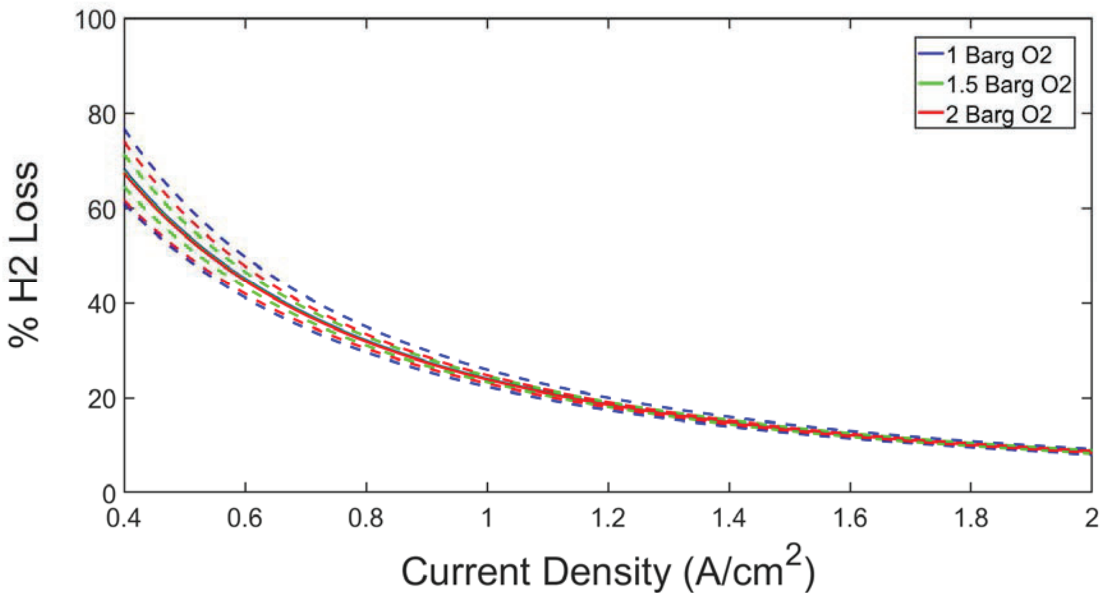


Figure 47. ANOVA prediction of O_2 pressure influence on system efficiency, dashed lines depict 95% confidence intervals (P_{H2} = 30 barg).

3.2.6.4 Effects of Operating Conditions on AC/DC Power Electronics

The AC/DC power electronics are another significant source of loss in system efficiency that could be influenced by operating conditions. Figure 14 demonstrated a clear correlation between lower ambient temperatures and higher AC/DC power electronics efficiency, although only at 100% load conditions (~1.92 A/cm^2). In sustained part load testing, no such correlation was found, although the range of ambient temperatures operated were limited. Figure 48 shows the observed AC/DC power electronics efficiency versus current density and the distribution of ambient temperatures.

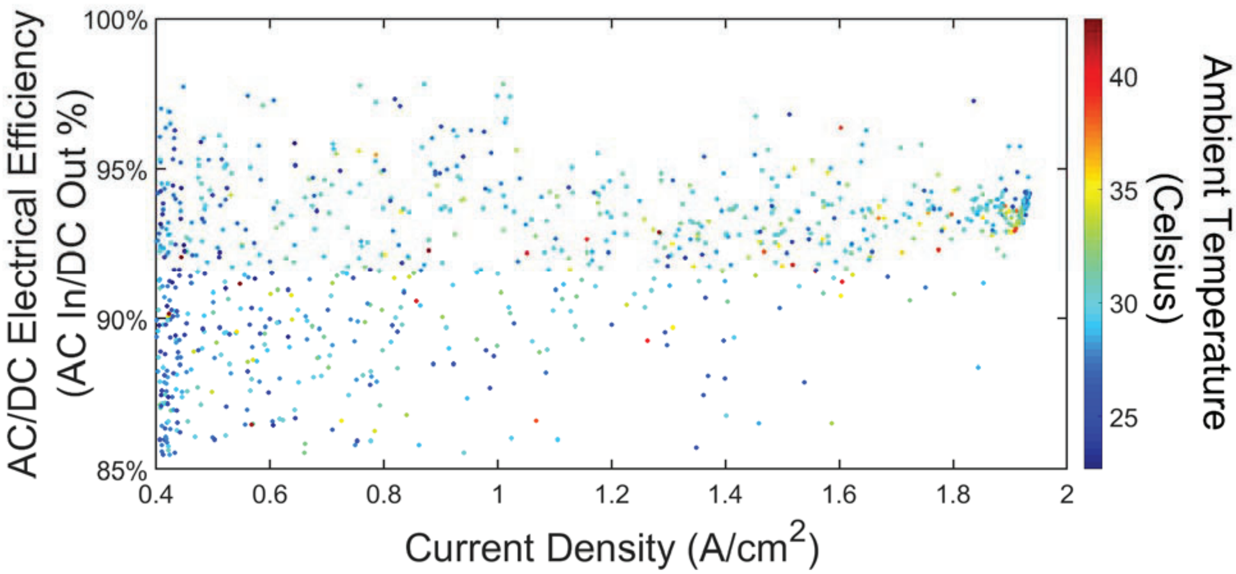


Figure 48. AC/DC power electronics efficiency versus current density with ambient temperature distribution.

There is an overall poor correlation between lower current densities, ambient temperature, and resulting AC/DC power electronics efficiency (Table 10). Figure 49 shows the ANOVA model prediction, showing a general down trend in AC/DC efficiency with decreasing current density. Lower ambient temperatures are also correlated with higher AC/DC power electronics efficiencies. While the model itself is not a powerful predictor of AC/DC efficiency, the trends in efficiency do appear to be accurate. A cursory glance at the data distribution (Figure 48) suggests that ambient temperature is weighted to be lower at lower current densities and that this may influence the ANOVA analysis. A closer examination of the data shows that the average ambient temperature for the high current density regime, low current density regime, and entirety of the points is around 28 degrees Celsius.

Table 10. Results of ANOVA analysis on AC/DC power electronics efficiency.

	Sum of Squares	Degrees of Freedom	Mean Square	F Value	P-value (Prob > F)
A-Current Density	1177.9947	1	1177.9947	123.8344	< 0.0001
H-Ambient Temperature	28.5512	1	28.5512	3.0014	0.0837
Model	1246.3817	2	623.1909	65.5117	< 0.0001

Std. Dev.	3.0843	**R^2**	0.1671
Mean	91.0731	**Adjusted R^2**	0.1646

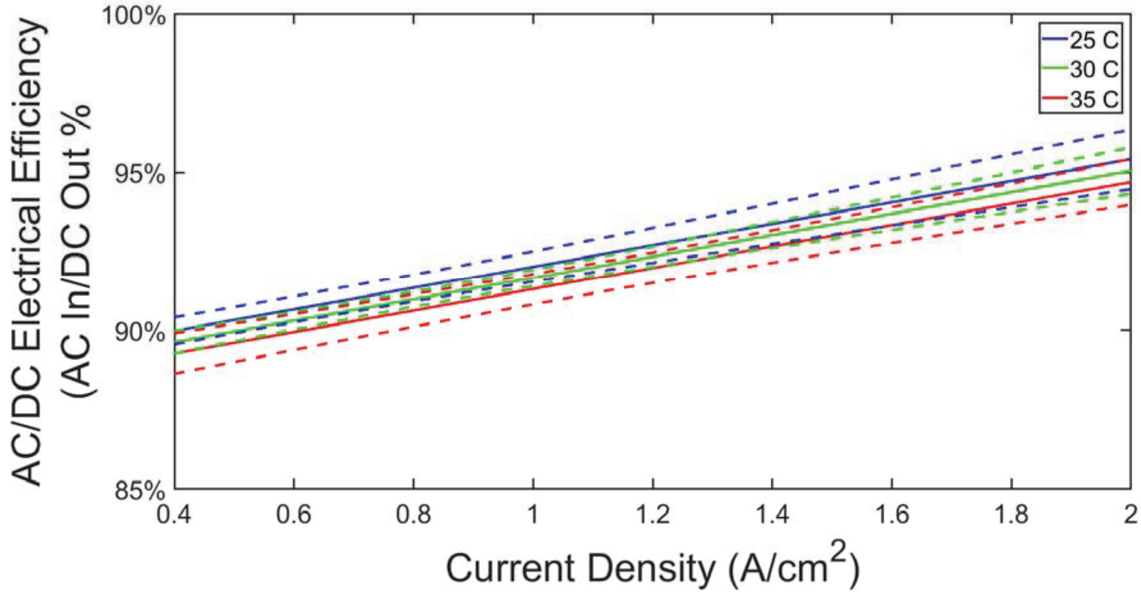


Figure 49. ANOVA prediction of ambient temperature on H_2 efficiency, dashed lines depict 95% confidence intervals.

3.2.6.5 Synthesis of System Efficiency and Specific Energy Analysis

Figure 50 shows the specific energy consumption of electrolysis (kWh of electrical energy per kg of hydrogen produced) at the system level. It becomes particularly clear that operating the electrolyzer near the 0.4 A/cm^2 and lower entails massive losses with specific energy costs in the regime of 400 kWh/kg H_2 and higher (a 6-7x fold increase in energy cost from the rated specific energy consumption of 65 kWh/kg H_2 at full load).

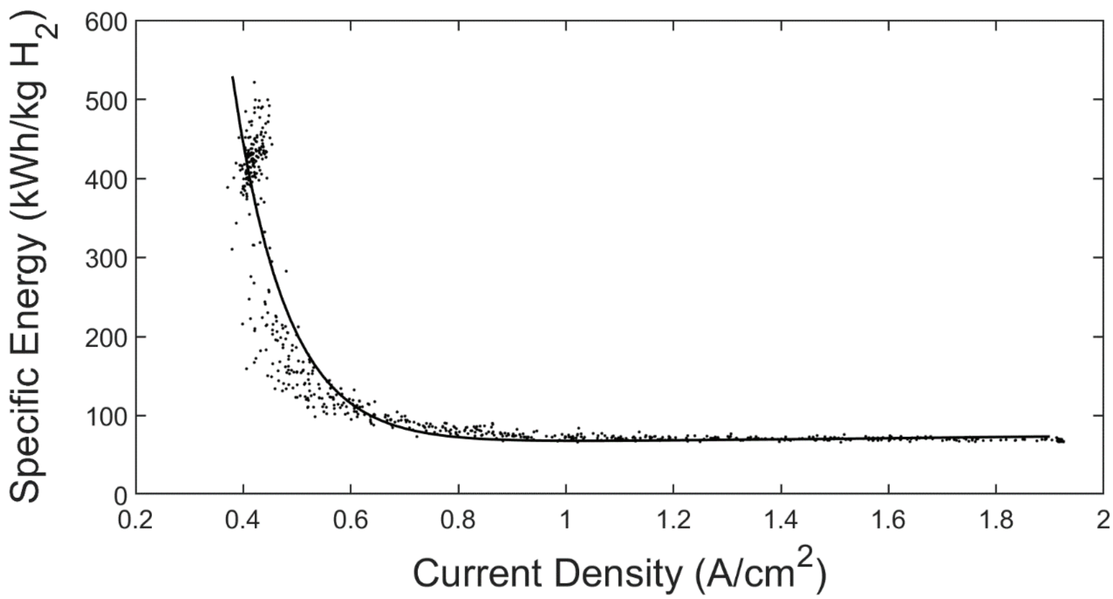


Figure 50. Specific energy cost of electrolyzer system versus current density.

The specific energy consumption of the system can be broken down into four sources of energy consumption – the electrolysis process or 'stack' energy consumption, the energy consumption of H_2 loss, energy consumption associated with the AC/DC power electronics, and the energy consumption of the balance of plant. Figure 51 shows this breakdown relative to Figure 50. As current density decreases, the efficiency of the electrolysis process increases thus the downtrend in specific energy consumption for the stack. AC/DC power electronics and ancillary power consumption losses are roughly on the same order of magnitude and are similar in trend although ancillary power consumption increases steadily while the power electronics consumption remain largely flat. This trend continues until the minimum load condition is hit at roughly 0.4 A/cm^2 beyond which reductions in hydrogen output just dramatically increase specific energy consumption. Figure 52 shows the percentage share of the total system specific energy consumption.

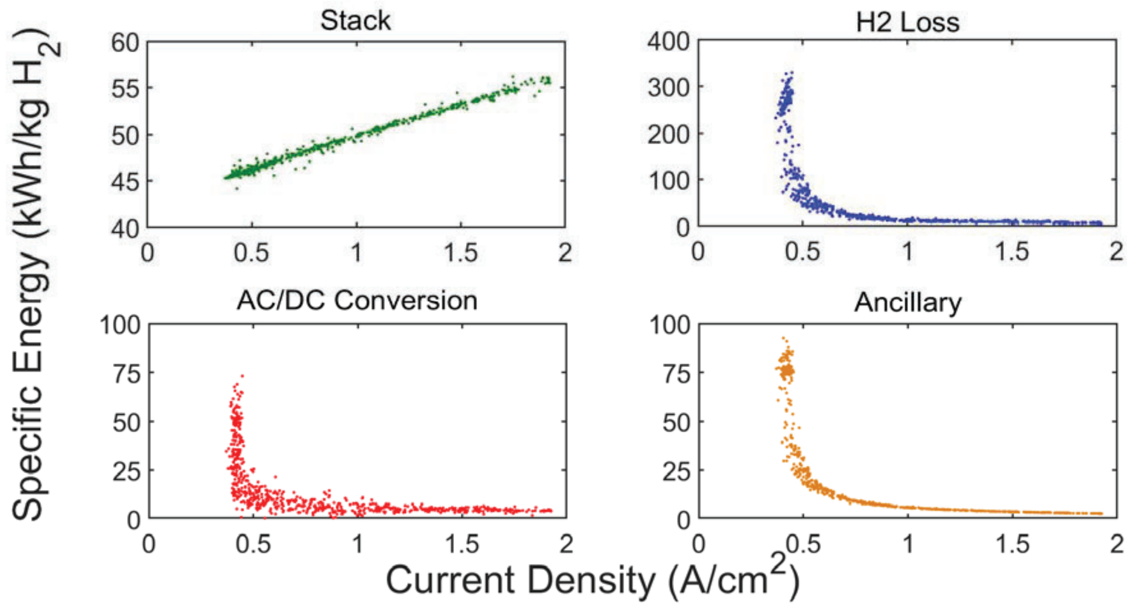


Figure 51. Specific energy consumption of electrolyzer system broken down by sources of energy consumption versus current density.

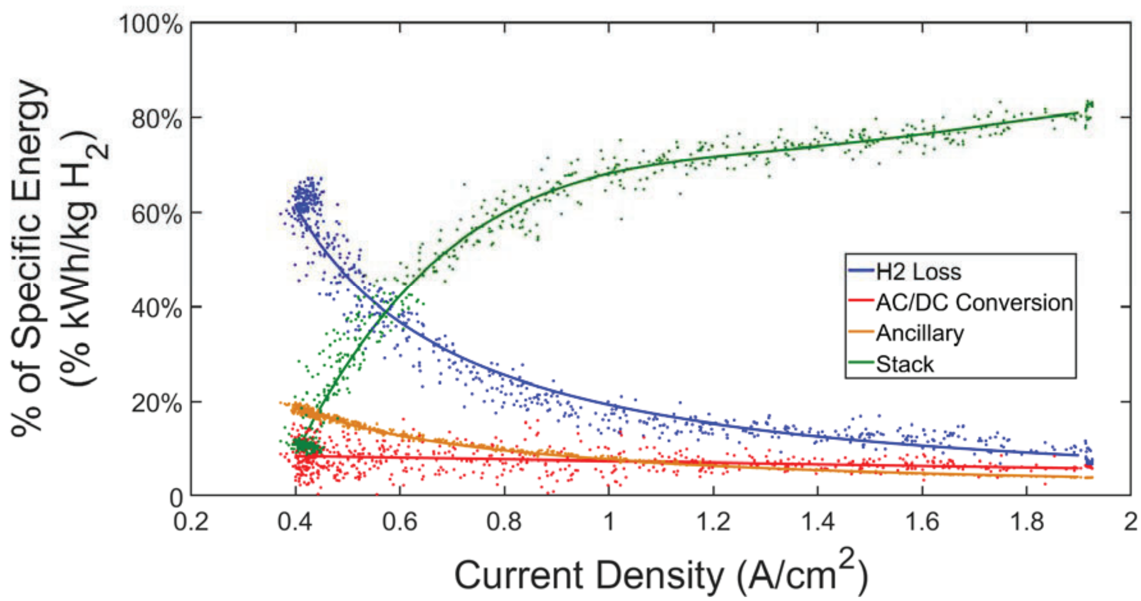


Figure 52. Percentage share of total specific energy consumption of hydrogen production by the electrolyzer system.

3.2.6.6 Degradation

Hours of operation were included in the ANOVA analysis for all analyzed responses to check for the possibility of degradation effects. Typically, PEM electrolyzer systems are expected to operate with lifetimes of 20,000 + hours, however power cycling of the cell leads to enhanced degradation [78]. Observable degradation is not an expected result nor were degradation mechanisms an aim of this study. Figure 53 shows system efficiency at full load and average mode parameter values versus total hours of operation. A general downtrend suggests that there may be observable degradation, however the large confidence intervals suggest that the downtrend is statistically insignificant.

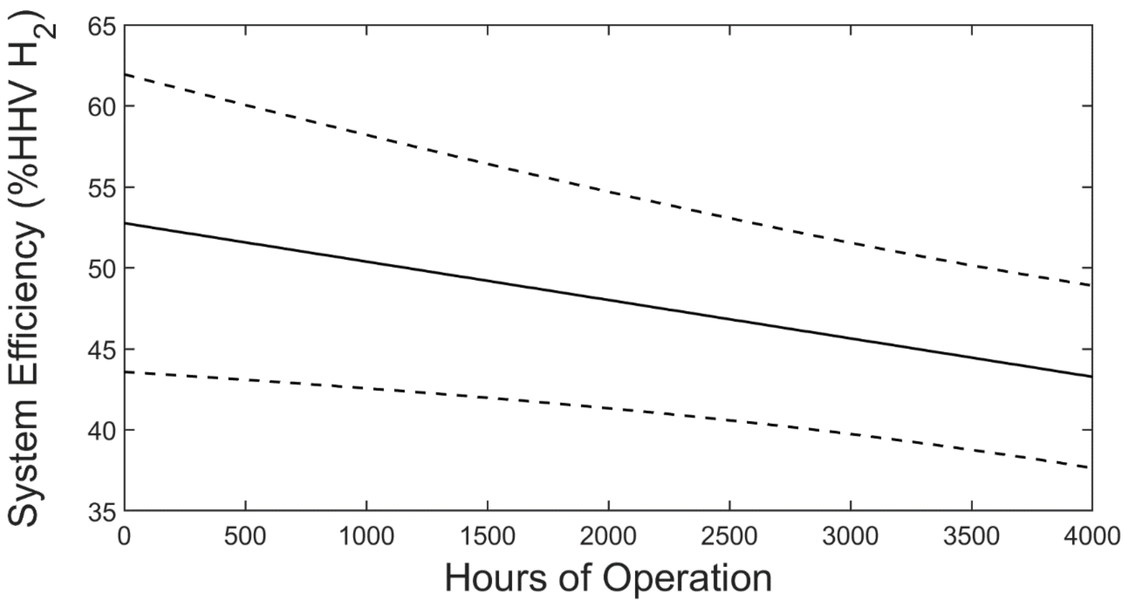


Figure 53. System efficiency versus hours of operation, 95% confidence intervals shown in dashed lines (j = 1.92 A/cm^2, P_{H2} = 30 barg, P_{O2} = 1.5 barg.

Figure 54 breaks down the mechanisms that contribute to system efficiency and show their trends versus total hours of operation. Out of these, an increase in cell voltage is the only trend that shows some significance. Tests that involved higher pressures and lower stack temperatures also occurred later in the operational period, which would lead to generally higher cell voltages. Ultimately, there is no clear degradation of the electrolyzer system after 4000 hours of operation.

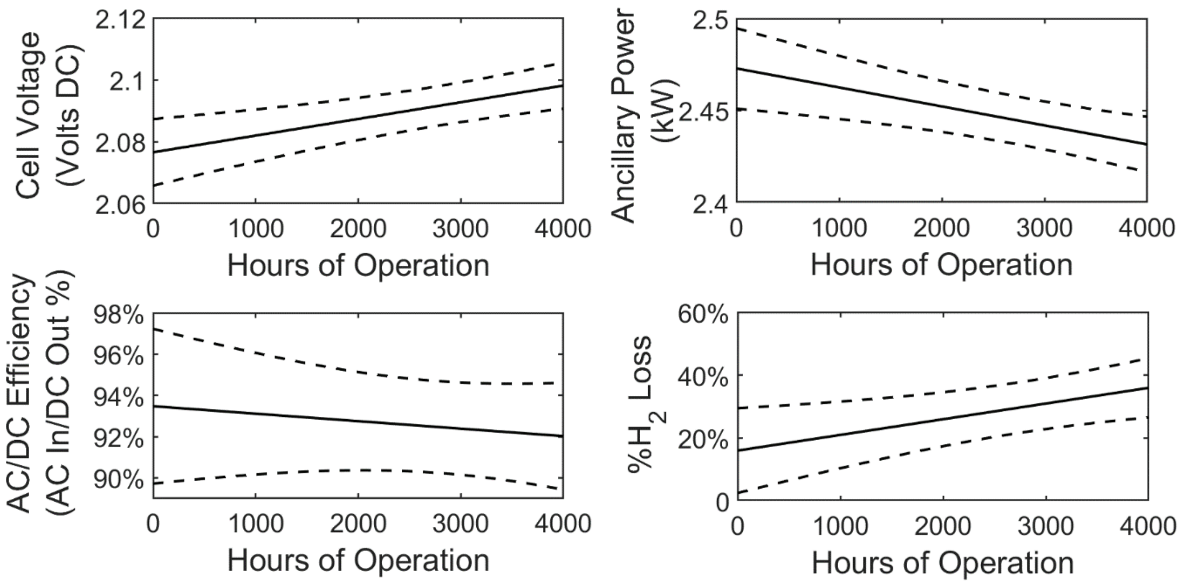


Figure 54. Cell voltage (Top Right), Ancillary Power Consumption (Top Left), AC/DC Efficiency (Bottom Left), %H_2 Loss (Bottom Right) versus hours of operation (j = 1.92 A/cm^2, P_{H2} = 30 barg, P_{O2} = 1.5 barg, T_{Stack} = 55 Celsius, $T_{Ambient}$ = 28 Celsius).

3.3 Summary & Recommendations

Over 4000 hours of operation of a commercially available 60kW PEM electrolyzer system integrated with the UC Irvine Central Plant's natural gas system and combustion turbine were achieved. Of the 4000 hours of operation, 1000 hours of steady state benchmarking, several hundred hours of sustained part load operation, and over 2000 hours of VRES load following were accomplished. The control of the PEM electrolyzer system for dynamic dispatch response to VRES load following was accomplished using a mass flow controller on the hydrogen process connection from the PEM electrolyzer system, without any physical modifications to the system itself. VRES load following was demonstrated for both a solar PV system across a wide range of conditions, and for aggregated wind turbine resources. The data acquired from the dynamic operation of the electrolyzer system indicates that PEM electrolyzers can operate under extreme power transients on a second-to-second time scale, not only at a stack level but from an overall system level, using a relatively simple and unobtrusive control strategy.

3.3.1 Observations

- A slight 'break-in' effect of the PEM stack was observed with an increasing maximum stack current observed during the first 1000 hours of operation. This was determined to not be due to the power electronics as the stack DC power supply was replaced at 600 hours with no change in the break-in trend.

- The stack AC/DC power electronics exhibited consistently higher efficiencies at lower ambient temperatures, matching expected temperature derating for DC power supplies, although at this scale the phenomenon is not well documented. This variation in AC/DC power electronics efficiency explained the diurnal trend in system efficiency observed, where the system performed better at night due to lower ambient temperatures.
- OEM rated system efficiency was 57.1% HHV H_2 (69 kWh/ kg H_2). Sustained system efficiency measured at full load conditions was around 58.5% HHV H_2 (67.42 kWh/ kg H_2) on average, increasing from 57.47% up to around 60% HHV H_2 across the sustained full load runs during the first 1000 hours.
- The power consumption of the chiller unit providing cold water to the electrolyzer system heat exchangers was measured at 17 kWh/kg of H_2 produced, leading to a net hydrogen production efficiency of 46.5% HHV H_2 (84.81 kWh/ kg H_2) on average for sustained full load operation.
- The OEM rated water consumption rate was specified at approximately 2.4 gals/hr. Actual measured water consumption at full load was found to be 3 gal/hr. The difference is water losses to the ambient through venting of humid gases and evaporation.
- At full throughput, the hydrogen flow rate out of the electrolyzer system would swing dramatically, but this flow pattern vanished at lower load conditions. An inverse pattern in stack current was observed, where stack current was constant at full load condition, and ramped intermittently to carry out purge processes with the additional hydrogen flow.
- The mass flow controller accurately controlled the hydrogen output as expected but resulted in erratic power consumption profiles at part load on minute-to-minute time-scales. On a ten-minute time-scale basis, the system power consumption profile began to smooth to the desired result.
- Ancillary power consumption was found to be constant across all load conditions at 2.5 kW_{el}, and as such consumed an increasingly large share of the power going to hydrogen production.
- The efficiency of the AC/DC power electronics did not vary on average with the system load condition. The range of observed efficiencies did increase with lower load conditions, due to the high transients in stack current.

- The electrolyzer system successfully load-followed four weeks of solar PV, each week taken from a different season. The two extremes in transients and capacity factor were the seasons of winter and spring which the electrolyzer system accomplished without issue.
- Electrolyzer system capacity factor did not lead to significant impacts on system efficiency between the different solar load following cases, which remained in the regime of 51-53% HHV H_2 (77.25-74.42 kWh/ kg H_2) . Overall capacity factors highlighted the issue with coupling energy storage systems solely with PV, with electrolyzer capacity factor going as low as 15.89% in the winter case and only as high a 38.07% for a 1:1 scale between the two systems.
- Three weeks of aggregated wind farm load following operation were carried out successfully in one continuous run, and achieved a minimum H_2 output of 0.03 kg/hr, system power consumption of 14 kW_{el}, and minimum sustained current density of 0.14 A/cm^2.
- Lower minimum load conditions combined with lower overall system capacity factors during the wind load following operation lead to system efficiencies as low as 31.07% HHV H_2 (127.23 kWh/ kg H_2) for one week, but as high as 51.35% for another (76.58 kWh/ kg H_2).
- The minimum start-up time requirement from a cold, or de-energized state, for the electrolyzer system was determined to be just under five minutes. From a 'warm' or energized state, the dynamic response of PEM electrolyzers is more than sufficient to meet even the most extreme power transients in a VRES load-following capacity, and likely at shorter time-scales by proper design and control of the AC/DC conversion equipment (e.g., for voltage support or frequency regulation). The stack was observed ramping >90% maximum operating current regularly both up and down on a second-to-second basis.
- A novel control strategy was developed involving turning off the electrolyzer system when the control signal went below 14 kW_{el} of total power consumption (corresponding to the minimum sustained power consumption for the system). This novel control strategy lead to dramatically improved system efficiency even when considering start-up times and hydrogen losses to system start-up and shutdown. System efficiency with this control strategy was around 55-56% HHV H_2 consistently, only requiring 10 power cycles per week for the wind load following profiles. The trade-off for the improvement

in system efficiency (11% improvement on average) was a loss of capacity factor on the order of 10%.

- Performance of the electrolysis process itself was most influenced by current density, temperature, and hydrogen pressure. Stack current density reduces the efficiency of the process largely due to Ohmic losses in the cell stack. Higher operating temperatures improves stack efficiency largely through improving the conductivity of the electrolyte and reducing the reversible voltage of electrolysis. Increasing hydrogen pressure increases the reversible voltage, leading to lower efficiency.
- System level efficiency was most influenced by current density and hydrogen pressure, as well as oxygen pressure to a lesser extent. A positive correlation between current density and oxygen pressure made the influence of oxygen pressure unlikely.
- Hydrogen losses were most influenced by current density and hydrogen pressure. The congruency between hydrogen loss and system efficiency influencing factors is a result of the dominance of hydrogen loss as a source of efficiency loss. At lower current densities, the proportion of hydrogen produced versus hydrogen lost increases. The majority of hydrogen loss was associated with dryer operation, controlled by an orifice flowing a slipstream of hydrogen from the active dryer bed to the inactive bed to regenerate the bed. As a result, hydrogen losses to the dryers are a function of hydrogen pressure, and largely fixed regardless of system load condition.
- Characterization of electrolyzer system losses across all load conditions showed that while at load conditions of 50% and higher (>1 A/cm^2), the majority of the energy that goes into producing hydrogen goes to the stack. Below this load condition, hydrogen losses and ancillary power demands begin to take an increasing share of energy input. Below 0.6 A/cm^2, the amount of energy input towards producing hydrogen climbs exponentially, with observed specific energies as high as 500 kWh$_{el}$/kg H_2 at 0.5 A/cm^2, as opposed to 100 kWh$_{el}$/kg H_2 at 0.6 A/cm^2.
- No statistically significant degradation of system efficiency or system components was observed during the 4000 hours of operation. There was some possible degradation in the cell stack, although only on the order of 25±20 mV/cell.

3.3.2 Recommendations

This study served to highlight the current technical viability of the power-to-gas energy storage concept when using commercially available equipment. As this study was centered on a pilot plant of an emerging energy storage concept, much of the recommendations concern the need for more concentrated studies of certain aspects of the power-to-gas plant.

- Large, controllable AC/DC power electronics for dynamic dispatch of electrolysis stacks are needed for more effective control of electrolyzer systems. The mass flow control dispatch of electrolyzer systems developed and deployed in this work enables load following capabilities on minute to minute time scales, which does not complement the PEM technology’s ability to respond on the seconds to sub-seconds time scales. Due to the rapid dynamic response capabilities of the PEM stack, improved AC/DC power electronics could enable a number of electrical grid ancillary service capabilities.
- Thermal conditioning requirements of PEM electrolyzer systems should be considered from a system efficiency perspective.
- Electrolyzer system configurations for pipeline injection end-use are needed for eliminating the large parasitic loss to PSA drying of hydrogen gas, as only certain high purity applications of hydrogen need such extensive drying.
- Electrolyzer system load following of high power transients should deploy the control strategy developed herein to turn off the system rather than idle (or operate at low production levels) when the load following signal goes below a determined minimum system power consumption requirement of the system.

4 Characterization of Electrolyzer Performance

4.1 Electrochemical Parameter Identification

Experimental data from the 60kW C10 electrolyzer was used in conjunction with the electrochemical model to determine the unknown electrochemical parameters; membrane conductivity, cathodic exchange current density, and anodic exchange current density. This was accomplished by using the trust region methods for parameter identification available in the Matlab optimization toolset. A similar approach has been used in [79] [80], and has proven effective when a wide range of experimental data is available.

Data for four different temperature set points (40C, 45C, 50C, 55C) at 30 barg cathodic pressure was used for the parameter fitting. Anodic pressure cannot be fixed, however it varied very little. The average anodic pressure of 1.6 barg was used in the parameter identification. As temperature is not perfectly controlled by the chiller, and anodic pressure did deviate, only I-V points that occurred at ±1 Celsius from the desired temperature reading, and ±0.2 barg at the anode, were included. As the electrolyzer was not able to vary the cathode pressure over a large range, the effects of pressure on these parameters were not examined, however previous studies in this area only found slight influences of pressure on these parameters, even with ranges of 7 barg up to 70 barg in the cathode [81]. The influence of pressure on the Nernst voltage described completely any additional overvoltage correlated with higher partial pressures of hydrogen or oxygen gas in the cathode and anode respectively.

The results of the curve fit are shown below in Figure 55,

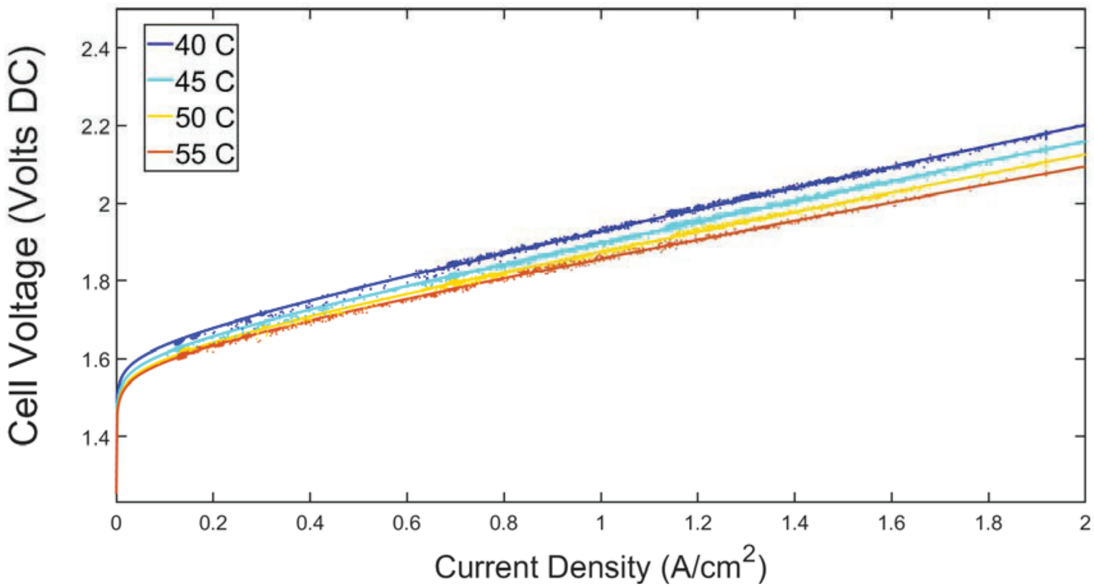
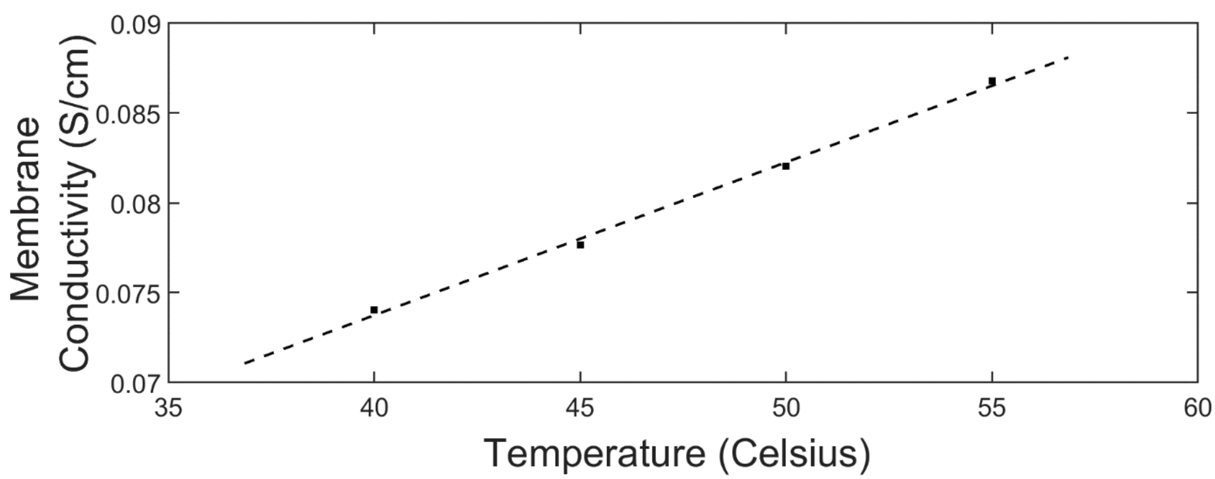


Figure 55. Fitted polarization curve agreement with input experimental data

The resulting values for each parameter are displayed in Figure 56. The strong dependence on temperature for the anode exchange current density and membrane conductivity agrees well with literature, as does the low temperature dependence in this small temperature range in the case of cathodic exchange current density [79] [80] [81].



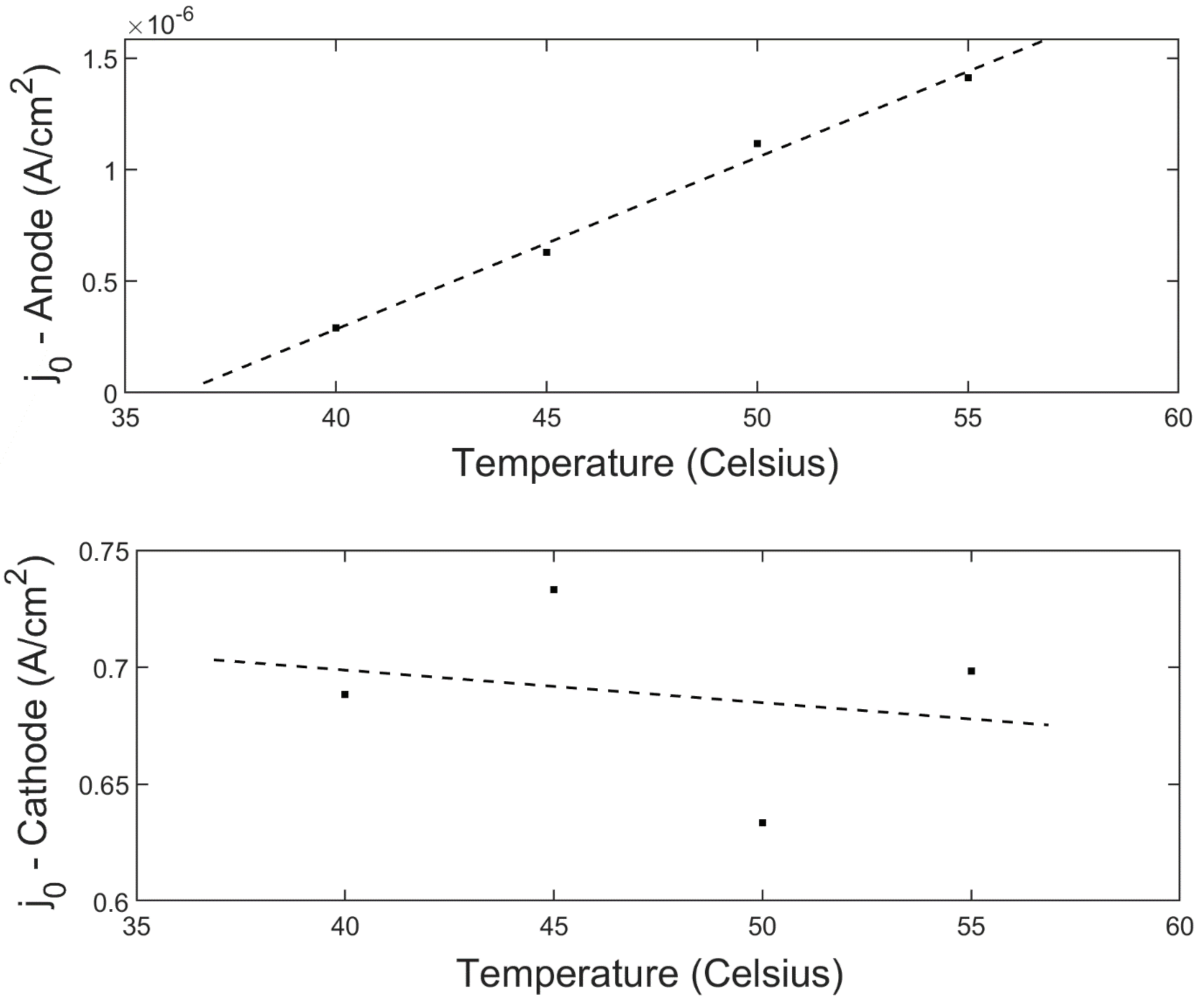


Figure 56. Dependence of electrochemical parameters on temperature

For the final electrochemical model, membrane conductivity and anode exchange current density were determined using the linear fit correlation with temperature found above. The mean of the cathode exchange current densities was used to determine the final cathode exchange current density.

$$\sigma_{mem} = 0.000852\mathrm{T} + 0.03967 \;\; [\mathrm{Siemens/cm}]$$

$$\mathrm{j}_{o,an} = 7.703426 \times 10^{-8}\mathrm{T} - 2.7966 \times 10^{-6} \; [\mathrm{A/cm^2}]$$

$$\mathrm{j}_{o,cath} = 0.688356 \; [\mathrm{A/cm^2}]$$

Figure 57 shows the contribution of the various overvoltage to the polarization curve using the final fitted parameters for average stack operating conditions. Activation overpotential at the anode dominates at low current density due to the slower kinetics of the oxygen evolution reaction (OER), and Ohmic overpotential takes up an increasing share at higher current densities due to the linear Ohmic losses.

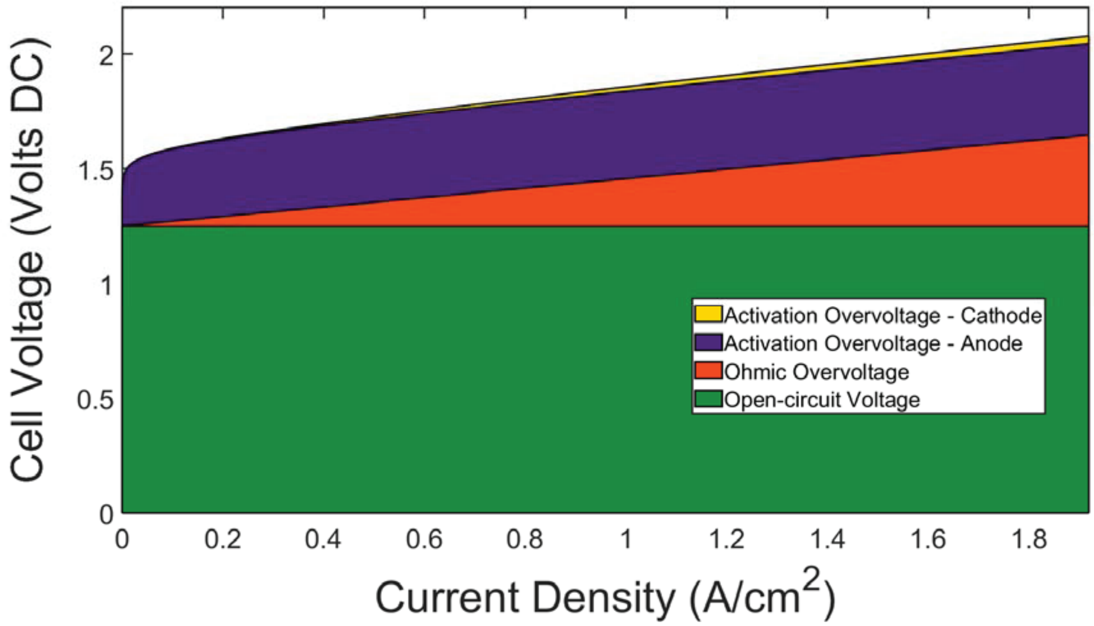


Figure 57. Breakdown of additive overvoltage contributions to polarization curve using experimentally determined parameters, concentration omitted as contribution was negligible (T_{stk} = 55 C, P_{cath} = 30 barg, P_{anode} = 1.6 barg).

4.2 Product Hydrogen Loss & Gas Cross-Over

From a system perspective, there are several pathways through which product hydrogen loss occurs. Generated hydrogen can be predicted from Faraday's law of electrolysis. Some losses occur due to cross-over of gaseous species in the electrolyzer stack. Dissolved hydrogen gas in the water flow from the cathode is circulated back to the anode feed water. Higher pressures in the cathode compartment lead to appreciable quantities of hydrogen in the cathode water, however near ambient pressures combined with long residence times at large volume tanks in the water recovery loop leads to much of the hydrogen dissipating to the atmosphere before it makes its way back to the anode feed water. A significant source of hydrogen loss comes from the operation of the PSA dryer system. Throughout operation, a slipstream of dry hydrogen from the working bed is flowed through inactive bed to purge accumulated moisture. Some product hydrogen is also likely lost due to leakage through the joints in the process piping. The end result of these effects is that the product hydrogen measured at the system outlet is far lower than the hydrogen generated due to electrolysis. These loss pathways are summarized in equation (3) and Figure 58 below.

$$\dot{m}_{H2,produced} = \dot{m}_{H2,generated} - \dot{m}_{H2,soluble} - \dot{m}_{H2,Dryer} - \dot{m}_{H2,Cross} \quad (3)$$

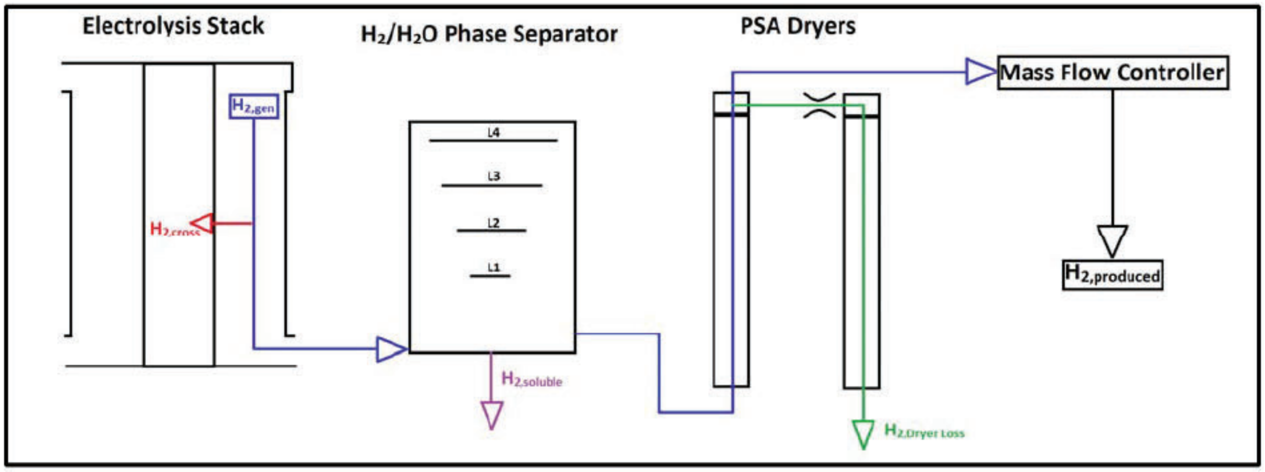


Figure 58. Product hydrogen loss pathways.

4.2.1.1 Solubility

The contribution of dissolved hydrogen in the cathode water recovery stream to overall hydrogen losses was estimated using Henry's Law for steady state conditions. The Henry's Law constant was determined as $K_H = 75253 \text{ bar} \cdot \frac{mol\ H_2O}{mol\ H_2}$, interpolated from experimental data for the temperature range of interest from two studies of pressure dependence on hydrogen solubility in pure water [82] [83]. In combination with the drain valve behavior data used to estimate the cathode water flow rate out, the net hydrogen loss to this mechanism can be estimated. The amount of dissolved hydrogen gas that contributed to the observed concentration in the anode due to feed water recirculation is determined using solubility of hydrogen at atmospheric pressures.

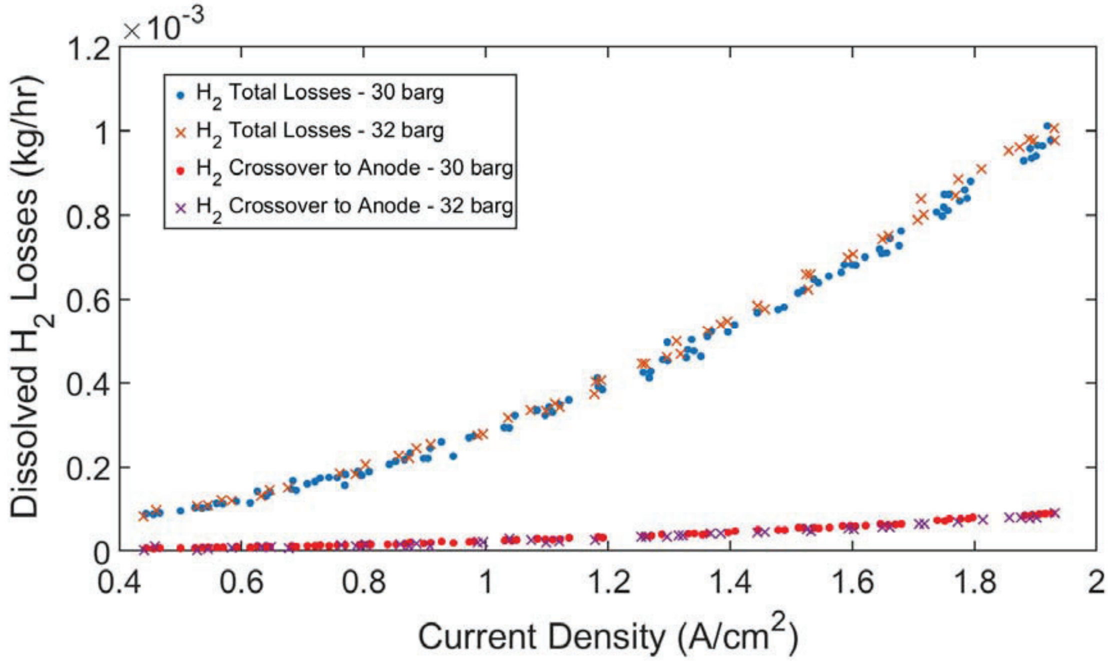


Figure 59. Hydrogen loss & hydrogen transport to the anode due to dissolved hydrogen entrained in water recovered from the cathode outlet.

Figure 59 shows the estimated hydrogen loss to the cathode water recovery process. Sustained part load operation was used to establish as close to steady state conditions as possible, for hydrogen pressure set points of 30 barg and 32 barg. At most, approximately 1 gram per hour is lost, equivalent to 0.1% of the generated hydrogen flow. Of this loss, an estimated 0.09 grams per hour at most is transported to the anode. The concentration of anodic hydrogen attributable to transport of dissolved hydrogen can be estimated from equation (4). Figure 60 below shows the estimated contribution of this transport mechanism to anodic hydrogen concentration versus measurements of hydrogen concentration in the anode, and highlights order of magnitude between the two.

$$\%H_{2,an,sol} = \frac{\dot{m}_{H2,sol,an}}{\dot{m}_{H2,sol,an} + \dot{m}_{O2,gen}} = \frac{\dot{m}_{H2,sol,an}}{\dot{m}_{H2,sol,an} + \frac{n_{cells}jA}{4F}} \quad (4)$$

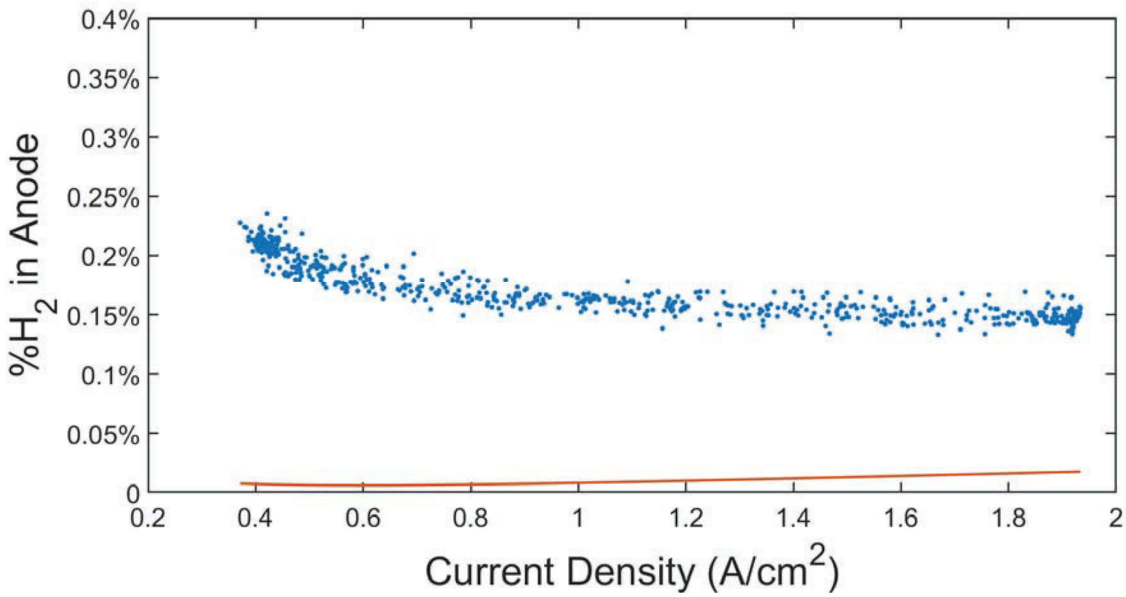


Figure 60. Estimated percentage of hydrogen content in anode due to solubility (Orange) versus observed values (Blue).

4.2.1.2 Orifice/Dryer

Hydrogen loss to the PSA dryer beds is flow restricted by an 0.18 mm orifice, rated at a maximum nominal flow rate of 13.8 SLPM H_2 at 30 barg H_2, equivalent to 0.0744 kg H_2/hr. Since the downstream pressure is effectively atmospheric, choked flow conditions are established, and the dryer flow as a function of varying hydrogen pressure can be estimated using equation (5) from Crowl & Louvar [84].

$$\dot{m}_{H2,Orifice} = C_d A_O P_{H2} \sqrt{\left[\left[\frac{kG_c M_{H2}}{RT}\right]\left[\frac{2}{k+1}\right]^{\left(\frac{k+1}{k-1}\right)}\right]} \tag{5}$$

For the rated flow rate of 0.0744 kg H_2/hr at 30 barg, the discharge coefficient is determined to be $C_d = 0.42$. Using the relation between hydrogen pressure and orifice mass flow, the dryer losses are estimated as a function of H_2 pressure and orifice flow uptime (~roughly 91.5% of the time on average). Figure 61 below shows the predicted losses due to solubility of hydrogen in recovered cathode water as well as dryer losses versus the generated hydrogen output (Faradaic basis) and the observed hydrogen output. It can be seen that the estimated system losses account for the majority of the discrepancy in hydrogen output from the observed measurements.

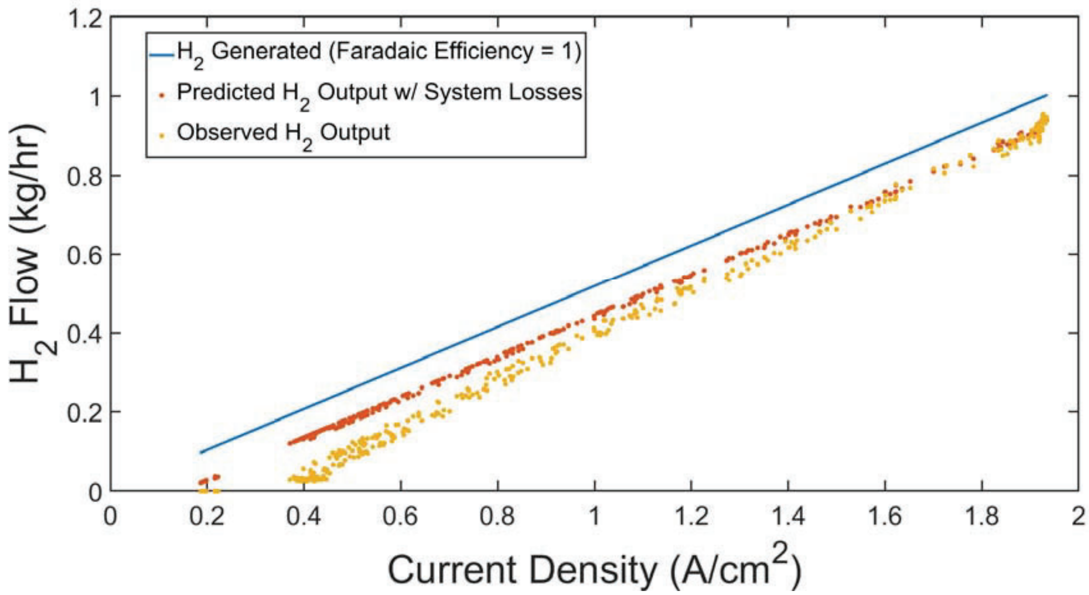


Figure 61. Comparison of net generated hydrogen at stack versus predicted hydrogen output after dryer and solubility losses versus observed hydrogen output.

4.2.1.3 Cross-over

Cross-over of product gaseous species in the electrolyzer cell stack occurs as a result of the chemical potential gradient across the polymer electrolyte, which itself is a result of the pressure gradient. Mass transport of gaseous species across the electrolyte is primarily driven by diffusion [47] [85]. In the case of the C10 electrolyzer system, which operates at pressure differentials of as much as 30 barg from cathode to anode, safety is considered a potential concern, particularly at low current densities where oxygen production slows down in the anode, while pressure-driven diffusion of hydrogen remains relatively constant, leading to higher concentrations of hydrogen gas in oxygen gas. The lower explosive limit of hydrogen gas is 4% by volume in O_2 and air [86], requiring stringent mitigation of mixing for the two product gas species.

Hydrogen content in the anode stream is measured by combustible gas detector at the oxygen-water phase separator tank for purposes of safety. The combustible gas sensor requires regular calibration, as well as having relatively poor error range (±10% accuracy at 25 Celsius), and as such the measurements are not an accurate measure of hydrogen gas present. Hydrogen concentration in the anode side is typically around 0.16% on a volumetric basis, equating to roughly 4% of the LEL of H_2 in oxygen or air. At lower current densities, an increase in hydrogen concentration is observed as the rate of oxygen production drops, while hydrogen transport across the electrolyte to the anode remains relatively constant, reaching concentrations as high as 0.25% by volume, or 6.25% of the LFL of H_2, well within safety limits.

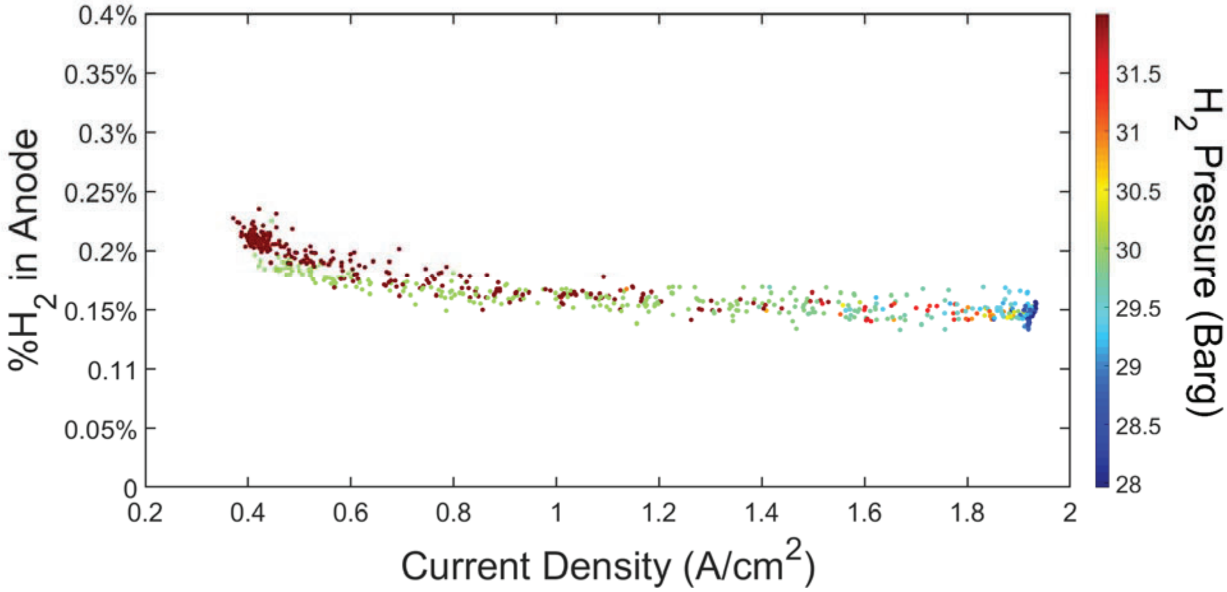


Figure 62. Observed percentage of hydrogen gas in the anode product stream.

The amount of hydrogen gas that crosses over from the cathode to the anode in the electrolyzer stack is estimated via two different approaches; a 'top-down' estimate and a 'bottom-up' estimate. In the 'top-down' estimate, hydrogen losses unaccounted for by the dryer and dissolved hydrogen gas losses are assumed to be accounted as cross-over losses. In the 'bottom-up' estimate, the anodic hydrogen content is used to estimate the concentration of hydrogen exiting the anode stream.

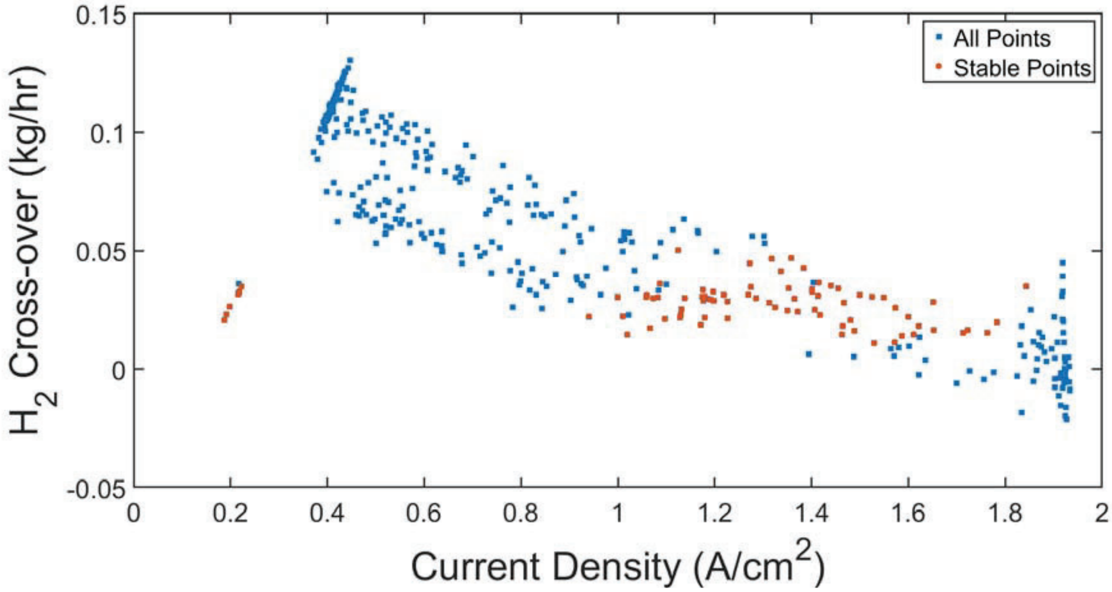


Figure 63. Observed 'unaccounted' for hydrogen losses, with stable points utilized for the top-down estimate of hydrogen cross-over.

Figure 63 shows the 'unaccounted' for hydrogen losses considered for the top-down estimate of hydrogen gas cross-over losses. Due to the transient nature of the pressure driven controls, points that were collected with high pressure transience over the sampling period were eliminated for this analysis. This occurred primarily in two regimes. At operating conditions below 1 A/cm^2, the average pressure downstream was typically higher than the upstream pressure, resulting in likely greater but unquantifiable losses to the dryer orifice. The exception to this regime occurred at 'zero-flow' points, where the pressure regulator remained closed; Figure 63 illustrates these points in the lower left. At near full out operating conditions, H_2 pressure fluctuated dramatically, similarly impacting estimations of dryer orifice loss. The points ultimately used are highlighted in Figure 63.

Two coefficients, diffusive permeability, $\varepsilon_{H2}\left[\frac{mol\cdot sec}{cm\cdot bar}\right]$, and the H_2 partial pressure enhancement coefficient, $A_{H2}\left[\frac{bar\cdot cm^2}{amp}\right]$, are needed to describe the hydrogen diffusion transport across the membrane as a function of the partial pressure of hydrogen and the current density. Linear regression was used to fit the two coefficients to the experimental data, resulting in $\varepsilon_{H2} = 1.76 \times 10^{-10}\left[\frac{mol\cdot sec}{cm\cdot bar}\right]$ and $A_{H2} \approx 0$. A H_2 partial pressure enhancement factor of near zero occurred due to lack of correlation with current density, suggesting effective mass transport of hydrogen species away from the electrode-electrolyte interface (Figure 64). As a result, hydrogen cross-over was estimated to only be a function of the partial pressure of hydrogen in the cathode, as was found to be the case in the majority of the literature reviewed concerning gas gross-over in PEM electrolysis [85] [87] [88]. This correlation with the 95% confidence intervals is displayed below in Figure 64.

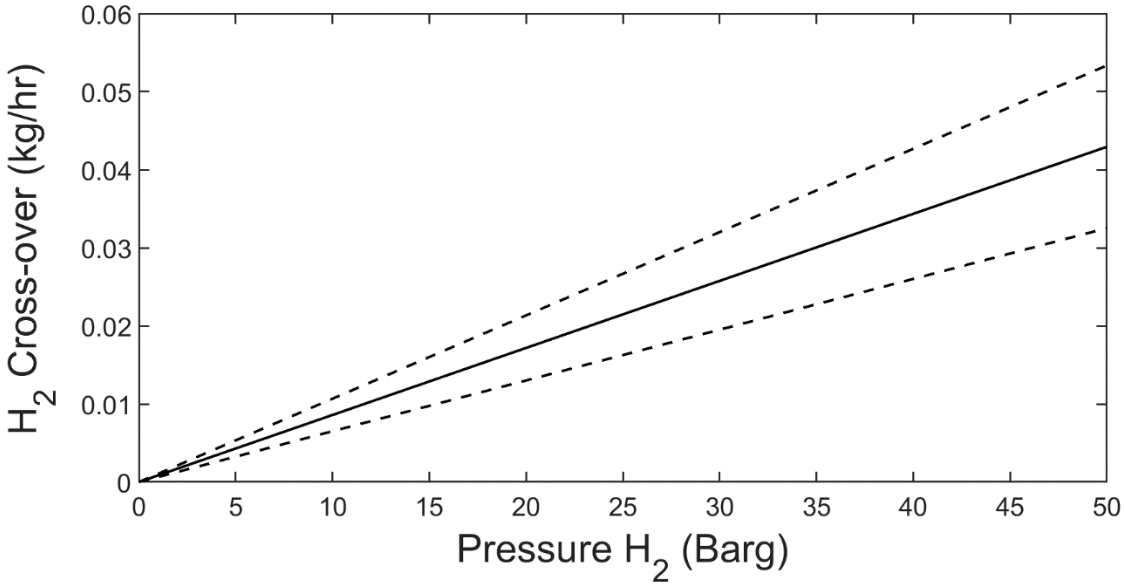


Figure 64. Top-down estimate of H_2 cross-over, function of cathodic H_2 pressure; $\varepsilon_{H2} = 1.76 \times 10^{-10} \left[\frac{mol \cdot sec}{cm \cdot bar}\right]$. 95% confidence intervals in dashed lines.

The end result of the top-down estimate is shown below in Figure 65. The trend of hydrogen concentration varying with current density is similar to what was actually observed (Figure 62), however there is a two order of magnitude separation between the top-down estimated hydrogen concentration and the measured hydrogen concentrations.

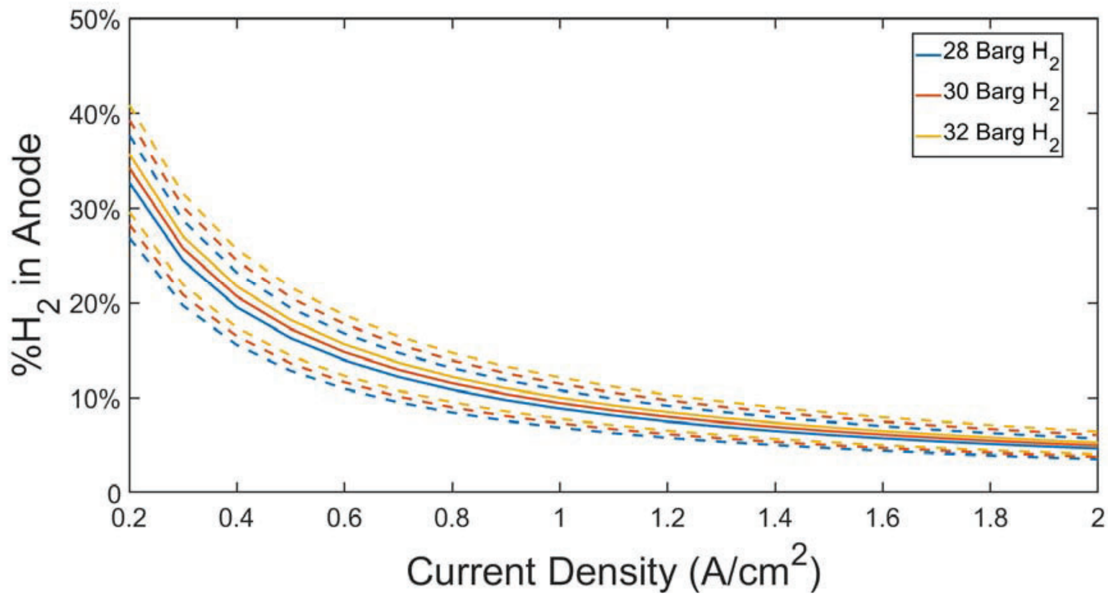


Figure 65. Percentage of hydrogen gas in anode predicted by top-down estimate of hydrogen gas cross-over.

From a 'bottom-up' perspective, the amount of hydrogen cross-over can be estimated using the observed hydrogen concentration values in the anode (Figure 62). Figure 66 shows the points used for the bottom-up estimate from anodic hydrogen concentration for hydrogen cross-over. There is a clear enhancement in cross-over from higher pressures as expected and likewise observed in the top-down estimate. There is a far stronger agreement with the linear correlation between cross-over and current density described by the pressure enhancement factor A_{H2}.

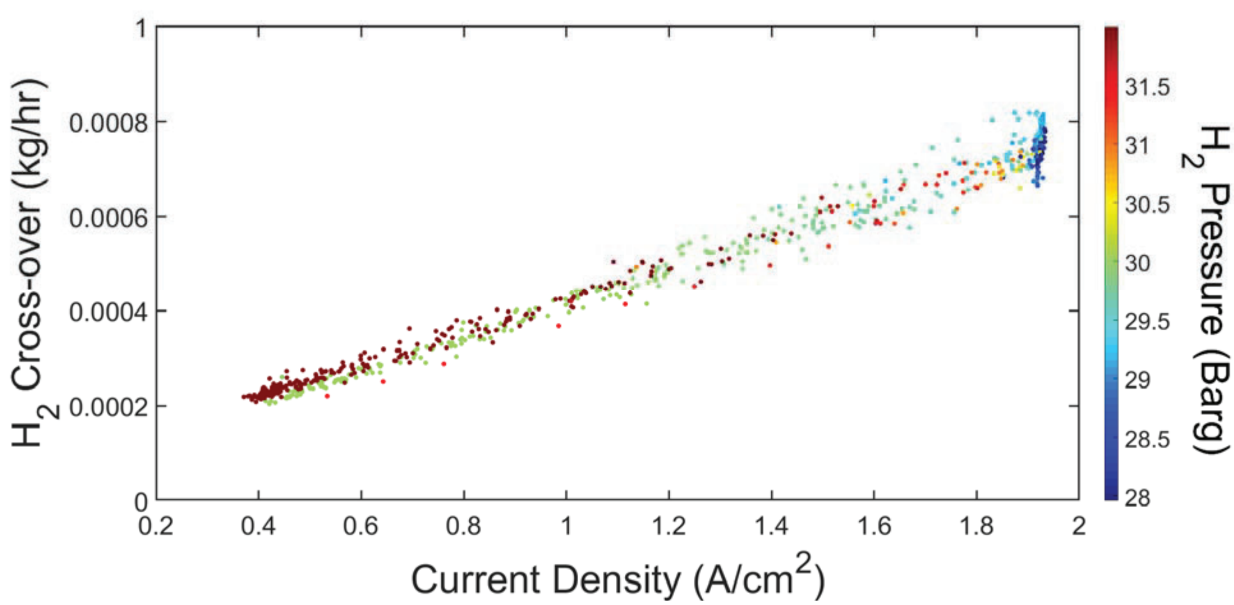


Figure 66. Bottom-up estimate for H_2 cross-over in kg/hr, with pressure correlation.

Linear regression fitting of the bottom-up estimate results in parameter fits of $\varepsilon_{H2} = 4.47 \times 10^{-13} \left[\frac{mol \cdot sec}{cm \cdot bar}\right]$ and $A_{H2} = 154.34 \left[\frac{bar \cdot cm^2}{amp}\right]$. The relationship between cross-over, hydrogen pressure and current density predicted by these parameters is shown below in Figure 67.

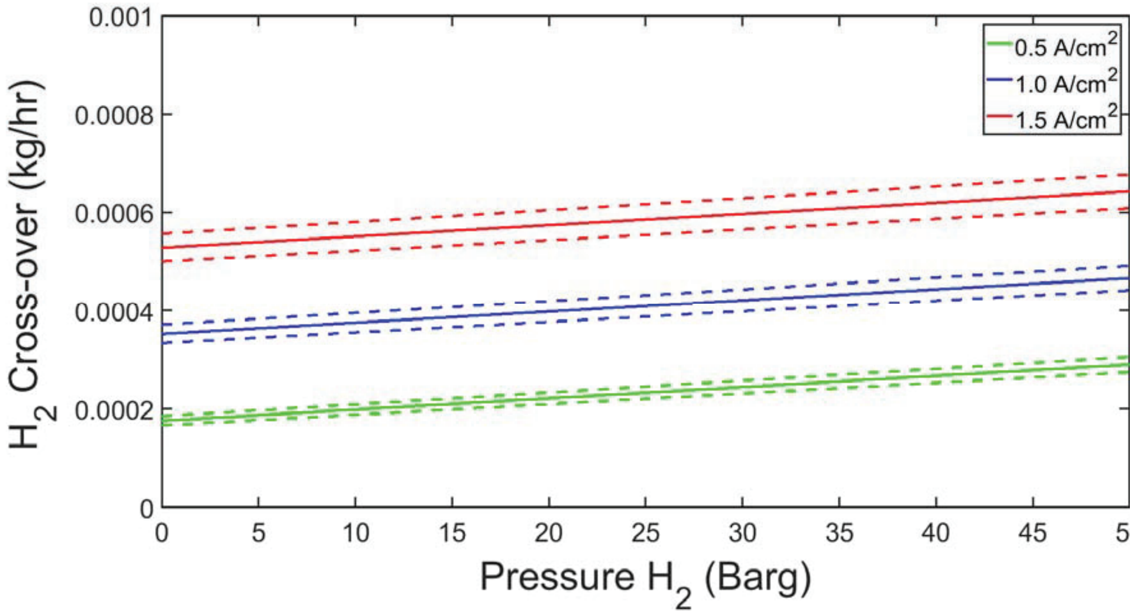


Figure 67. Bottom-up estimate of H_2 cross-over, function of cathodic H_2 pressure and current density; $\varepsilon_{H2} = 4.47 \times 10^{-13} \left[\frac{mol \cdot sec}{cm \cdot bar}\right]$ and $A_{H2} = 154.34 \left[\frac{bar \cdot cm^2}{amp}\right]$. 95% confidence intervals in dashed lines.

The value obtained for pressure enhancement factor A_{H2} is two orders of magnitude higher than what was observed by Schalenbach et al. where the correction factor was proposed [47], and similarly the diffusion coefficient was two orders of magnitude lower than what was observed.

Both methods of gas cross-over estimation suffer from a few limitations. The top-down estimate very likely overestimates cross-over by not accounting for hydrogen leakage in the system, outside of the cell stack. Additionally, the combined rated measurement error of the current transducers (used to calculate Faradaic hydrogen production) and the mass flow meter (used to measure the system hydrogen output) is ~0.02 kg/hr, on the same order of magnitude as the 'unaccounted for' hydrogen loss used in the top-down gas cross-over estimate. However, the repeatability of hydrogen measurements through multiple rounds of calibrations over the testing period suggests that this measurement error range is much tighter than the specified error for both the current transducers and mass flow meter. Furthermore, sustained 'zero-flow' operation demonstrated a repeated consistent H_2 loss that follows the predicted trend, while taking the flow meter measurement error out of the equation.

The bottom-up estimate relied on two assumptions. First, that hydrogen gas in the anode was largely inert. For IrO_2 catalyst typically employed in PEMEZ anodes, it is assumed that no hydrogen reacts electrochemically with oxygen [47], or that there is no secondary catalytic combustion of hydrogen in the anode stream, through the use of gas recombiners [87] [85]. Secondly, it is supposed that the timescale on which measurements are taken in the anode is long enough such a steady state condition in the oxygen-water phase separator volume is achieved. At the lowest oxygen flow rate, the amount of time for the volume to be fully exchanged is 3 minutes 15 seconds, and all measurements used were made at sustained 10-minute intervals. Some transients occurred due to dryer operation during testing, which could have had minor undue influence on the results, however these cases did not result in noticeable outliers.
Given that the assumptions for the bottom-up estimate could be invalid (particularly lack of catalytic conversion of anodic hydrogen gas), in addition to the lack of agreement in the resulting transport parameters with current literature, the top-down estimate parameters of $\varepsilon_{H2} = 1.76 \times 10^{-10} \left[\frac{mol\cdot sec}{cm\cdot bar}\right]$ and $A_{H2} \approx 0$ are selected for the analytical electrolyzer model. This will serve as an over-estimate of hydrogen gas cross-over in the stack but reflects the trend properly and is likely close in magnitude.

4.2.1.4 Removal of the H_2 PSA Dryer

Having estimated the losses associated with stack cross-over, the hydrogen dryer orifice (at stable pressure conditions >50% load condition) and dissolved hydrogen in the water loop, system performance without the hydrogen PSA dryer can be estimated as well. Figure 68 compares the system's specific energy requirements measured throughout operation (with PSA) versus the projected system specific energy requirements operating without the PSA system. Measured system power consumption and estimated hydrogen throughput using Faraday's law and hydrogen losses to cross-over in the stack were used to estimate the no PSA data points. As system operation was limited due to excessive dryer losses below the 0.4 A/cm^2 (~14 kW system power) as hydrogen production approached effectively zero, the analytical model was used to extend the trend out to the expected wider range of viable operation which is 0.15 A/cm^2 (~6 kW system power). This low load condition represents a 10% total system load condition turndown, and a 8% stack load condition turndown. This could still be limited by hazardous hydrogen concentration in the anode compartment due to high hydrogen cross-over relative to low oxygen flow rates at these extremely low load conditions, however measured concentrations of H_2 in O_2

never exceeded 6% LFL (0.25% by volume total) at minimum load conditions so there was definitely still room for lower load on this basis.

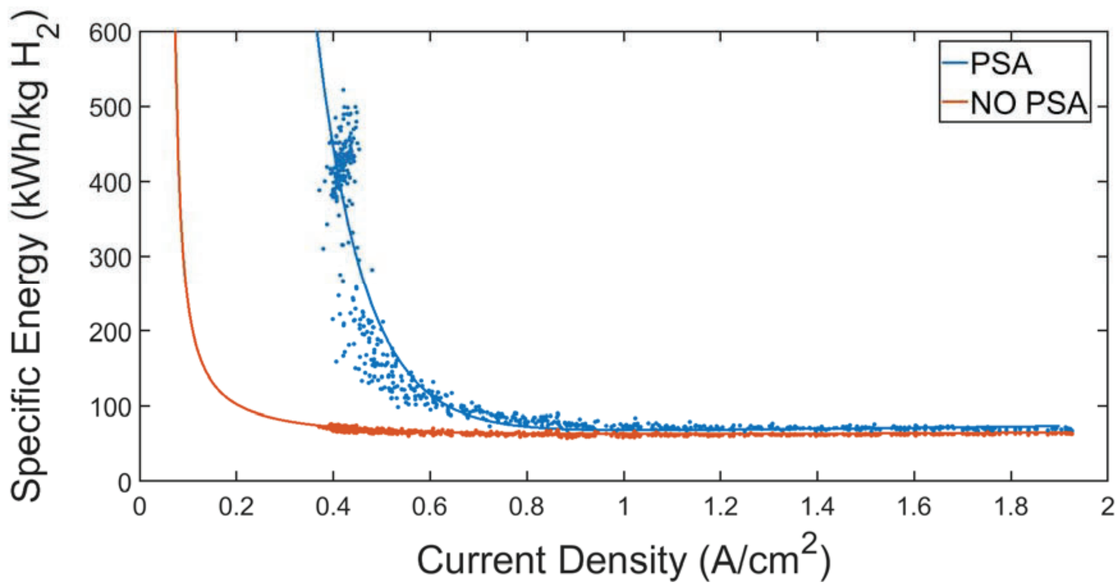


Figure 68. Effect of PSA Dryer system on system performance.

For many applications, dry hydrogen is desired (industrial end use, fueling etc). In the case of pipeline injection, there is potential for some flexibility in the moisture content of the hydrogen. Guidelines for injection of customer owned gas outlined in Southern California Gas Company's Rule 30 calls for moisture content not exceeding 7 lbs of water per million standard cubic feet (MMscf) of gas [89]. For the case of saturated hydrogen at 20 Celsius and 30 Barg entering the PSA dryer, the moisture content is approximately 39.5 lbs of water per MMscf gas. Further conditioning could be accomplished through cooling of the gas pre-injection and blending with dry natural gas for injection would further dry the overall mixture. For the 20 Celsius and 30 Barg saturated condition, blends of up to 17% by volume H_2 in dry natural gas would be within the 7 lbs water per MMscf gas limit.

When PEM electrolyzer systems are deployed for pipeline injection applications, it is readily apparent that the PSA drying system may not be necessary. Of course, Rule 30 is a regulation not intended to govern injection of hydrogen gas to the pipeline and is only chosen as an analog regulation in the absence of any pertinent standards. Furthermore, the PSA system does not have an appreciable impact on system performance until the ~50% mark in load condition, such that in the absence of high dynamic load conditions for the electrolyzer system, it may still be worth keeping the system for ease of operation and flexibility in hydrogen end-use that the extensive purification process provides. Larger PEM systems would also mitigate the performance loss associated with the PSA dryer, though to what extent is unclear.

4.3 Semi-empirical Thermodynamic Model of PEM Stack

A steady-state stack model is developed that incorporates 0-D species transport. This is accomplished by creating an overall ‘pseudo’ steady-state electrolyzer model, wherein the electrochemical response is assumed to be fast enough in PEM electrolyzers such that transient effects would be minimal on the time scales of interest for our application. This is apparent from the results of the electrolyzer system dynamic operation testing.

Due to the presence of a chiller for thermal management on the electrolyzer considered in this modeling effort, the stack model is assumed isothermal. Additionally, a pressure regulator maintains relatively even pressure on the hydrogen side, and experimental measurements have demonstrated that the anode side sees very little variation in pressure, so an isobaric condition is utilized at each respective electrode. This allows for pressure-driven transport phenomena across the electrolytic membrane to be analyzed, and species transport out of the cells can still be determined by molar balance in and out of the cell by assuming zero storage. For modeling efforts seeking to incorporate a PEMEZ model, this approach should allow for a realistic scenario wherein a real electrolyzer system would operate based on temperature, pressure, and power set points, and would be expected to deviate very little from the set points during operation. In combination with the mass transport models, also provide a more accurate system efficiency and species output than a simplified electrochemical model.

A dynamic load model sends a current value to the electrochemical based stack model at a time t. Operating pressures, stack temperature, and water flow rate are set in the stack model. For the exercising of the stack model to compare against experimental data, the pressures of the cathode and anode, as well as the stack temperature, that were measured alongside the current, will be sent to the stack model to assess how accurate the electrochemical model is. The stack model returns the cell voltage, species transport out of the anode and out of the cathode, and the pressure and temperature of the cathode outlet stream. With the current balance of plant on the C10 electrolyzer, temperature and pressure deviate very little from the set points, such that this model can capture with modest accuracy the output and efficiency of the electrolyzer stack with a fixed temperature and pressure against the slight deviations experienced by the system.

This PEM electrolyzer stack model can be applied in a number of applications for power-to-gas studies, providing information on the mass flows out of a PEM system based on dynamic electrical load inputs. Modern PEM systems utilize the pressure regulators, thermal conditioning, and power electronics that justify the isobaric, isothermal, and DC current based input assumptions of the model, making it flexible in application across the spectra of PEM systems. Figure 69 shows the information flow of the model as well as possible applications of the model, such as integration with hydrogen compression or liquefaction systems for application to pipeline injection, tank filling (for applications in back-up power and vehicle fueling), and geological storage.

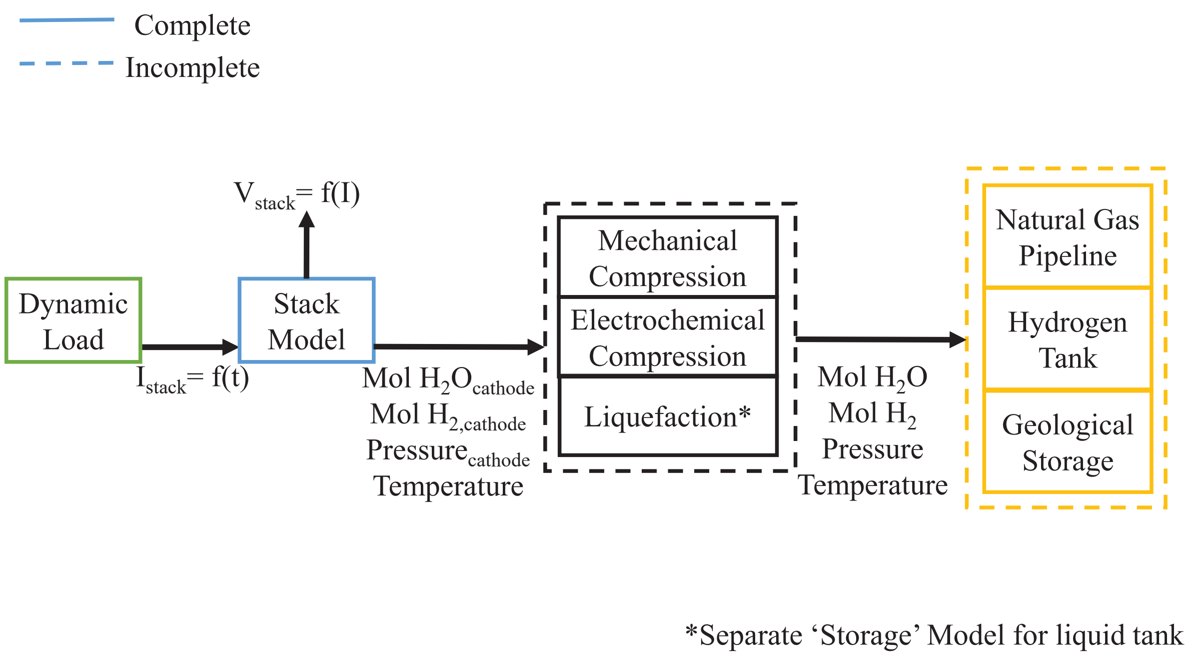


Figure 69. Semi-Empirical PEM Stack Model with Possible Applications for future studies.

Table 11 summarizes the values of key parameters associated with the species transport that was either provided by Proton OnSite (dimensional parameters such as porosity, $\boldsymbol{\varepsilon}$ and thickness $\boldsymbol{\delta}$ of the membranes and electrodes) and species constants not determined from this study and instead taken from literature involving similar stack configurations and conditions.

Table 11. Identified Stack Parameters associated with species transport

A (cm^2)*	213.68	$\boldsymbol{\delta_{mem}}$**(cm)***	0.0178
$\boldsymbol{\delta_{an}}$* **(cm)**	0.13	$\boldsymbol{\varepsilon_{mem}}$	0.3 [74]
$\boldsymbol{\varepsilon_{an}}$*	0.50	**n (#cells)**	65
$\boldsymbol{\delta_{cath}}$ * **(cm)**	0.13	$\boldsymbol{\varepsilon_{O2,diff}}$ **(mol/cm s bar)**	2.00×10^{-11} [47]

ε_{cath}*	0.65	$\varepsilon_{H2,perm}$**(mol/cm s bar)**	0 [88].

*Values provided by Proton Onsite, specific to the C10 Electrolyzer Stack

4.3.1 Model Validation & Results

4.3.1.1 Winter & Spring Load Following

The winter and solar load following cases were selected for validating the solar PV load following capabilities as the two seasonal profiles encapsulate the two 'extremes' of solar PV dynamics observed from the physical load following tests.

Table 12 summarizes the results of the model versus the data. It can be seen that the set point approach is a fair assumption in this case, as the system stack temperature and pressures did not depart significantly from the set points. The analytical model does not account for cathodic water recovery, and thus projects dramatically greater water consumption. The percentage of cathodic water recovery is determined from this discrepancy. The model closely matched the actual system performance, with very little deviation in the projected efficiency on both the stack and system efficiency, as well as the hydrogen output.

Table 12. Solar load following cases with analytical model using set points and input current versus actual system behavior.

	Winter		Spring	
	Actual	**Model**	**Actual**	**Model**
Stack Temp (Celsius)	55.08	55	55.04	55
Cathode Pressure (Barg)	29.98	30	29.71	30
Anode Pressure (Barg)	1.72	1.5	1.83	1.5
H2O Cons. (Gallons)	80.98	360.32	166.58	751.52
Cathode Water Recovery	94.99%	--	94.66%	--
Total kg H2 Prod.	21.75	21.98	45.96	46.92
kWh/kg Stack (Faradaic)	50.32	50.29	53.10	52.97
kWh/kg System	76.31	76.48	73.19	73.67

Figure 70 and Figure 71 show the predicted stack power consumption versus the experimental data for the winter and spring solar load following cases respectively. Figure 72 shows the polarization curve agreements between data and model for these cases. These figures highlight the accuracy of the electrochemical model and the parameters obtained from fitting in determining the cell voltage.

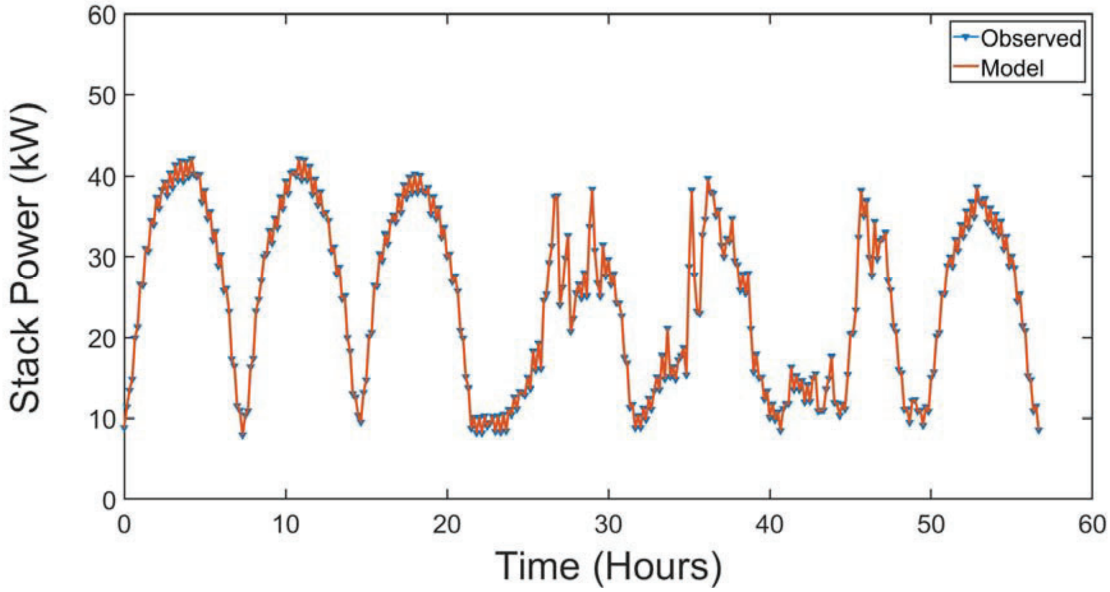


Figure 70. Stack power consumption for winter solar load following, observed data versus analytical model fit.

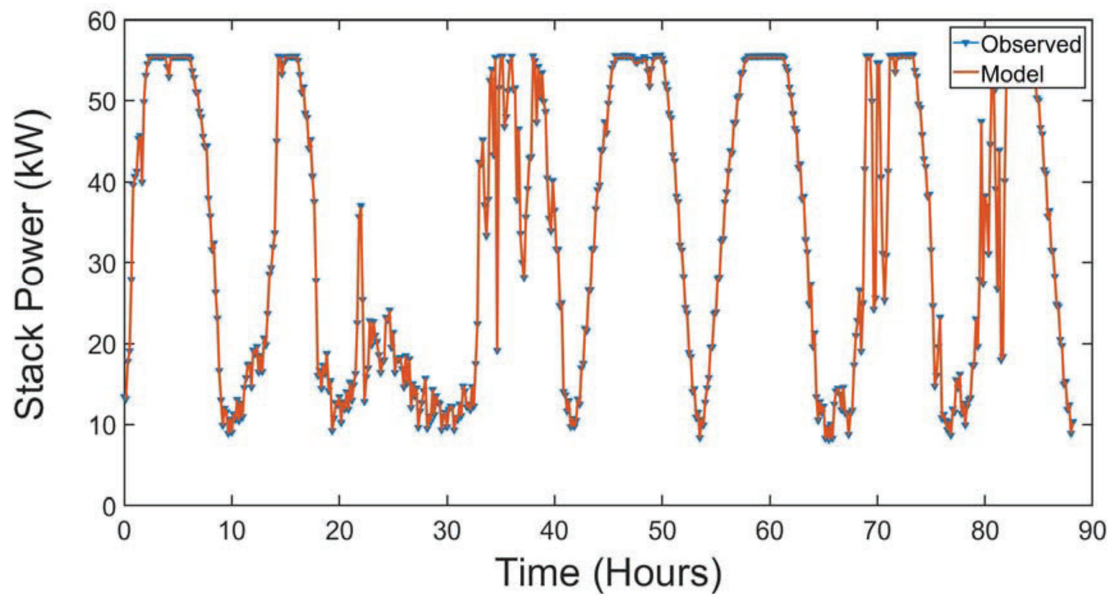


Figure 71. Stack power consumption for spring solar load following, observed data versus analytical model fit.

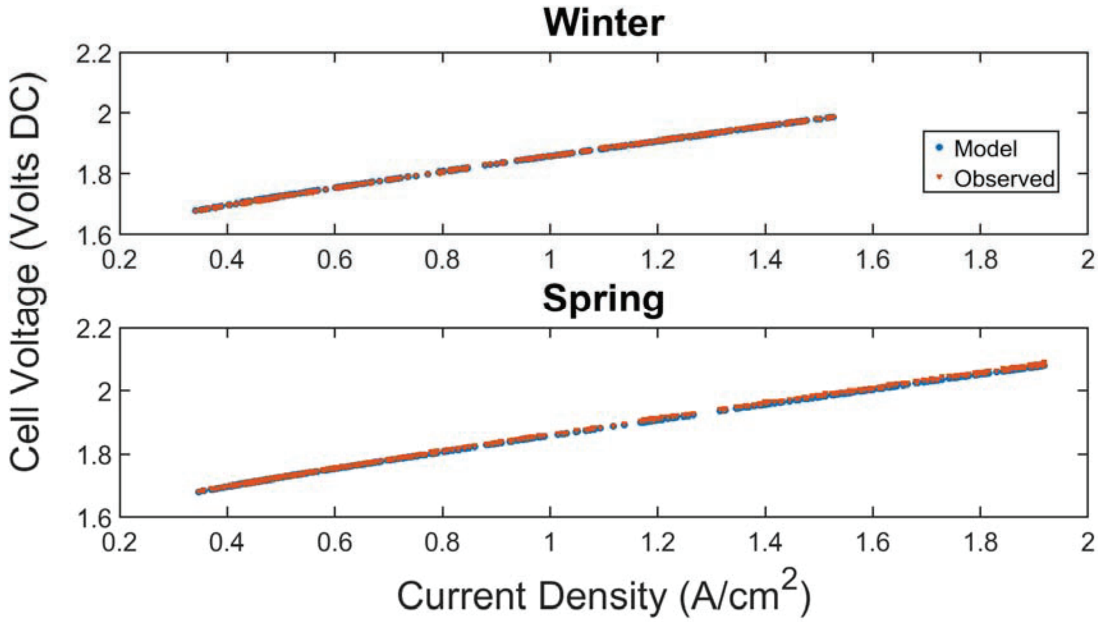


Figure 72. Polarization curve fits for winter and spring solar load following, observed data versus analytical model fit.

Net hydrogen production of the electrolyzer system matched well for the solar load following cases between the model and observations. One-hour averages of measured hydrogen output were included in Figure 73 showing the agreement between model and data. This was to highlight that while the hydrogen output deviated from the model prediction on a minute to minute basis, over longer time-scales the model prediction agreed well. An increasing degree of departure between the model and data is noticeable at increasingly lower current densities, corresponding to the 'unstable' system pressure region of operation where hydrogen flow losses to the orifice dryer becomes difficult to estimate accurately.

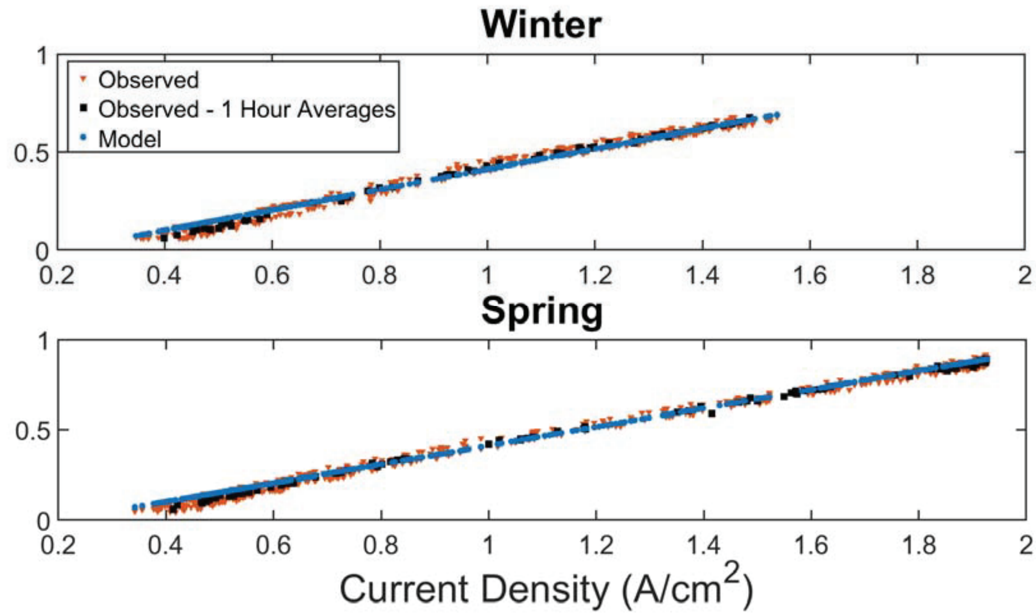


Figure 73. System hydrogen output versus stack current density for winter and spring solar load following, observed data versus model fit with 1-hour averaged observed data.

4.3.1.2 Wind Load Following

The exercising of the analytical model with the wind load following data provides for a wider range of load conditions than the solar load following case as well as a higher hydrogen pressure set point (32 barg in this case versus 30 barg in the solar load following cases). Table 13 summarizes the results of the model runs for two extremes of wind load following, and figures Figure 74 and Figure 75 show the agreement in stack power consumption for the two profiles. As opposed to the solar load following scenario, there is a noticeable departure in accuracy for hydrogen output and system efficiency particularly for the low load condition first wind case. Additionally, a nearly 1 barg difference in set point pressure versus average observed pressure can be seen in the high load wind case two. At higher flow throughputs, the pressure regulation system sees pressures closer to the injection point pressure rather than the system set point.

Table 13. Wind load following case with analytical model using set points and input current versus actual system behavior.

	Wind - 1		Wind - 2	
	Actual	**Model**	**Actual**	**Model**
Stack Temp (Celsius)	55.09	55	55.09	55
Cathode Pressure (Barg)	31.99	32	31.17	32
Anode Pressure (Barg)	1.70	1.5	1.79	1.5
H2O Cons. (Gallons)	80.50	374.49	151.52	820.85
Cathode Water Recovery	85.91%	--	89.87%	--
Total kg H2 Prod.	14.10	21.00	47.44	50.36
kWh/kg Stack (Faradaic)	47.47	47.39	52.43	52.21
kWh/kg System	147.12	96.94	82.70	77.76

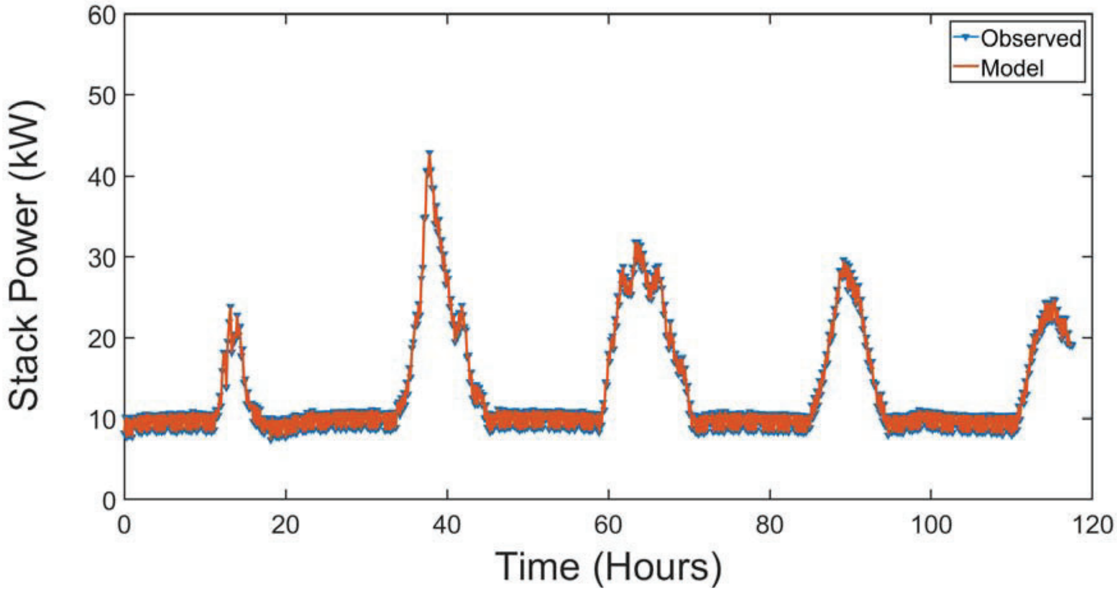


Figure 74. Stack power consumption for first half of wind load following, observed data versus analytical model fit.

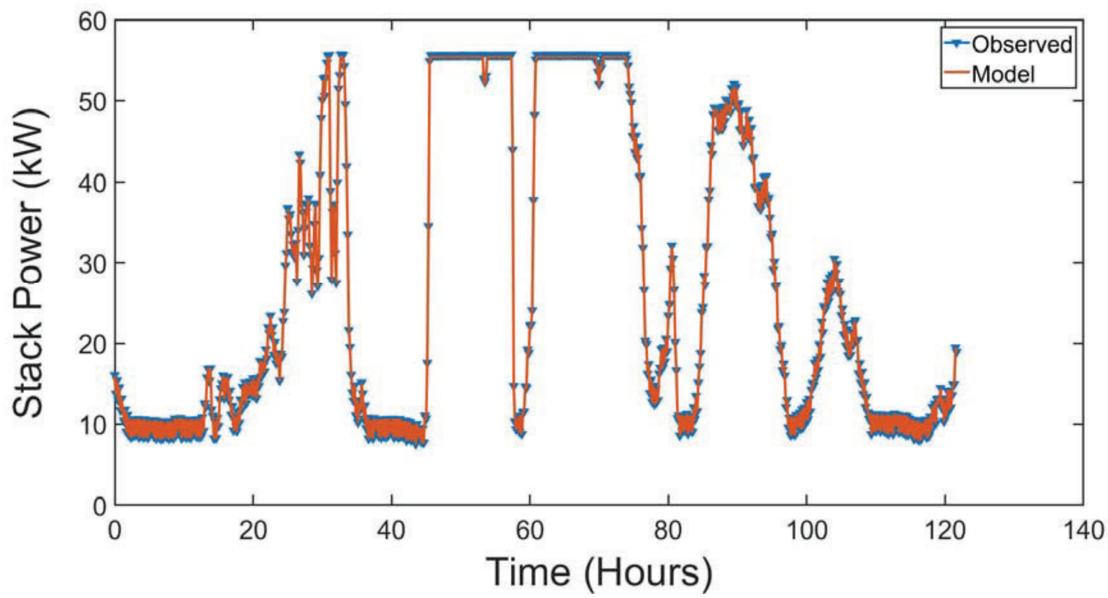


Figure 75. Stack power consumption for second half of wind load following, observed data versus analytical model fit.

Figure 76 shows the polarization curve agreement for the wind load following cases. Some departure can be seen at the higher load condition as opposed to the near perfect agreement from solar load following, but the cell voltage prediction is still accurate to within 0.5% error.

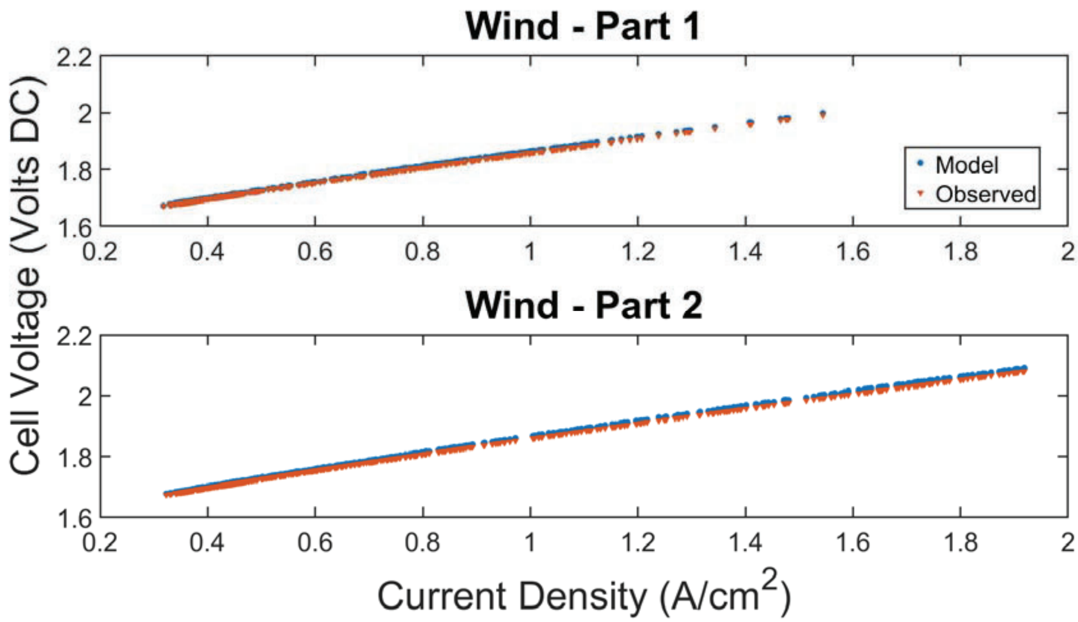


Figure 76. Polarization curve fits for wind load following, observed data versus analytical model fit.

The more extreme deviation in hydrogen output prediction by the model versus measured system performance at the low load condition can be seen in Figure 77. Once again, particularly from a longer time scale averaged perspective, the hydrogen output prediction remains fairly accurate until 0.7 A/cm^2 and below. The end result is a nearly 33% over prediction in hydrogen output for the first wind case of 14 kg H_2 measured output versus a predicted 21 kg of H_2 where the system is operating below the 0.7 A/cm^2 current density regime for 60% of the run time.

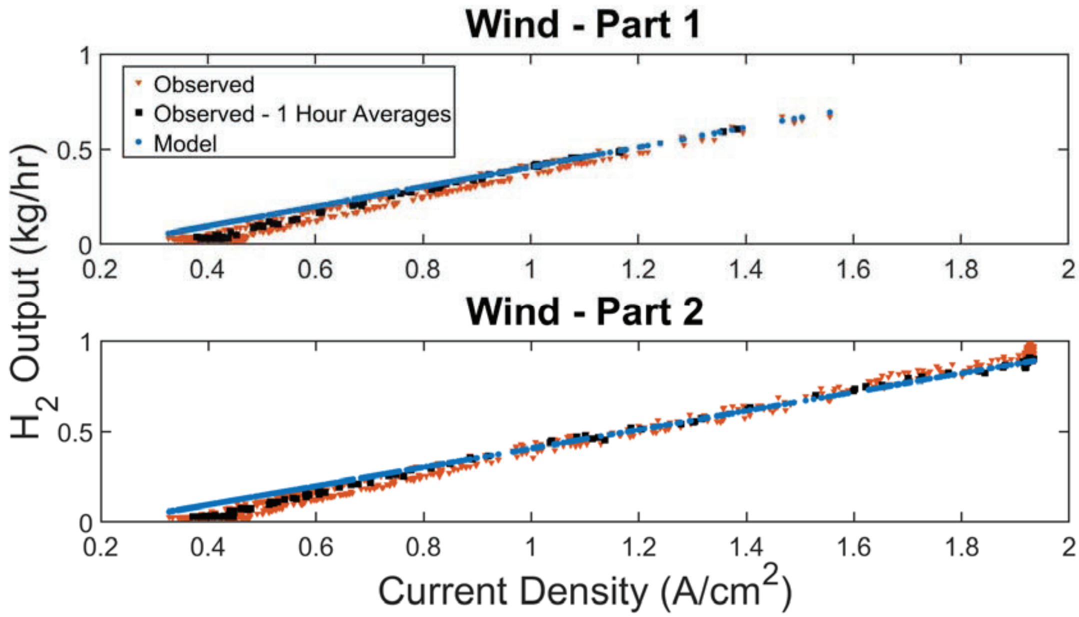


Figure 77. System hydrogen output versus stack current density for wind load following, observed data versus model fit with 1-hour averaged observed data.

4.4 Electrochemical Compression

An important aspect of hydrogen production by electrolysis is the product gas pressure of the hydrogen. Electrolyzer systems can both produce and compress hydrogen electrochemically. For most commercial electrolyzers this hydrogen compression typically does not exceed 30 barg (as is the case for the C10 electrolyzer system at the center of this study). Higher operating pressures are limited by safety and efficiency concerns due to gas cross-over in the membrane. Furthermore, accelerated chemical degradation in the stack assembly at elevated operating pressures in PEM electrolyzers is a concern [90]. Pressures of 170 barg and 350 barg H_2 (ambient pressure on O_2 side) have been demonstrated by PEM electrolyzer original equipment manufacturers Proton OnSite (now NEL) [91] and Giner [92] respectively.

Ideal electrochemical compression can be characterized as an ideal isothermal compression process, demonstrated by Maclay [93]. Ideal isothermal compression is given by equation (6) from Cengel & Boles [94], where P_2 is the outlet pressure, P_1 is the inlet pressure, R is the specific gas constant (hydrogen gas constant in this case), and T is the temperature.

$$W_{comp,isothermal} = RT \ln(\frac{P_2}{P_1}) \quad (6)$$

By isolating the voltage increase due to an increase in hydrogen pressure from the Nernst equation (7) [95], and noting the relation between voltage change and work (eq. 8), where Q is the charge and ΔV is the voltage change going from P_1 to P_2, it is evident that the two expressions are equivalent.

$$\Delta V = E_{OCV}\left(T, P_{2,cathode}\right) - E_{OCV}\left(T, P_{1,cathode}\right)$$

$$\Delta V = \frac{RT}{2F}\left[ln\left(\frac{P_{2,cathode}P_{O2,anode}^{0.5}}{a_{H2O,anode}}\right)\right] - \frac{RT}{2F}\left[ln\left(\frac{P_{1,cathode}P_{O2,anode}^{0.5}}{a_{H2O,anode}}\right)\right] \quad (7)$$

$$\Delta V = \frac{RT}{2F}\ \ln(\frac{P_2}{P_1})$$

$$W = \Delta V \times Q = \Delta V \times 2F \quad \textbf{(8)}$$

In the case of using natural gas infrastructure for the compression and transport of hydrogen, common types of compressors include reciprocating, centrifugal, and to a lesser extent, rotary engines [96]. For compression of hydrogen, reciprocating compressors offer the best efficiency as they only suffer from sealing issues, whereas centrifugal engines require far higher tip speeds and/or rotor circumferences to make up for the lighter hydrogen molecules, and rotary engines suffer from severe leakage issues [97]. These mechanical compression methods are typically considered as adiabatic compression processes when taken as a single compression step [94].

The work to compress hydrogen adiabatically is given by equation (9). The constant k is the ratio of specific heats, which is 1.41 for hydrogen gas.

$$W_{comp,adiabatic} = \frac{kRT_1}{k-1}\left[\left(\frac{P_2}{P_1}\right)^{(k-1)/k} - 1\right] \quad (9)$$

From an ideal, thermodynamic perspective, isothermal compression of hydrogen gas is a less work intensive process, Figure 78 compares the specific work requirement for compression of hydrogen gas for both processes.

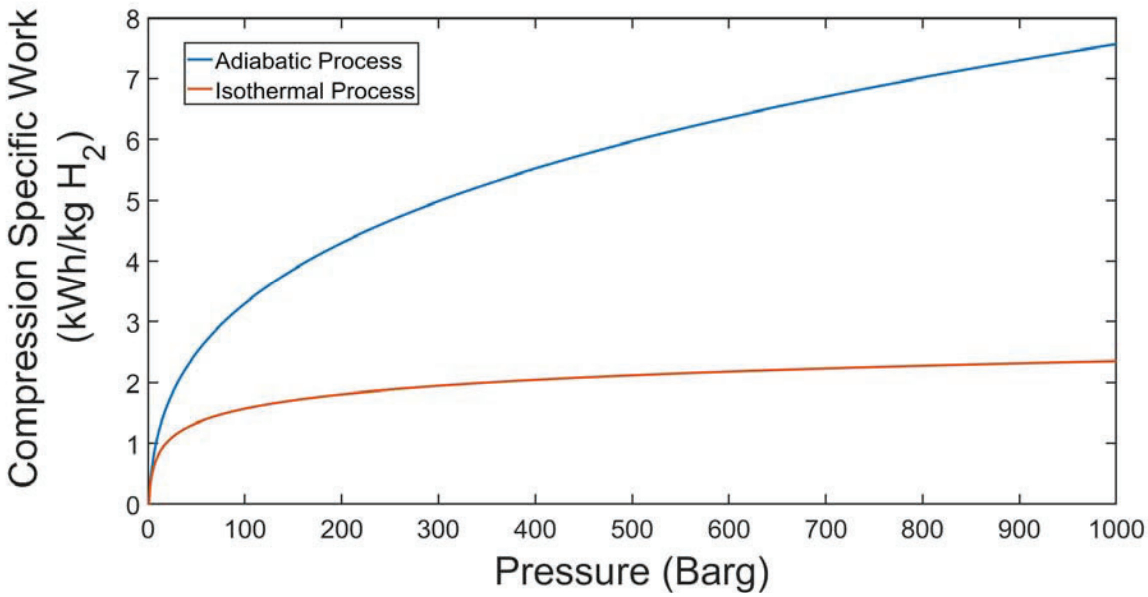


Figure 78. Work requirements for adiabatic vs. isothermal compression of hydrogen gas.

To overcome the limitations of adiabatic compression, mechanical compression processes are often split into stages, with intercooling of the gases in between, bringing the overall process closer to an isothermal compression. Each additional stage adds system complexity and cost considerations however. Furthermore, external mechanical compression suffers from part load efficiency losses and sizing constraints as a result. Further reason to explore the use of electrochemical compression for hydrogen produced through electrolysis.

Electrochemical compression in a PEM electrolyzer stack leads to penalties in the form of both the aforementioned voltage increase, but also in reduced Faradaic efficiencies as a result of product gas losses to cross-over phenomena. Using the developed analytical model, the effective work requirement of electrochemical compression (taking into account both overvoltage penalty and hydrogen losses) can be compared against the ideal case. Figure 79 shows this comparison for the range of 0 to 50 barg, where the departure from ideal compression is limited.

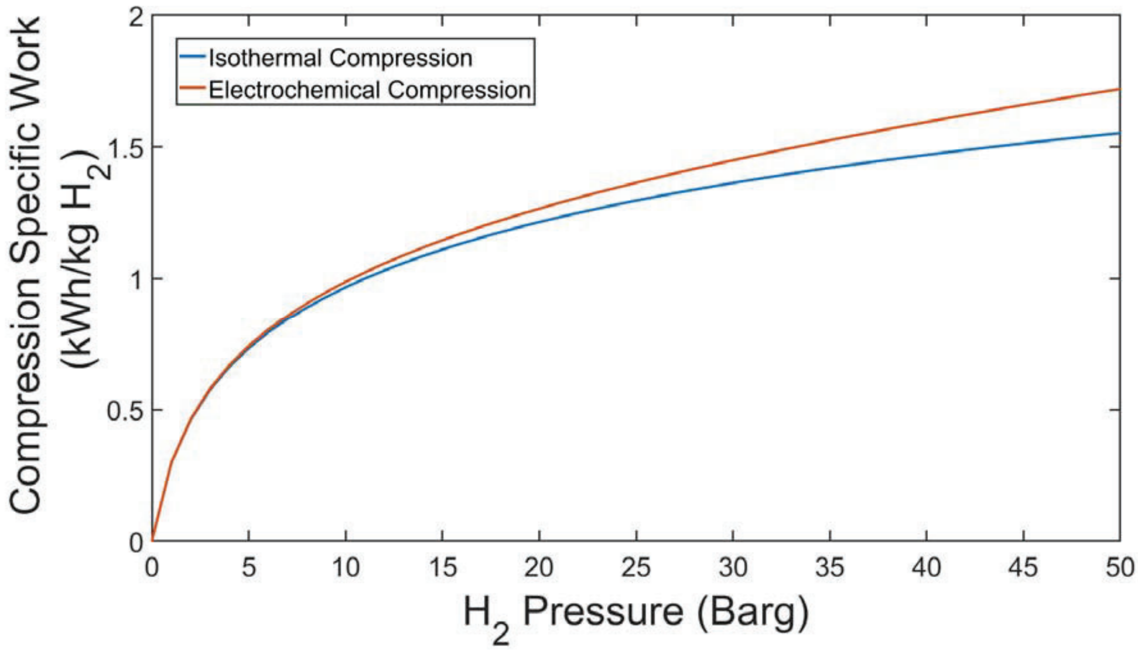


Figure 79. Specific work for electrochemical compression of hydrogen gas in PEM electrolyzer stack versus isothermal compression. (T_{stack} = 55 Celsius, P_{anode} = 0 barg, j = 1 A/cm^2).

The cell overvoltage as a sole function of hydrogen pressure is shown in Figure 80. Included as well is the ANOVA mode of cell voltage as a function of hydrogen pressure (Section 3.2.6.1) for the range of pressures measured. The agreement in cell voltage change attributable to hydrogen pressure observed suggests that the Nernst equation captures the effects of hydrogen pressure, at least for the lower pressures observed. At higher pressures, kinetic improvements could potentially occur, however the kinetics of the hydrogen evolution reaction (HER) at the cathode side are orders of magnitude faster than the oxygen evolution reaction (OER) on the anode side, such that improvements due to elevated hydrogen pressures would largely be negligible. For pressurized electrolysis with equal pressures at the anode and cathode, noticeable kinetic improvements could occur.

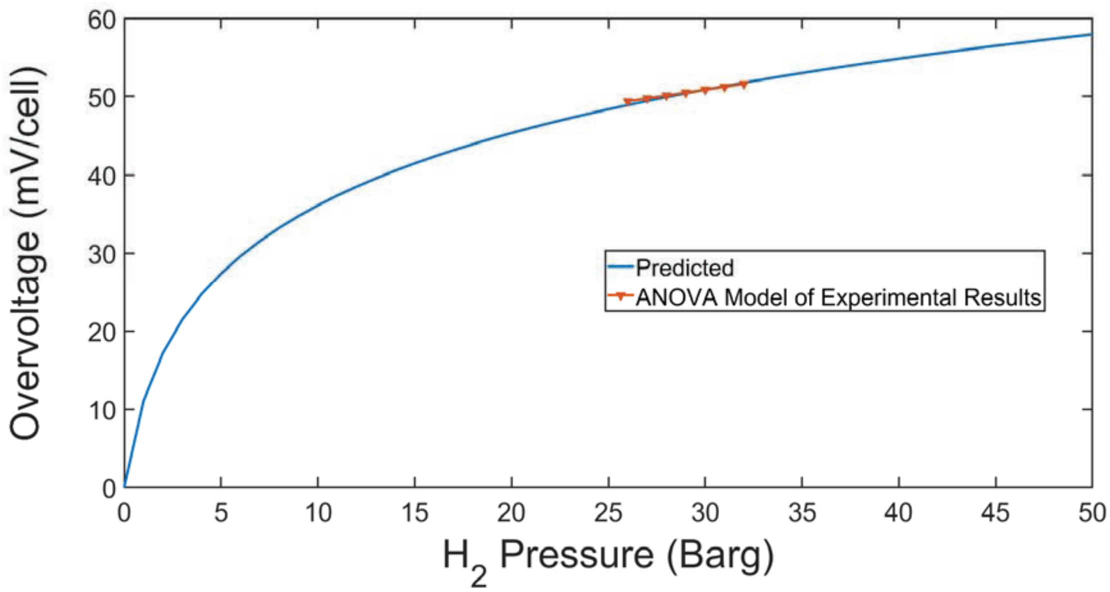


Figure 80. Predicted overvoltage due to increasing hydrogen pressure versus observed average variation using ANOVA on cell voltage measurements.

The extent to which electrochemical compression via electrolysis is effective is limited by gas cross-over losses, which become increasingly prohibitive at lower current densities in the stack. This has implications for the effective part load capabilities of high-pressure PEM electrolysis. The specific energy requirement of hydrogen production across the effective pressure range several load conditions is plotted below (Figure 81). It can be seen that down to 50% load condition, hydrogen pressures of up to 100 barg are within reasonable efficiency ranges, with specific energy requirements of roughly 60 kWh/kg H_2. However, beyond that point it becomes more efficient to operate the stack at increasing current densities to offset the hydrogen losses to cross-over. Operating pressure is also limited by the need to prevent explosive mixtures of hydrogen in oxygen in the anode stream, but this can be prevented by other methods such as the use of gas combiners/catalytic combustors.

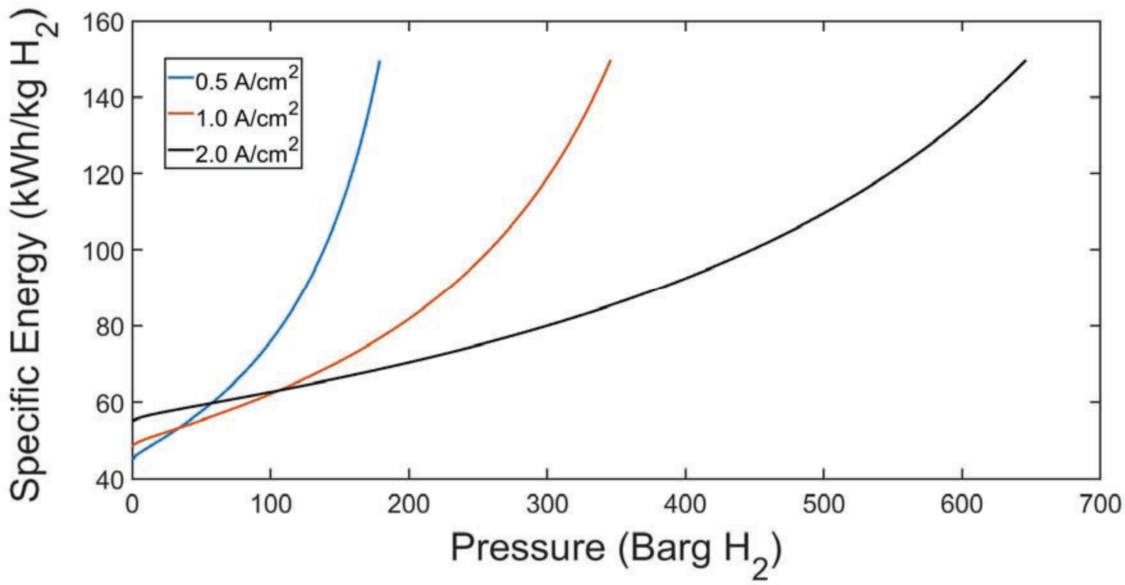


Figure 81. Specific energy of hydrogen production for increasing pressures in the PEM electrolyzer system at several load conditions.

As a result of its similarity to isothermal compression, it is expected that compression during the electrolysis step would be a competitive option due to higher efficiency and reduced system complexity. It is evident however that for very high pressures and/or for electrolyzer systems that are not operating at near full capacities, this form of compression may not be effective.

For the end use case of integration with natural gas pipeline infrastructure or dedicated hydrogen pipeline infrastructure, the US DoE funded the development of an advanced centrifugal hydrogen compressor capable of boosting 350 psig (24 barg) hydrogen gas to >1000 psig (69 barg) at capacities exceeding 100,000 kg H_2/day [98]. A design for a six-stage centrifugal compressor-based system was developed rated at 240,000 kg H_2/day for a discharge pressure of 1285 psig (88 barg) with a total hydrogen efficiency of 98% HHV H_2 [99]. Such a system could be integrated with a large-scale electrolysis plant outputting at 24 barg, boosting the output for pipeline injection to 88 barg. This integration case for the ideal and actual specific compression work of the electrolyzer system is compared against using solely electrochemical compression to output hydrogen at 88 barg in Figure 82 below. It can be seen that even for the actual electrochemical compression case, the compression of hydrogen solely during the electrolysis step is predicted to be more efficient in addition to reducing system complexity by having to size the mass throughput of the compressor system.

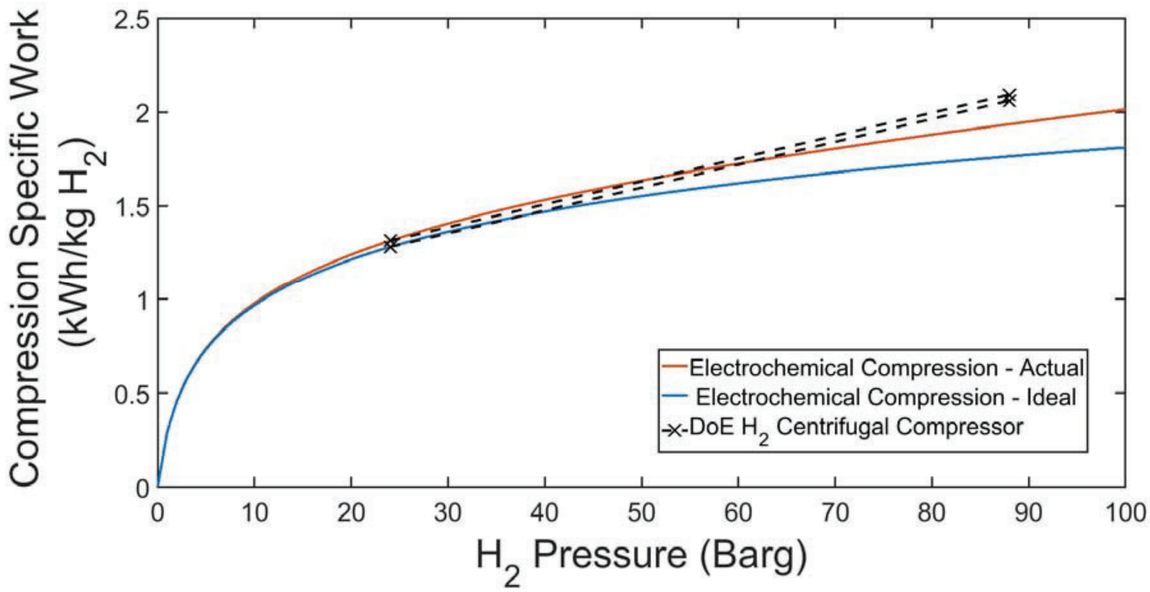


Figure 82. Integration of state-of-the-art H_2 centrifugal compressor design with electrolysis plant for pipeline end-use versus compression solely performed during electrolysis step for ideal and actual electrochemical compression (j = 2 A/cm^2, T_{stack} = 55 Celsius).

For higher pressure hydrogen applications such as vehicle refueling, compression during the electrolysis step is highly ineffective, however external electrochemical compressors show promise in this regime. An external hydrogen electrochemical compressor compresses hydrogen through a PEM electrochemical cell, eliminating safety concerns of mixing hydrogen in oxygen gas. These compressors have been demonstrated performing single-stage compression of hydrogen from ambient pressure to 800 barg [100].

HyET Hydrogen Energy Efficiency Technologies is one such manufacturer of the electrochemical hydrogen compressor technology who have published performance data for optimal conditions for single-step compression of hydrogen from 10 barg to 450 barg [101]. There are still parasitic losses present with respect to back diffusion of hydrogen gas to the low-pressure side, as can be observed with the increasing work requirement with higher hydrogen mass flows (Figure 83).

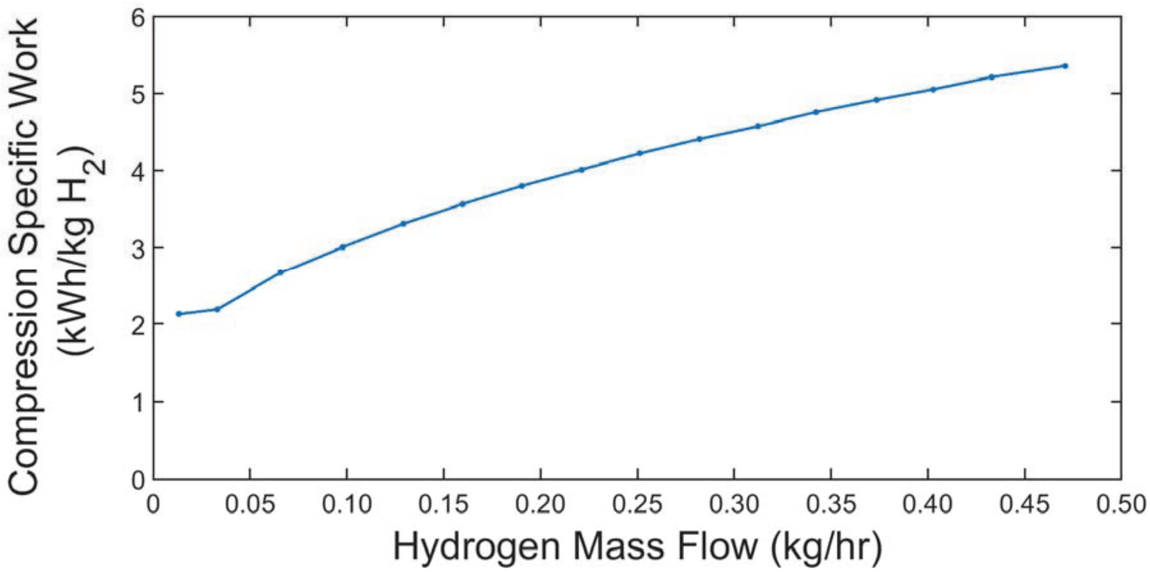


Figure 83. Compression work for HyET electrochemical compressor vs. hydrogen mass flow rate [101].

Taking the scenario of a small hydrogen fueling station at a capacity of 200 kg/day, whose hydrogen supply is maintained on-site by a PEM electrolyzer, the implementation of external electrochemical compression with an electrolyzer system versus compression solely accomplished in an electrolyzer system can be compared. As the available data for the HyET system covers compression from 10 to 450 barg, the station storage pressure will be set to 450 barg. For a fueling station supplying H35 fueling services (350 barg fueling) this is a reasonable final storage pressure [102].

The external electrochemical compressor and electrolyzer systems are scaled up in size by number of electrochemical cells to meet the demand capacity of 200 kg H_2/day (maximum rated flow rate of 8.33 kg H_2/day) at their maximum rated output. Many hydrogen refueling station analyses have employed polytropic expression assumptions in modeling on-site hydrogen compression for refueling [103] [104] [105]. Polytropic compression representative of a typical diaphragm compressor employed at a hydrogen fueling station with a value of n_p = 1.6 and an isentropic efficiency of 80% is also compared against the two cases [55].

The results of this comparison are shown below in Figure 84. Specific energy consumption of hydrogen is strongly dependent on system output for the electrolyzer compression only case due to Faradaic inefficiencies of part-load high pressure electrolyzer operation. The polytropic compression assumption does not likely capture the part load capability of a fixed size diaphragm compressor, however its performance is predicted to be fairly comparable at the full load condition point to the electrolyzer system. The external electrochemical compressors stand out in this application, with specific energy costs of just under 60 kWh/kg H_2.

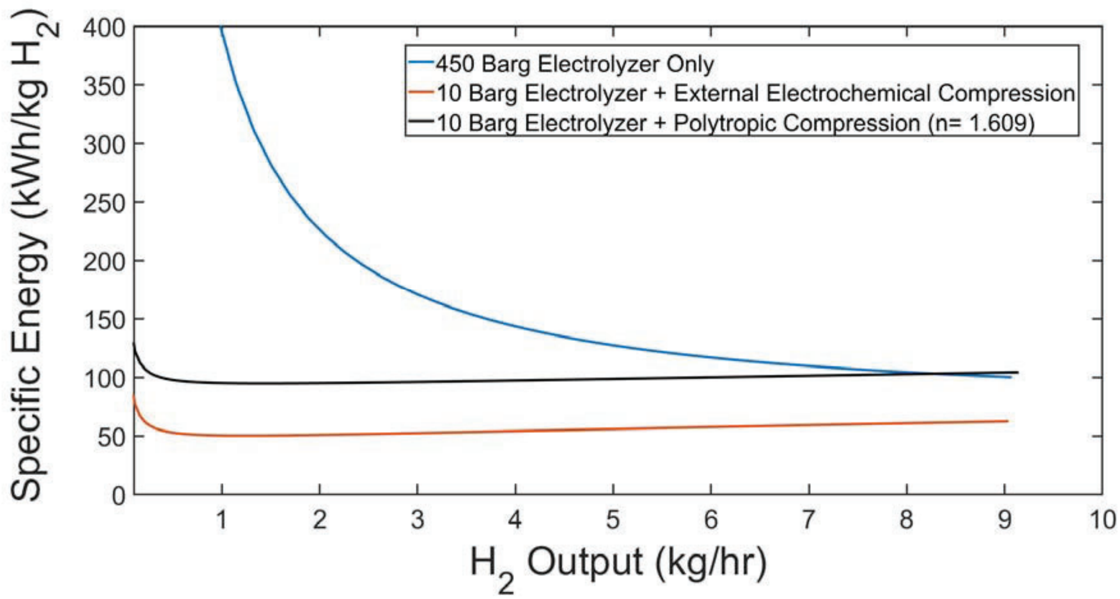


Figure 84. Performance comparison for electrolyzer system with compression in supplying 200 kg/day H_2 at 450 barg intended to be representative of a hydrogen fueling station.

4.5 Summary & Recommendations

Using the data collected from the dynamic operation of the electrolyzer system, several key performance metrics were assessed and parameterized. Electrochemical parameters important for physical models of PEM cells were determined and their dependence on temperature in the case of anodic exchange current density and membrane conductivity was observed. The results matched the limited literature on the subject, which was conducted on systems far smaller than the 60 kW PEM system. Transport parameters for hydrogen gas cross-over in the stack were estimated as well and completed the characterization of the electrochemical compression work requirements.

Using the acquired parameters, a simplified thermodynamic model of the PEM stack that gives accurate species transport as a function of current density, operating temperature and pressure input. Combining the stack model with the relatively flat system losses due to ancillary power consumption and AC/DC power electronics, and with the pressure only dependence of the PSA dryer losses, an accurate system level model emerged for utilization in P2G integration scenarios. The model was exercised to ascertain the suitability of electrochemical compression via PEM electrolysis in pipeline injection scenarios versus state of the art dedicated centrifugal hydrogen compressors (high throughput, medium pressure). It is evident that compression via PEM electrolysis has a number of advantages over even the best external compression methods for pipeline injection. A similar analysis was also carried out in a dedicated hydrogen fueling station application (low throughput, very high pressures) versus external diaphragm and electrochemical compression, wherein compression via PEM electrolysis can be seen to not be well suited to extremely high pressures due to excessive hydrogen cross-over in the stack.

4.5.1 Observations

- Sustained part load operation data at varying operating temperatures and 30 barg cathode pressure was used with trust region optimization methods to determine values for electrolytic membrane conductivity (σ_{mem}), anodic exchange current density($j_{o,an}$), and cathodic exchange current density($j_{o,cath}$). Membrane conductivity was found to vary linearly with operating temperature, for a range of 0.074 S/cm up to 0.087 S/cm from 40 Celsius to 55 Celsius. Anodic exchange current density also showed a strong linear variation with temperature, increasing from 2.92×10^{-7} amp/cm^2 at 40 Celsius up to 1.41×10^{-6} amp/cm^2. Cathodic exchange current density did not show any temperature dependence, and varied very little from the average value of 0.688 A/cm^2.
- Discrepancies between the measured hydrogen output versus the Faradaic hydrogen output, referred to as hydrogen losses, were characterized as a result of three mechanisms; losses to dissolved hydrogen gas in cathodic water, losses to the PSA dryer regeneration process, and losses to gas cross-over in the electrolysis stack.
- Losses to dissolved hydrogen gas in cathode water were determined to be orders of magnitude lower than what was observed based upon Henry's Law estimations.
- Hydrogen losses to the PSA dryer were characterized using the rated orifice output at nominal conditions in combination with orifice flow relations and measurements of inlet pressure and valve condition at the dryer orifice over time, using only sustained periods of time where inlet pressure was constant. At nominal conditions, the dryer losses were rated at 0.744 kg/hr H_2, explaining the majority of hydrogen loss in the operation of the electrolyzer. Low part load operation where the system pressure became less stable due to

erratic stack current throughput led to increasing hydrogen losses that were attributed to unsteady orifice flow conditions.

- Elimination of the PSA potentially affords an increase in effective minimum part load (from 22.5% rated system power down to 10% rated system power), and stable performance (close to rated efficiency) down to 20% rated system power rather than 50%. For many applications of hydrogen, high purity (dry) hydrogen is desired, but a no PSA dryer configuration could be an option for pipeline injection of hydrogen, particularly for low concentration injection (<17% by volume H_2 in natural gas @ 20 Celsius, 30 Barg).
- A top-down estimate of hydrogen losses to gas cross-over was used for the remaining discrepancy, providing an overestimation of hydrogen losses to that particular mechanism. Due to the regular pressure testing of the hydrogen process piping, the assumption that minimal hydrogen loss went to leakage rather than gas cross-over was justified. Cross-over parameters for hydrogen gas were fit against this experimental data using linear regression, giving a diffusive permeability value of $\varepsilon_{H2}=1.76\times10^{-10}\left[\frac{\text{mol}\cdot\text{sec}}{\text{cm}\cdot\text{bar}}\right]$ and a partial pressure enhancement factor of $A_{H2}\approx0\ \left[\frac{\text{bar cm}^2}{\text{amp}}\right]$.
- A bottom-up estimate of hydrogen losses using combustible gas concentration sensing in the anode outlet was carried out and compared against the top-down estimate. The two estimates differed by nearly two orders of magnitude. As the bottom-up estimate relied on the assumption that there was no catalytic combustion of hydrogen in oxygen on the anode outlet, it was determined that the top-down estimate provided a result closer to reality. Fitted transport parameters for hydrogen cross-over from the bottom-up estimate were $\varepsilon_{H2}=4.47\times10^{-13}\left[\frac{\text{mol}\cdot\text{sec}}{\text{cm}\cdot\text{bar}}\right]$ and $A_{H2}\approx154.34\ \left[\frac{\text{bar cm}^2}{\text{amp}}\right]$.
- The semi-empirical stack model with fitted electrochemical and transport parameters was combined with relationships for hydrogen dryer orifice loss and AC/DC power electronics losses and exercised against the VRES load following cases using only the stack current, temperature, and pressure set points as inputs. Power consumption of the system and stack were accurately modeled, as was hydrogen output for load conditions where orifice losses to the dryer were accurate ($j > 0.7$ amps/cm^2). For an electrolyzer system utilizing current control rather than mass flow control (the more realistic scenario moving forward), this would not be expected to be an issue.

- The analytical model was used to characterize the electrolysis based electrochemical compression of hydrogen gas. The actual compression losses matched very closely with isothermal compression, only requiring ~0.1 $kWh_{el}/kg\ H_2$ more than isothermal compression at of hydrogen from 0 barg to 30 barg (a 7% increase).
- The modeled increase in electrical work due to increasing hydrogen pressure was compared against ANOVA predicted variation from the electrolyzer operating conditions study and showed good agreement.
- The performance of the electrolysis based electrochemical compression was compared against the performance of a state-of-the-art centrifugal hydrogen compressor design specs for hydrogen pipeline integration. Electrochemical compression during the electrolysis step showed favorable performance aspects over an integration of first stage compression in the electrolysis step followed by second stage compression in the centrifugal compressor.
- The performance of the electrolysis based electrochemical compression was assessed for the high-pressure end-use application of hydrogen refueling (450 barg H_2). It was shown that this application is ill-suited to the current projected capabilities of electrolysis based electrochemical compression. Performance data from external electrochemical compression systems did show attractive performance characteristics for the integration of external electrochemical compression with first stage electrolysis based electrochemical compression, over the integration of electrolysis-based compression with a general polytropic compression model (selected from hydrogen refueling station literature), and the compression of hydrogen solely in the electrolyzer.

4.5.2 Recommendations

This study utilized the data obtained from dynamic load following testing with the PEM system to carry out further analysis regarding PEM electrolyzer characteristics and to develop analytical tools for their integration in P2G studies. As a result of these extended analyses, the following recommendations are made.

- More focused studies are needed on in-situ gas cross-over in PEM electrolyzer stacks, particularly in pressurized electrolysis. Special attention should be paid to ensure combustible mixtures of hydrogen gas in the anode are avoided.

- Consideration of effective part load range for pressurized PEM electrolysis is needed for use of such systems in power-to-gas for flexible load following applications.
- For pipeline integration, high pressure electrolyzers alone can effectively produce and pressurize hydrogen to desired levels rather than increasing system complexity by addition of external compression systems.
- Research and development on high pressure electrolysis (400+ barg H_2) could result in highly effective and simple systems for production and utilization of power-to-gas pathways for fueling applications, current capabilities of high-pressure electrolysis are not effective for pressures past 100 barg.

5 Blending of hydrogen gas into pipeline natural gas

Natural gas is a mixture of several lighter hydrocarbons, primarily methane, though appreciable amounts of ethane, propane, and butane are often present. In addition to the hydrocarbons, there are also highly variable amounts of impurities in the form of nitrogen, carbon dioxide, and sometimes trace amounts of hydrogen. A mass spectroscopy analysis of natural gas at the Engineering Lab Facility (ELF) at UC Irvine gave the following mol composition (Table 14).

Table 14. Mol fraction of natural gas constituents for Engineering Laboratory Facility – 1993.

% Mol Fraction			
Methane	95.800	**Hexane**	0.017
Ethane	1.400	**Heptane**	0.017
Propane	0.400	**Octane**	0.016
iso-Butane	0.050	**Carbon Dioxide**	1.900
n-Butane	0.050	**Oxygen**	0.000
iso-Pentane	0.025	**Nitrogen**	0.300

When gaseous fuels are interchanged in a combustion process, certain burner parameters may need to be adjusted to maintain the energy throughput, stability, and any secondary characteristics such as the temperature distribution of the combustion chamber which can influence emissions.

To maintain heat rate, the volumetric heat rate may need to be adjusted to compensate for differences in the heating value of the fuel. The Wobbe Index is a commonly used indicator for the interchangeability of fuel gases on the basis of energy throughput. By taking the Bernoulli equation (*11*) for describing a steady-state, inviscid, incompressible and laminar flow condition from one point in a horizontal flow path to another, and combining with our heat rate expression (10), we can obtain the expression for the Wobbe index - equation (*12*).

$$\dot{q} = \dot{V} * HHV_{vol} \tag{10}$$

$$P_1 + \frac{\rho \dot{V}_1^2}{2} = P_2 + \frac{\rho \dot{V}_2^2}{2} \tag{11}$$

$$WI = \frac{HHV_{vol}}{\sqrt{SG}} \tag{12}$$

Appreciable differences in Wobbe Index for a fuel intended to substitute the design specification fuel indicate that the combustor should be modified to maintain energy throughput at the fuel nozzle. This does not account for other combustion characteristics that are heavily influenced by the fuel gas such as stability (flashback and blow-off), flame length, temperature, and emissions that could also require modification of the combustor when substituting fuel gases. Wobbe Index then, accounts for the ability of a fuel gas to offer equivalent energy throughput in the same piping system. Natural gas and hydrogen differ appreciably in density and heat content from one another. Table 15 below summarizes the characteristics of hydrogen and natural gas used throughout this study. Natural gas characteristics are based on the mass spectroscopy analysis from Table 14 above. Hydrogen gas is nearly one tenth the weight of natural gas on average. From a gravimetric standpoint, hydrogen is roughly three times as energy dense, however from a volumetric standpoint, hydrogen has less than a third of the energy density of natural gas. From a Wobbe Index standpoint, the interchangeability of natural gas and hydrogen gas start to appear favorable. Although hydrogen gas delivers less energy per unit volume, it also has a much lower specific gravity, allowing a greater amount of hydrogen to flow through the same orifice. The result is a Wobbe Index that is within 10% of natural gas.

Table 15. Hydrogen and Natural Gas Characteristics (1 atm, 20 Celsius)

	Hydrogen [106]	**Natural Gas**
Density (kg/m^3)	0.083	0.707
Specific Gravity	0.070	0.588
LHV_{mass} (MJ/kg)	119.960	48.262
LHV_{vol} (MJ/m^3)	10.048	34.025
HHV_{mass} (MJ/kg)	141.800	53.552
HHV_{vol} (MJ/m^3)	11.877	37.754
Wobbe Index (MJ/m^3)	45.049	49.235

As hydrogen gas is blended in with natural gas, the volumetric heat content drops dramatically due to the large difference between the two. By itself, natural gas can vary in heating content an appreciable amount. In the case of southern California service territory, this can be observed in a recent LNG interchangeability study carried out by San Diego Gas & Electric (SDG&E) and SoCalGas. The study involved gas chromatograph measurements of pipeline gas at a number of locations across their service territory. The extremity of these measurements for the pipeline gas varied as much as 6.3 MJ/m^3 above the national average **[107]** to 1.1 MJ/m^3 below for an observed variation of 7.5 MJ/m^3 (higher heating value basis) **[108]**.

When it comes to the addition of hydrogen gas to natural gas, the closest analogue in California to specifications on fuel gas characteristics for injection to natural gas infrastructure is SoCalGas's Rule No. 30 on transportation of customer-owned gas **[109]**. Rule 30 is intended to regulate the quality of customer owned gas injection to SoCalGas pipelines and includes minimum and maximum limits on both higher heating value as well as Wobbe Index. Taking the national average for higher heating value and Wobbe Index for natural gas as the baseline, the variation in heating value and Wobbe Index with the addition of hydrogen can be observed and compared to the limits imposed by Rule 30 as well as to the observed variation in natural gas quality. Figure 85 shows this variation for higher heating value and Wobbe Index.

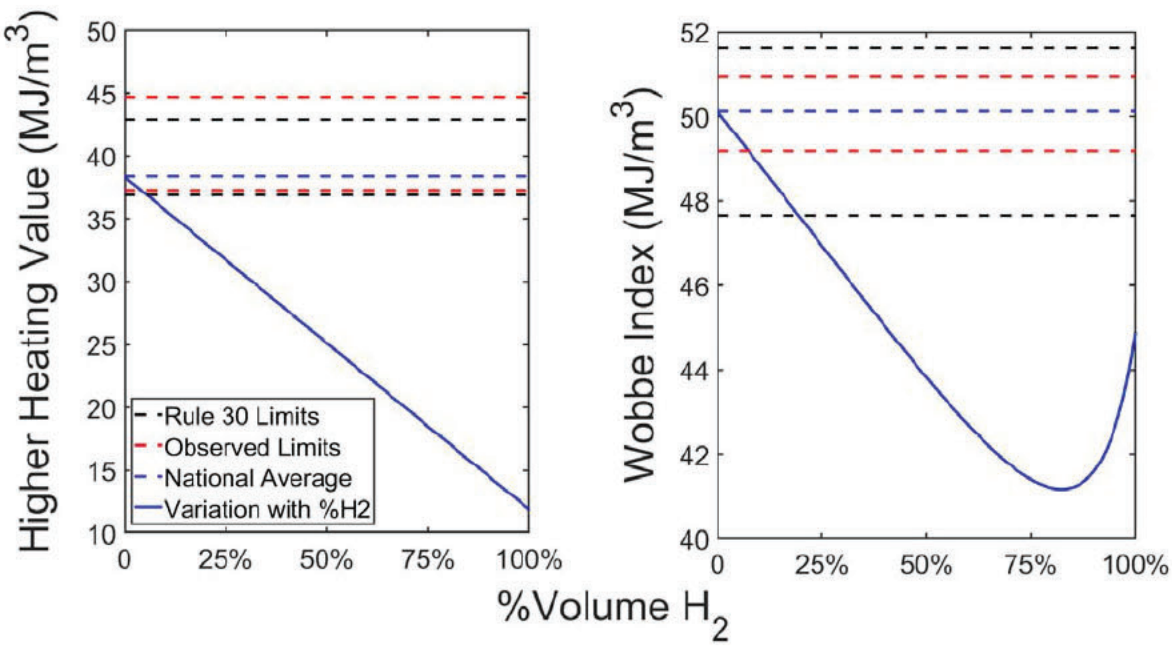


Figure 85. National average for higher heating value and Wobbe Index of natural gas balanced volumetrically with increasing amounts of hydrogen versus the observed limits of natural gas variation and rule 30 limits.

It is readily apparent that the extent to which hydrogen can be blended with natural gas will be highly depend on the initial quality of the natural gas. This idea has also been found to apply to other fuel gas interchangeability parameters such as burning velocity, flashback propensity, and yellow tipping [110]. Using the Rule 30 limits as representative limits for the addition of hydrogen, just under 5% by volume H_2 can be blended into natural gas, limited by higher heating value restrictions. On a Wobbe Index basis, this limitation is much closer to 20% by volume. There is an appreciable difference in the allowable amount of hydrogen gas that can be injected depending on the initial quality of gas. Table 16 summarizes the different allowable ranges of hydrogen gas by volume, on the same Rule 30 basis, for the two 'extremes' of observed natural gas quality.

Table 16. Allowable percentage of hydrogen by volume in natural gas for complying with Rule 30 standards on higher heating value and Wobbe Index

Natural Gas	Higher Heating Value	Wobbe Index
Max. Observed	23%	27%
National Average	5%	19%

Min. Observed	1%	13%

Ultimately, separate standards will need to be set for the addition of hydrogen to natural gas infrastructure based on careful study of its effects across the broad spectrum of natural gas end uses. Heating value and Wobbe Index alone do very little to capture the entirety of a fuel gases behavior for any given combustor. Still, Rule 30 can serve as a representative regulation for future regulation concerning hydrogen addition. In the case of this study, it serves to highlight the extent to which natural gas quality alone varies relative to quality requirements for third party injection of fuel gas to the pipeline.

5.1 Long-term Injection of Hydrogen produced by Electrolyzer System

The University of California Irvine's (UCI) P2G demonstration consists of a Proton OnSite 'C10' 60kW Proton Exchange Membrane electrolyzer located at the UCI Central Plant (UCICP). The UCICP is a combined heat and power (CHP) power plant utilizing a NGCC system comprised of a 13.8 MW Solar Turbines Titan 130 natural gas fired turbine and a 5.6 MW Dresser-Rand Murray Steam Turbine for the topping cycle. A heat recovery steam generator on the gas turbine exhaust recovers heat for operation of the steam turbine, a steam-driven chiller, or for storage in a thermal energy storage (TES) system. The UCICP also incorporates several electrically driven chillers and natural gas boilers for system flexibility in meeting campus heat demand and modulating the gas turbine's electrical load.

The gas turbine at the UCICP utilizes catalytic reduction to minimize emissions of CO and NOx. CO emissions are controlled by oxidation catalyst, and NOx emissions are controlled through Solar Turbines SoLoNOx™ combustion system which is a combination of lean pre-mixed combustion and selective catalytic reduction (SCR) by way of ammonia injection. Emissions requirements in the southern California area are set and enforced by the South Coast Air Quality Management District (SCAQMD) and are issued on an individual plant basis based on best available control technology (BACT), which for most NGCCs are currently in the range of 2 ppm for both NOx and CO on a 15% O_2 basis, 1-hour average [111]. Due to these relatively stringent emissions requirements, the performance of the emissions control systems is critical, and any impact in emissions due to hydrogen addition, no matter how slight, could impact emissions compliance significantly.

The C10 electrolyzer system outputs hydrogen at a maximum flow rate of 0.92 kg/hr at pressures up to 33.5 Barg. The C10 electrolyzer system load followed various load profiles including on-site solar PV and nearby wind farm load profiles, and as such the hydrogen injection rate to the natural gas line varied. The gas turbine burns anywhere from 2000 to 3200 kg/hr of natural gas for its typical range of operation. The highest observed concentration of hydrogen in the fuel feed to the gas turbine was 0.5% for this phase of testing on a volumetric basis. Over 4000 hours of hydrogen injection has been accomplished to date with the electrolyzer system.

To increase the range of hydrogen concentration in the natural gas line, a temporary high-throughput test system was designed that aimed for achieving 4% by volume hydrogen. This test was carried out in one day, preceding a planned turbine shutdown for the UCICP so as to avoid any downtime in the event of turbine shutdown due to the greater hydrogen throughput. As the hydrogen injection rate was limited by the current electrolyzer system's capacity, hydrogen cylinders were brought in and manifolded together in conjunction with pressure regulation and mass flow control to achieve a maximum throughput of just over 9 kg/hr H_2. Figure 86 summarizes the process flow of the two tests.

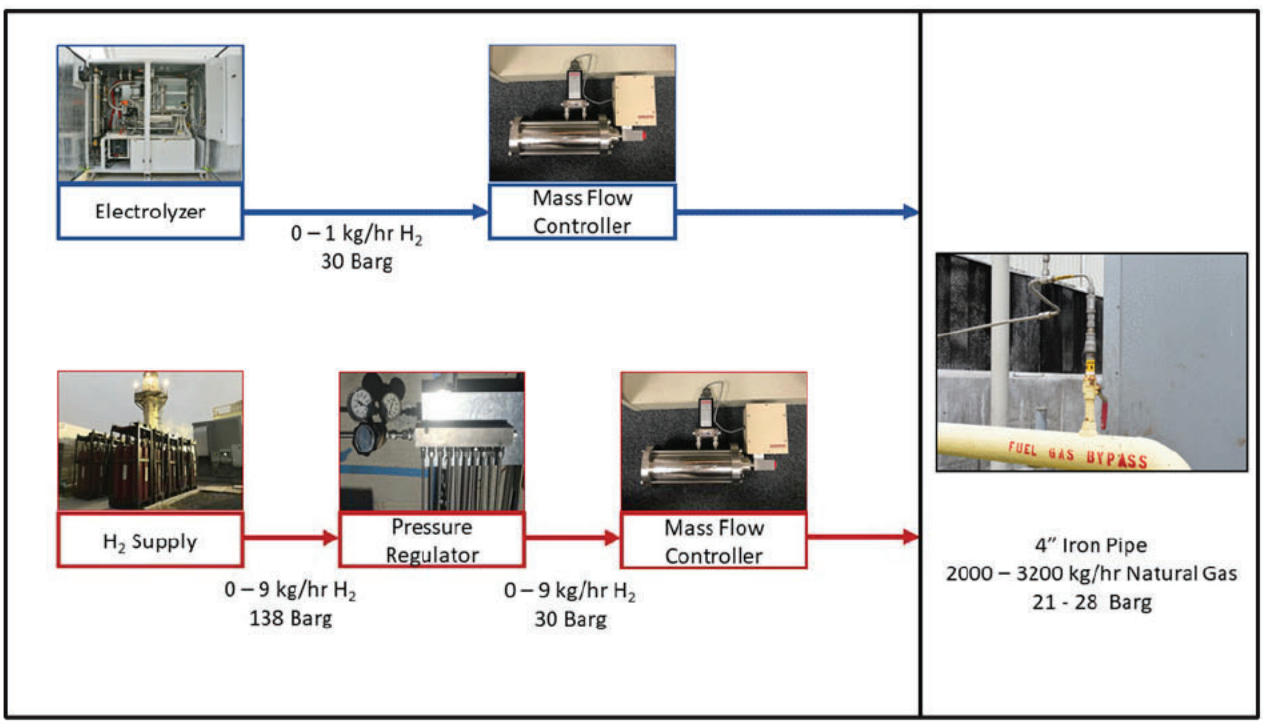


Figure 86. Simplified process flow diagram for electrolyzer based injection of hydrogen and one-time high throughput hydrogen cylinder sourced hydrogen injection.

Clean energy monitoring system (CEMS) data was made available by the UCICP personnel for the duration of injection testing, which provides the following metrics on a 1-minute resolution; gravimetric fuel gas flow(klb/hr), total stack flow (kcf/hr), CO and NOx emissions (ppm, ppm @ 15 % O2, g/hr), turbine load (MW_{el}) and the temperature of the SCR system (Celsius). In addition to the CEMs data, hydrogen mass flow rate, hydrogen pressure, and natural gas line pressure were recorded. Analysis of Variance (ANOVA) was used to analyze data from both the long term, electrolyzer hydrogen injection tests and the one-time high throughput hydrogen injection test.

5.1.1 Results

Throughout all phases of testing, hydrogen produced by the electrolyzer system was injected downstream into a natural gas pipeline at an injection point within the UCI Central Plant (Figure 10). As the injection point is upstream of the combustion turbine, the entirety of this hydrogen gas is assumed to have been combusted in the turbine. UCI Central Plant personnel provided operational data for the combustion turbine from August 2016 to March of 2018, capturing all turbine operation during hydrogen injection, as well as data between injection for comparison.

At a maximum rate output of 0.91 kg/hr H_2, the magnitude of hydrogen flow from the electrolyzer system relative to the total fuel gas flow to the combustion turbine is several orders of magnitude smaller. Figure 87 below shows the expected range of observed percentage hydrogen gas by volume in the natural gas line as a result of electrolyzer output and turbine load conditions. The maximum expected percentage by volume of hydrogen that the electrolyzer system can achieve in natural gas ranges from 0.33% to 0.50%.

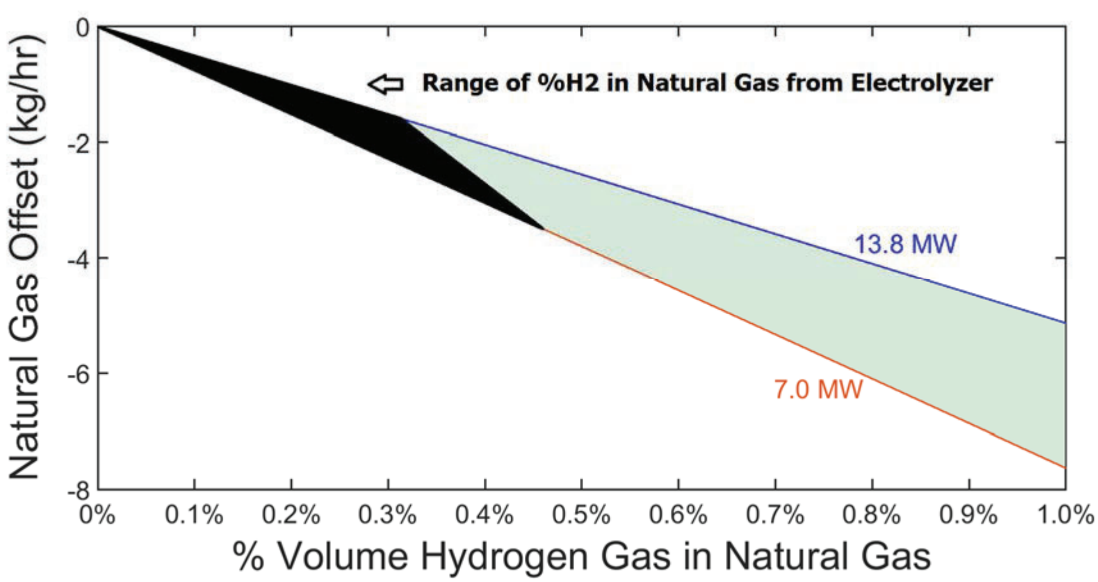


Figure 87. Expected natural gas flow offset with addition of hydrogen gas to the gas turbine fuel input.

Data collected from the turbine was time averaged from 1-minute intervals to hourly intervals and matched with hydrogen flow to the injection point. Effects of interest on turbine operation due to hydrogen addition is its influence on emissions. Emissions of carbon dioxide can be inferred from measured total fuel gas flow to the combustion turbine. Emissions of the criteria pollutants carbon monoxide and NO_x are monitored as well. Criteria pollutant emissions are only measured downstream of their respective catalytic clean-up processes, and as such, the 'raw' emissions from the combustion process are not available and the direct effect of hydrogen addition on these emissions is not observable. Due to the prevalence of these downstream emissions clean-up measures, it is still of great interest whether or not hydrogen influences the end emissions result. Despite the large population of data, there was an imbalance that influenced statistical analysis via ANOVA. No hydrogen injection was carried out on turbine set points below 9.3 MW_{el}, but data was collected on electrical set points as low as 7.0 MW_{el} with no hydrogen injection. As a result, the population that is considered below was orthogonalized to get rid of that particular imbalance. Figure 88 below shows the two populations of turbine data.

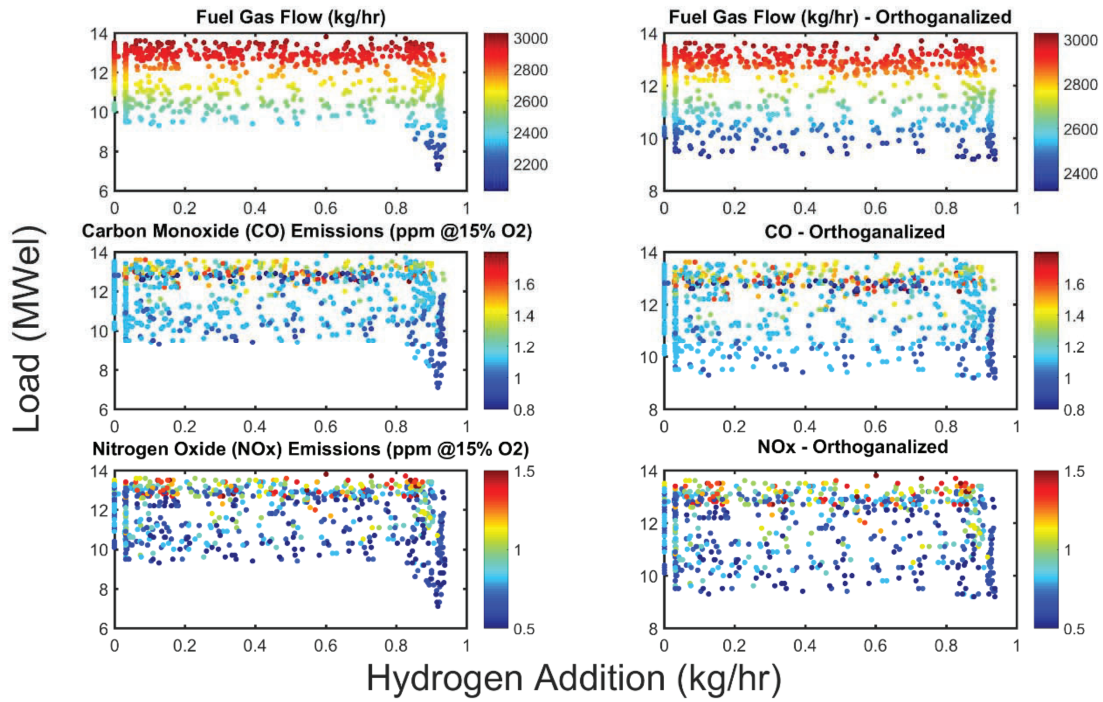


Figure 88. Population of turbine operation data versus hydrogen addition via injection from electrolyzer system throughout test period, all points (left) and orthogonalized input used for ANOVA (right).

The observed correlations of hydrogen addition (kg/hr) and turbine load (MW_{el}) with the three responses of interest (Total Fuel Gas Flow (kg), NOx (ppm @ 15% O_2), and CO (ppm @15% O2)) are displayed in Figure 89. In all cases, turbine load is overwhelmingly more influential as a predictor, not surprising given the marginal amount of hydrogen addition. The slight negative correlation of hydrogen addition associated with all responses is interesting, but too small to be of significant meaning except potentially in the case of total gas flow.

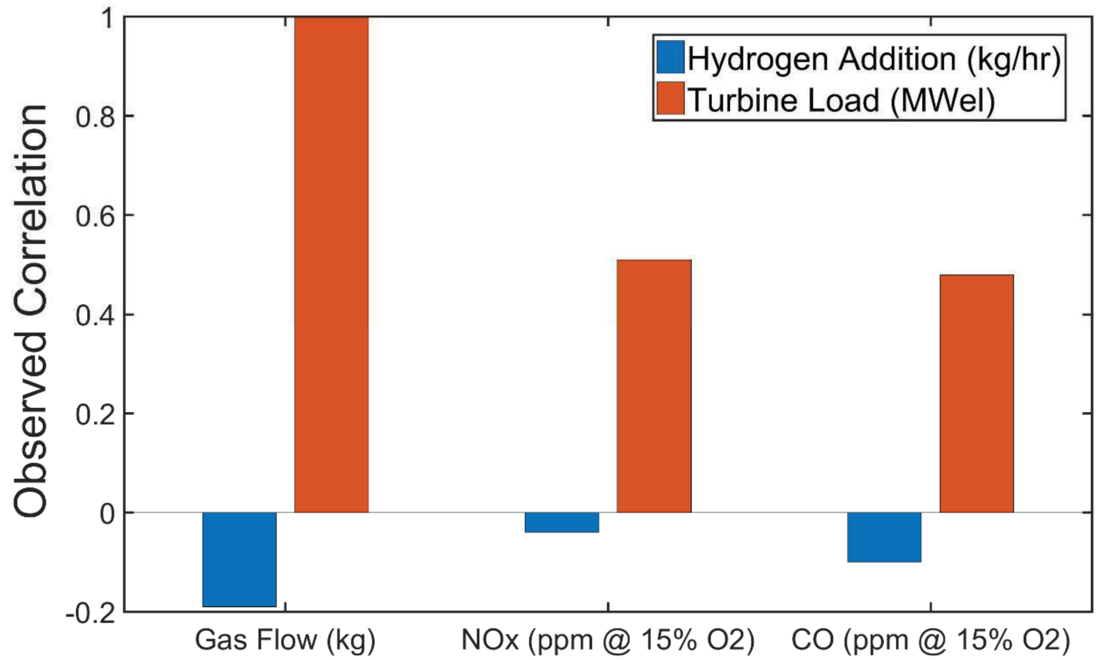


Figure 89. Observed correlation for turbine injection of hydrogen from electrolyzer system and turbine load against total fuel gas flow, NOx, and CO emissions using ANOVA analysis.

5.1.2 Effects of Hydrogen Addition on Gravimetric Gas Flow to Turbine

The results of the ANOVA analysis for total gas flow are summarized below in Table 17. The correlation of load versus gas flow is several orders of magnitude higher than hydrogen addition. Furthermore, the f-value of the hydrogen addition factor is so low relative to electrical load, and even relative to the SCR temperature factor, that the observed trend due to hydrogen addition (Figure 90) is highly uncertain.

Table 17. Summary of ANOVA analysis of the effects of hydrogen injection from the electrolyzer system, turbine electrical load, and SCR temperature on emissions of carbon monoxide post catalytic reduction from the combustion turbine.

	Sum of Squares	Degrees of Freedom	Mean Square	F Value	P-value (Prob > F)
A-H2	0.0000	1	0.0000	1.2678	0.2605
B-Load	4.5866	1	4.5866	142573.5349	<0.0001
C-SCR Temp	0.0121	1	0.0121	376.7809	<0.0001
Model	5.6285	3	1.8762	58319.2711	< 0.0001

Std. Dev.	187.943	**R-Squared**	0.9956
Mean	2735.136	**Adj R-Squared**	0.9956

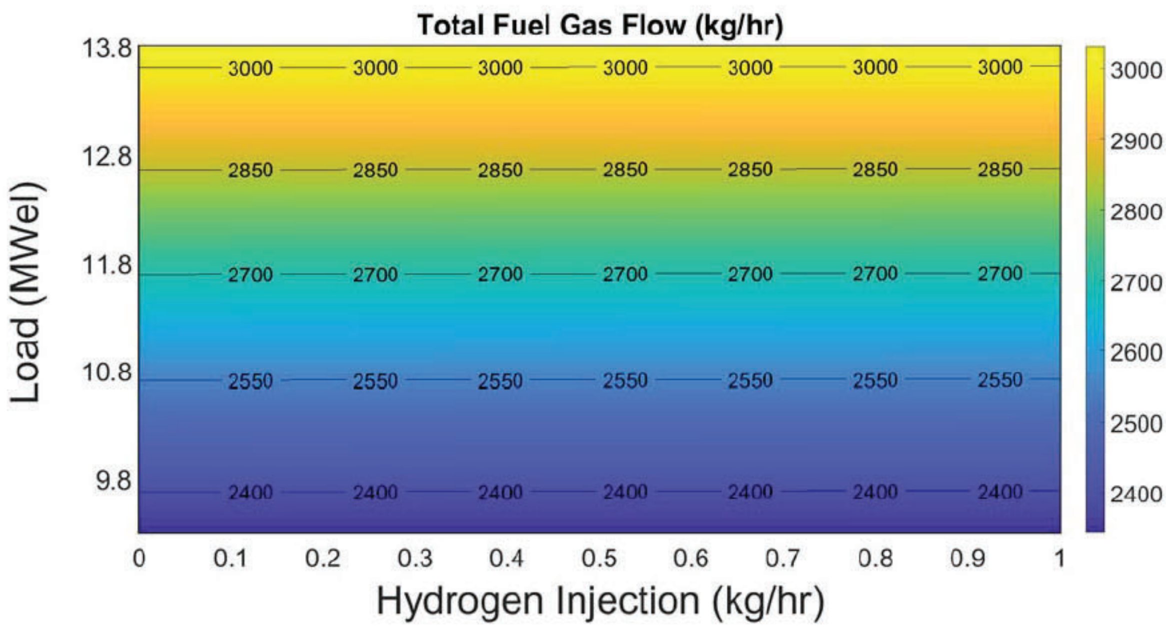


Figure 90. Contour plot of ANOVA predictive model for combined influence of turbine load and hydrogen injection on total fuel gas flow.

The predicted trend from the statistical model matches well with the expected variation in total fuel gas flow within the range measured (Figure 91). The average in natural gas offset predicted from the ANOVA analysis per kg of hydrogen addition is 2.50 kg, however the 95% confidence intervals are relatively wide, with a lower range of 0.75 kg of natural gas offset per kg of hydrogen, and an upper range of 4.25 kg.

Extending the model outwards, the ANOVA prediction matches the prediction from the fixed heat rate prediction reasonably well (Figure 92). This suggests that at least for the lower ranges of hydrogen mixtures we are considering here in this study, for the predicted impact on fuel gas flow and by extension the reduction in carbon dioxide emissions due to hydrogen blending in natural gas, we can use a fixed heat rate calculation to predict the average effect of hydrogen addition. ANOVA analysis as a statistical tool only predicts significant means within the population and is not reliable for precise calculations. In this case, due to the low correlation, there is a large variation in gas flow for a given electrical load that is not accurately explained by the predicted effects of hydrogen injection, and more likely due to uncontrollable factors (of which there are many in the case of the combustion turbine).

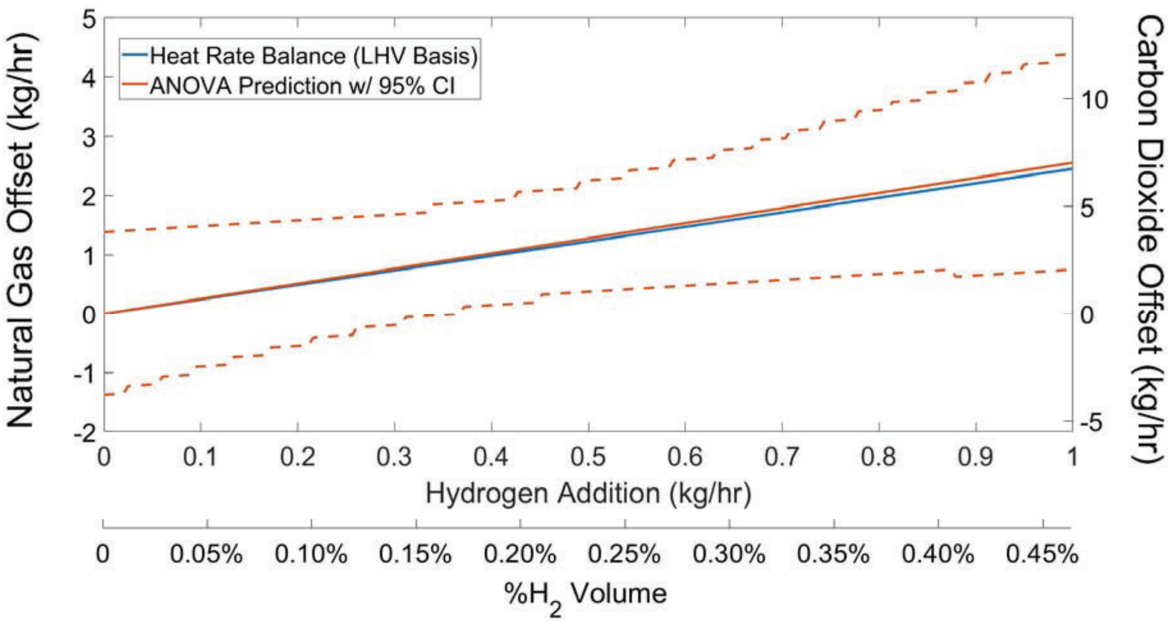


Figure 91. ANOVA predicted model with 95% confidence interval versus fixed heat rate prediction for offset of natural gas flow with the addition of hydrogen within range of testing (Turbine Load = 11.8 MW_{el}).

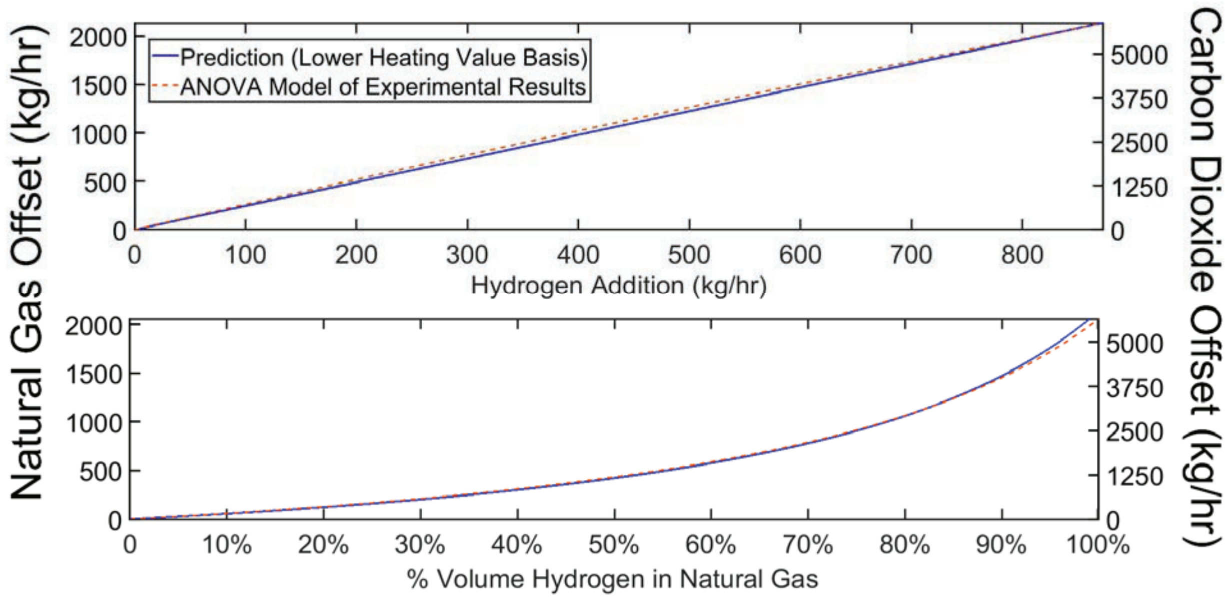


Figure 92. ANOVA predicted model versus fixed heat rate prediction for offset of natural gas flow with the addition of hydrogen up to 100% hydrogen (Turbine Load = 11.8 MW_{el}).

5.1.3 Effects of Hydrogen Addition on Carbon Monoxide (CO) Emissions

In the case of the criteria pollutant emissions, the accuracy of the ANOVA prediction approved appreciably with the inclusion of the selective catalytic reduction system (SCR) temperature. The ANOVA results are summarized below in Table 18. The amount of hydrogen being injected did not have anywhere near as much influence as load and SCR temperature. The trend predicted by the ANOVA model for the addition of hydrogen is shown below in Figure 93. The range of carbon monoxide emissions (from 1 ppm to 1.4 ppm) is so limited that it is difficult to draw any real conclusions, when compounded with the limited range of hydrogen addition, as to the effects of hydrogen addition on such emissions.

Table 18. Summary of ANOVA analysis of the effects of hydrogen injection from the electrolyzer system, turbine electrical load, and SCR temperature on emissions of carbon monoxide post catalytic reduction from the combustion turbine.

	Sum of Squares	Degrees of Freedom	Mean Square	F Value	P-value (Prob >F)
A - H_2 (kg/hr)	0.0110	1.0000	0.0110	1.8491	0.1743
B - Load (MWel)	2.3612	1.0000	2.3612	398.6190	< 0.0001
C - SCR Temp (Celsius)	4.2247	1.0000	4.2247	713.2296	< 0.0001
AB	0.0257	1.0000	0.0257	4.3341	0.0377
AC	0.0387	1.0000	0.0387	6.5324	0.0108
BC	1.9609	1.0000	1.9609	331.0528	< 0.0001
A^2	0.0912	1.0000	0.0912	15.4011	0.0001
B^2	0.0492	1.0000	0.0492	8.3045	0.0041
C^2	5.8618	1.0000	5.8618	989.6097	< 0.0001
Model	10.0496	9.0000	1.1166	188.5114	< 0.0001

Std. Dev.	0.0770	R-Squared	0.6815
Mean	0.8899	Adj R-Squared	0.6779

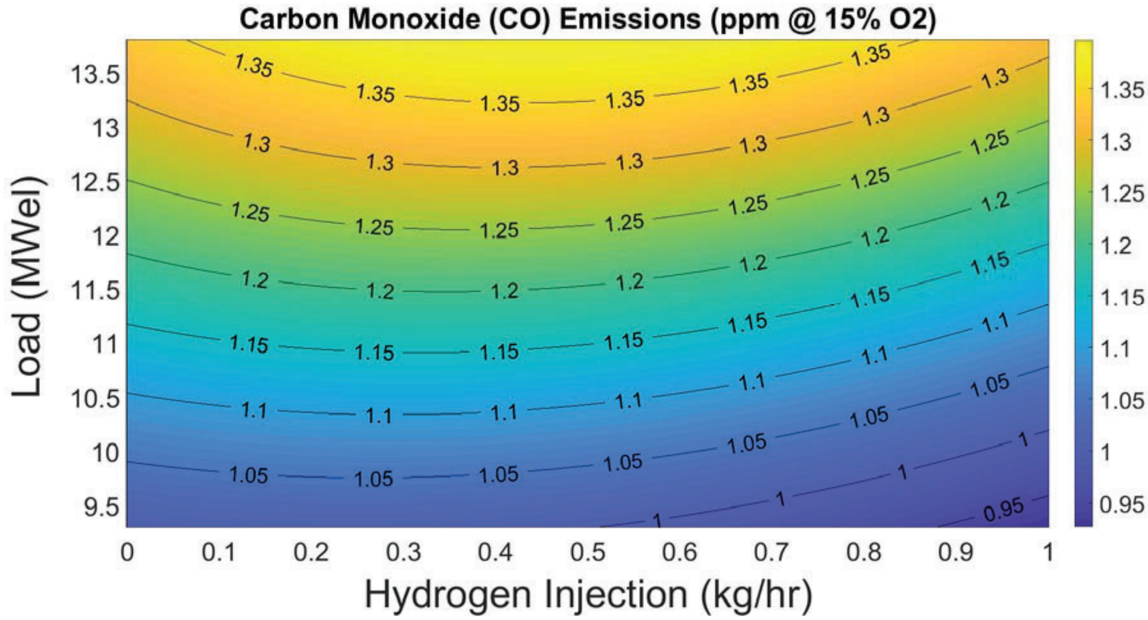


Figure 93. Contour plot of ANOVA predictive model for combined influence of turbine load and hydrogen injection on carbon monoxide emissions (SCR Temperature = 592 Celsius).

5.1.4 Effects of Hydrogen Addition on Emissions of Nitrogen Oxides (NO_x)

Table 19 summarizes the results of the ANOVA analysis on NO_x emissions. Given the low f-value and poor correlation, observed variation in NO_x emissions that is attributed to hydrogen addition is more likely due to other, uncontrollable factors.

The predicted trend for NO_x emissions as a function of hydrogen injection across load conditions is plotted in Figure 94. High loads correlated to higher NO_x concentrations is an expected result that matches up with similar studies on gas turbine emissions, as is the trend of increasing NO_x emissions with the addition of hydrogen observed at lower loads. However, at the higher load conditions, a downtrend in emissions is observed. This runs counter to observations made on unmodified natural gas fired turbines of similar scale when hydrogen was introduced, although the studies on these situations are limited [112] [113].

Table 19. Summary of ANOVA analysis of the effects of hydrogen injection from the electrolyzer system, turbine electrical load, and SCR temperature on emissions of nitrogen oxides (NO_x) post catalytic reduction from the combustion turbine.

	Sum of Squares	Degrees of Freedom	Mean Square	F Value	P-value (Prob >F)
A – H_2 (kg/hr)	0.4293	1.0000	0.4293	5.3220	0.0213
B - Load (MWel)	30.3714	1.0000	30.3714	376.5170	< 0.0001
C - SCR Temp (Celsius)	11.2504	1.0000	11.2504	139.4723	< 0.0001
AB	1.4372	1.0000	1.4372	17.8166	< 0.0001
AC	0.0029	1.0000	0.0029	0.0365	0.8485
BC	15.5867	1.0000	15.5867	193.2298	< 0.0001
Model	**4.7770**	**3.0000**	**1.5923**	**81.5634**	**< 0.0001**

Std. Dev.	0.2840	**R-Squared**	0.4212
Mean	1.3543	**Adj R-Squared**	0.4169

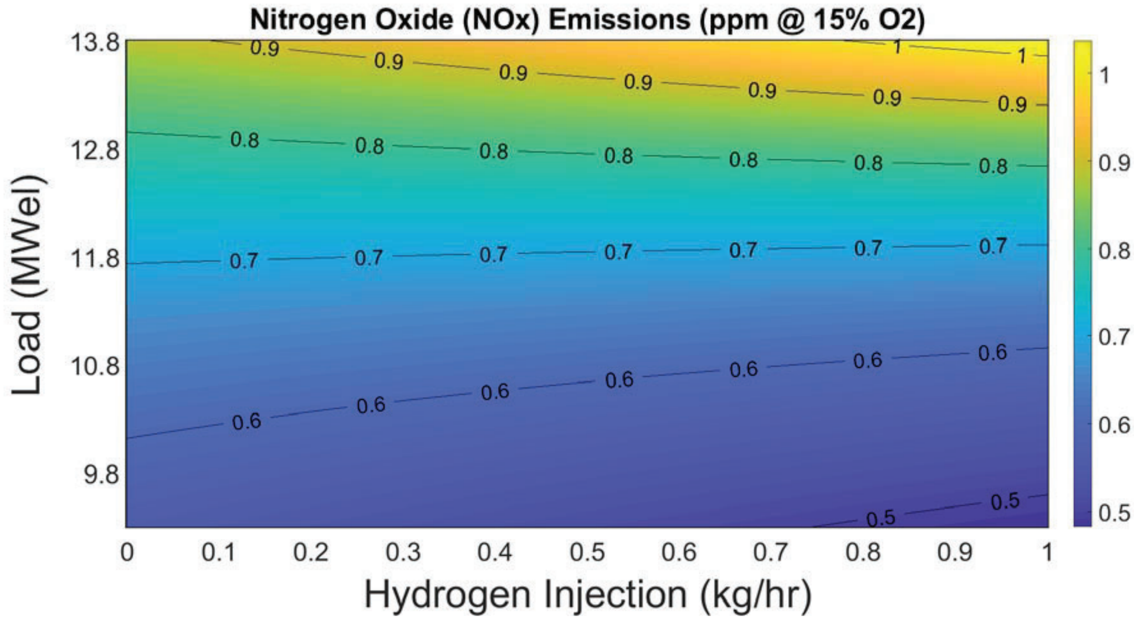


Figure 94. Contour plot of ANOVA predictive model for combined influence of turbine load and hydrogen injection on nitrogen oxides (NO_x) emissions (SCR Temperature = 592 Celsius).

5.2 High Throughput Hydrogen Injection Test

With a maximum observed hydrogen concentration of 0.38% by volume during operation of the electrolyzer system, it was desired to temporarily boost the hydrogen throughput to the injection point and observe the effects on turbine operation in the presence of relatively appreciable amounts of hydrogen.

Through discussion with UCI Central Plant Personnel and Solar Turbines, a maximum allowable limit of 4% by volume hydrogen in natural gas was determined. Due to the possibility of complications involving an essential campus resource, care had to be taken to avoid interrupting campus operations. As a result, the tests were confined to a one-day testing period to be carried out on a previously scheduled turbine shutdown.

To get the most information possible out of the limited test duration, a wide range of load conditions coinciding with the test period was desired. As load influences the responses of interest immensely (emissions of criteria pollutants & total fuel gas flow), repeated test points at a given load are also important. The ability to control the gas turbine load was given through approval from UCI Central Plant personnel, to whatever extent was possible given campus load conditions. Ancillary central plant equipment such as absorption chillers, could be turned off and on by the operator, at request, to impact the total campus load for roughly 1 MW of flexibility in load.

To otherwise maximize the range of turbine load conditions, the test schedule was set for two four-hour periods, from 6 AM to 10 AM to capture the campus ramping from mid-range to high load conditions, and 12 PM to 4 PM to capture minimum load conditions that occur as campus solar PV resources are at their peak. While these test periods seek to give us the broadest range of points possible, a review of June 2017 showed that on average the electrical load was 10.5 MW from 6 AM to 10 AM, and 11 MW from 12 PM to 4PM. Actual load conditions experienced will depend largely on uncontrollable factors.

Normally, for the purposes of eliminating noise in the ANOVA analysis, the level of hydrogen injection would be varied arbitrarily. In this case, to maintain stable operation at the turbine and avoid a premature shut-off, hydrogen output is ramped up and down sequentially between levels. Figure 95 shows the planned hydrogen output test points. Each test point is held at 15 minutes, and repeated twice, for a total test time of two hours during each four-hour period. This is to give a buffer for each four-hour test period.

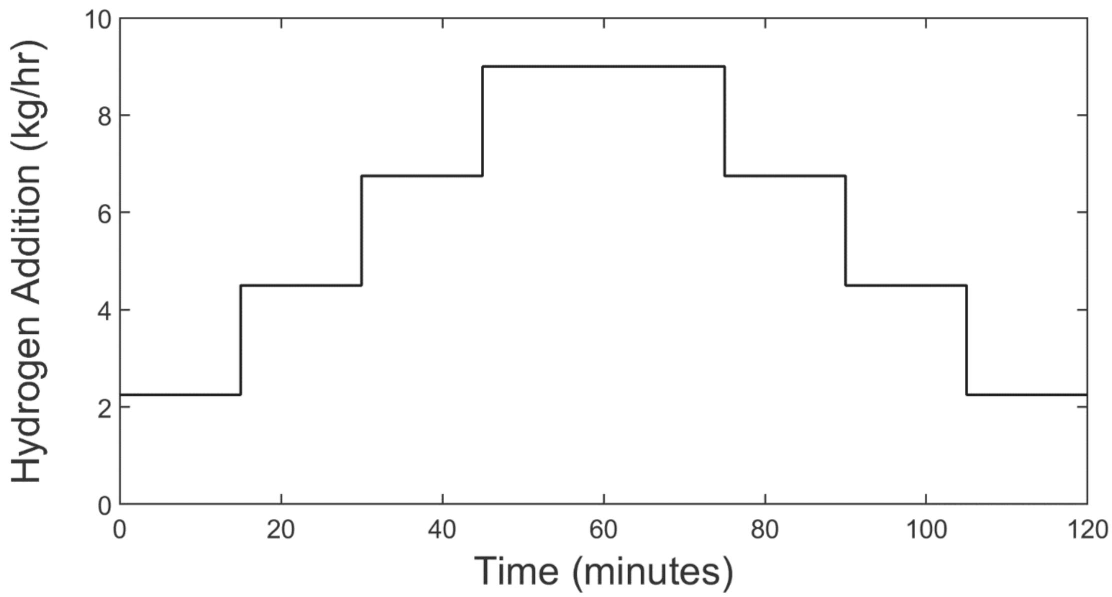


Figure 95. Planned hydrogen injection rates for high throughput hydrogen injection.

A separate injection system was constructed solely for this test. The total amount of hydrogen needed to accomplish the test points is 22.5 kg, with a maximum flow rate spec of 9 kg/hr. The maximum flow rate was determined by readily available equipment, specifically the Sierra Hi-Trak 840 mass flow controller (P/N#: 840H-4-OV1-SV1-D-V4-S4-HP), chosen for the injection system (Figure 96). This flow controller is a scaled-up version of the Sierra Hi-Trak 840H used in the electrolyzer dispatch. The primary difference between the two being a motor driven valve to allow for higher hydrogen throughputs (rated up to 60 SCFM H_2) at the high pressures needed for the injection process.

Figure 96. Sierra Hi-Trak 840 mass flow controller utilized in high throughput hydrogen injection testing.

Calibration of the flow controller was complicated by the large amounts of gas required, and the lack of ability to calibrate 'in-situ' at the Central Plant injection point. Calibrating ex-situ posed the issue of venting large amounts of hydrogen gas without construction of a proper calibration system. Additionally, the cost of the hydrogen needed to carry out multiple rounds of calibration was prohibitive. Linearity of the flow controller and rated flow range was confirmed using nitrogen gas instead due to its availability and its inert nature. The same control system used to dispatch the flow controller for electrolyzer testing was applied here with very little modification due to the similarity in flow controller operation.

A wide range of options for meeting the hydrogen supply were considered, including liquid tankers, gaseous trailer tanks, and gaseous cylinders. Due to restrictions in siting large, concentrated quantities of hydrogen gas, particularly near the natural gas compressor intake co-located with the injection point, gaseous cylinder ‘six-packs’ were selected to meet supply requirements. A 7’x 16’ area of concrete pad was available for siting of the cylinders, which could accommodate 10 size 300 six-packs of hydrogen gas cylinders.

Figure 97. Siting of the six-pack hydrogen cylinders at the UCI Central Plant on concrete pad space.

At the maximum cylinder pressure of 2400 psig (165.5 barg), the total hydrogen capacity of the 60 size 300 cylinders of H_2 is rated at 36.6 kg H_2. With a minimum pressure requirement of 500 psig (34.5) to ensure sufficient pressure drop through the injection system at maximum flow rate, only 28.4 kg of the H_2 is ‘usable’ from the cylinders. Airgas also cautioned that due to the size of the order, size 300 cylinder six packs may need to be substituted with the smaller size 200 six-packs. Each size 200 six pack substituting a size 300 six pack would result in a 0.5 kg H_2

loss, for a possible usable minimum of 23.6 kg H_2 in the event that all six packs are size 200s. As it turned out, Airgas was unable to provide any size 300 six-packs in the end, and total hydrogen supply was rated at the above 23.6 kg H_2.

Figure 98. Pressure regulator and cylinder manifold used in high throughput hydrogen testing.

To reduce the complexity of the injection system, as well as save cost on pressure regulation, all cylinders were manifolded on the high-pressure side, with a single high flow pressure regulator downstream of the cylinder manifold. On the day of testing, the original pressure regulator failed, venting large amounts of hydrogen, and was swapped out with the pressure regulator shown in Figure 98 above. No complications occurred with the second pressure regulator. Relief valve lines were installed up and downstream of the mass flow controller to ensure that lines can be cleared of gas in the event of a flow controller failure. A summary of the entire injection system layout can be found below in Figure 99.

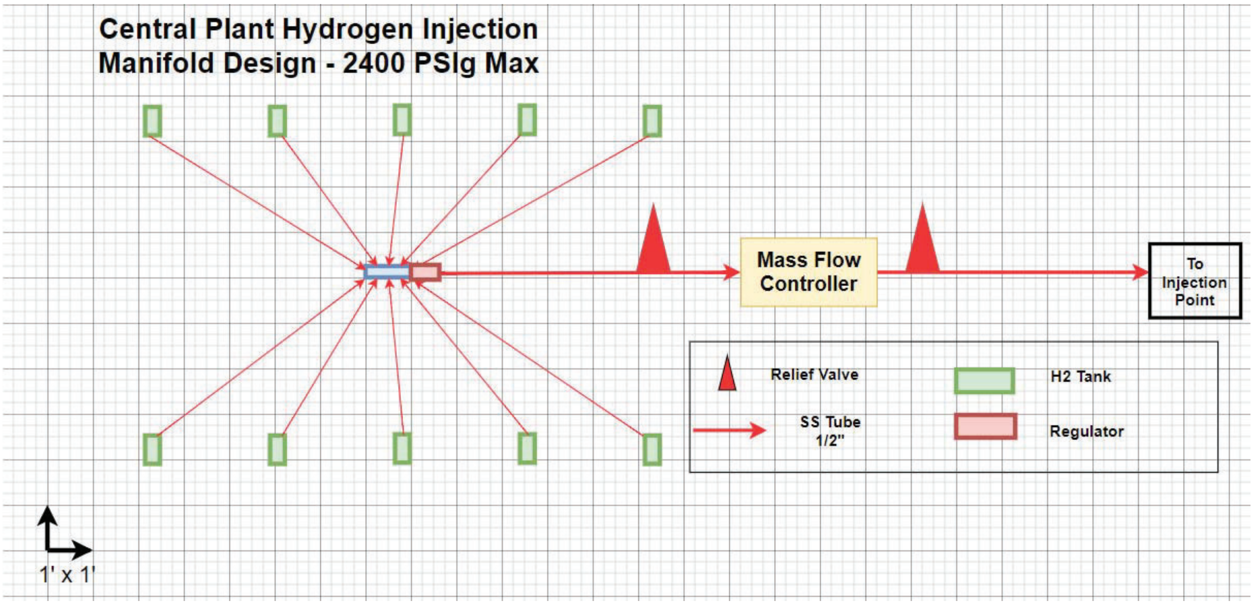


Figure 99. Injection system simplified process flow diagram.

5.2.1 Results

The one-time high throughput test was carried out on June 22nd, 2018. The day before, the injection system was leak tested at working pressures, and all system components were tested at low flow conditions (< 1 kg/hr H_2). On the day of testing, leakage on the output side of the flow controller required that portion of the system to be taken off site and tightened up before proceeding. After reinstalling the flow controller, hydrogen injection commenced at 9:07 AM. Final leakage rates were found to be negligible with respect to the injection rate measurements, estimated at 3 grams H_2 per minute downstream of the flow controller. Leakage upstream of the flow controller was mitigated to the point that it was no longer noticeable through conventional leak testing, but it is likely that small amounts of leakage persisted on the high-pressure side.

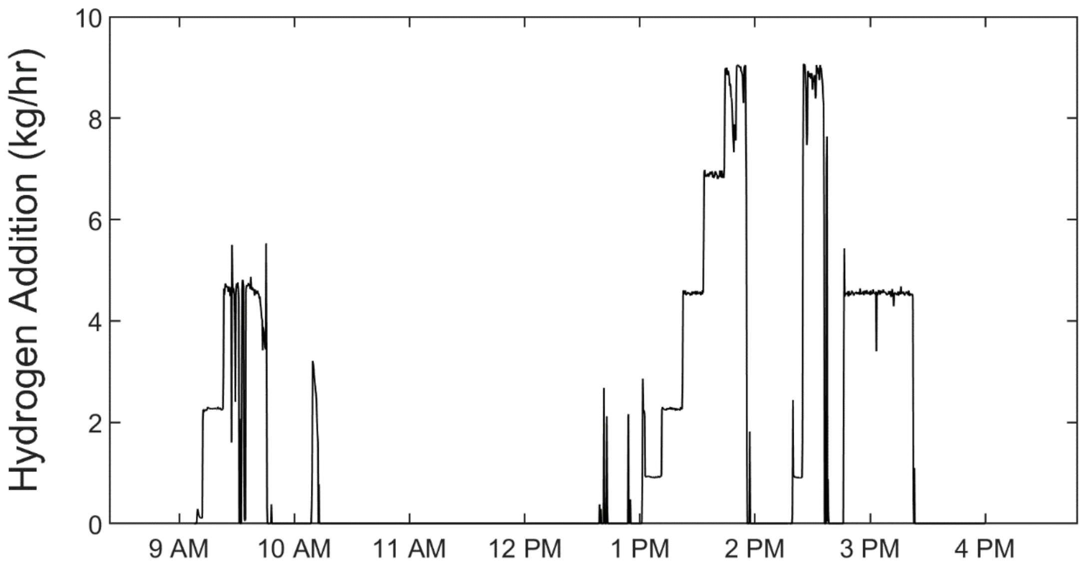


Figure 100. Hydrogen output (kg/hr) from mass flow controller for high throughput hydrogen injection test on June 22nd, 2018.

Figure 100 below shows the hydrogen injection during the day of testing. At 4.6 kg/hr, the pressure regulator prematurely experienced lock out, and could not handle any higher flows while continuing to regulate pressure. The faulty regulator was removed from the line at 10:30 AM, and a new regulator was identified and reinstalled at approximately 12:25 PM. Testing continued at 1 PM, and the new regulator was able to handle the entire flow regime. At maximum flow (9.1 kg/hr H_2) six packs were dropping from full pressure to minimum injection pressure in under 3 minutes. Only one six pack was open at a time during testing to limit the amount of hydrogen that would escape in the event of a critical injection failure. These two factors combined meant that at full flow, the pressure regulator had to be actively adjusted to maintain output pressure and by extension the flow rate. Additionally, cylinders had to be opened in-situ to keep up with the flow rate. For this reason, the maximum flow regime periods were relatively unstable. A total of 11.5 kg of H_2 was injected, far short of the expected 23.6 kg of H_2 available with all size 200 cylinders. All cylinders were observed to be somewhat short of the 2000 psig 'full' rating, and some cylinders were exhausted during the pressure testing of the lines and the initial pressure regulator failure. Combined with a small amount of leakage upstream of the flow controller, this likely accounts for the disparity in hydrogen amounts.

Due to higher than average temperatures and high relative humidity with respect to weather, the campus load remained higher than average throughout the day. Figure 101 shows the turbine electrical load and fuel gas flow for the duration of the injection testing. The minimum load set point for the day was 11 MW_{el}, during which the average minimum fuel gas flow was 2562 kg/hr. From 2 PM to 4 PM the Central Plant operator was able to take one adsorption chiller down to step down the load to the 11 MW_{el} mark for a short period of time, and then ramped up the chiller in the stepwise pattern shown to 11.8 MW_{el}. The shutdown schedule proceeded on time; spin-down began at approximately 3:30 PM.

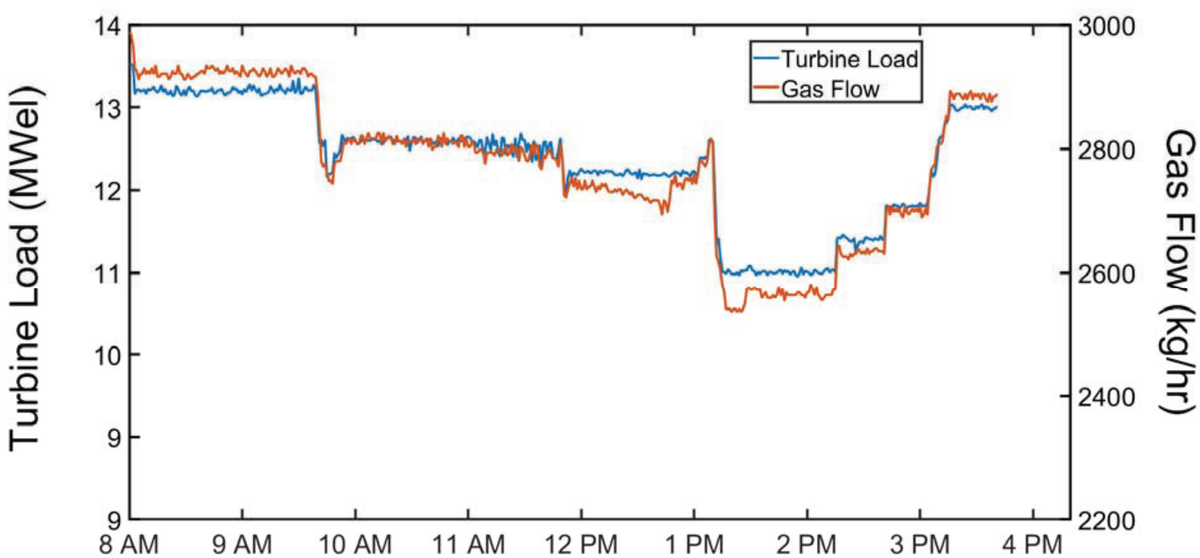


Figure 101. Turbine electrical load and gas flow during high throughput hydrogen injection test on June 22nd, 2018.

The resulting volumetric concentrations of hydrogen in balance with natural gas is shown below in Figure 102. A maximum observed concentration of 3.4% by volume fell well short of the 4% by volume upper limit, largely due to the limited range of turbine load on the day of testing. The total range of data matches poorly with the expectations set in Figure 95, however given the nature of the test this was not an unexpected result.

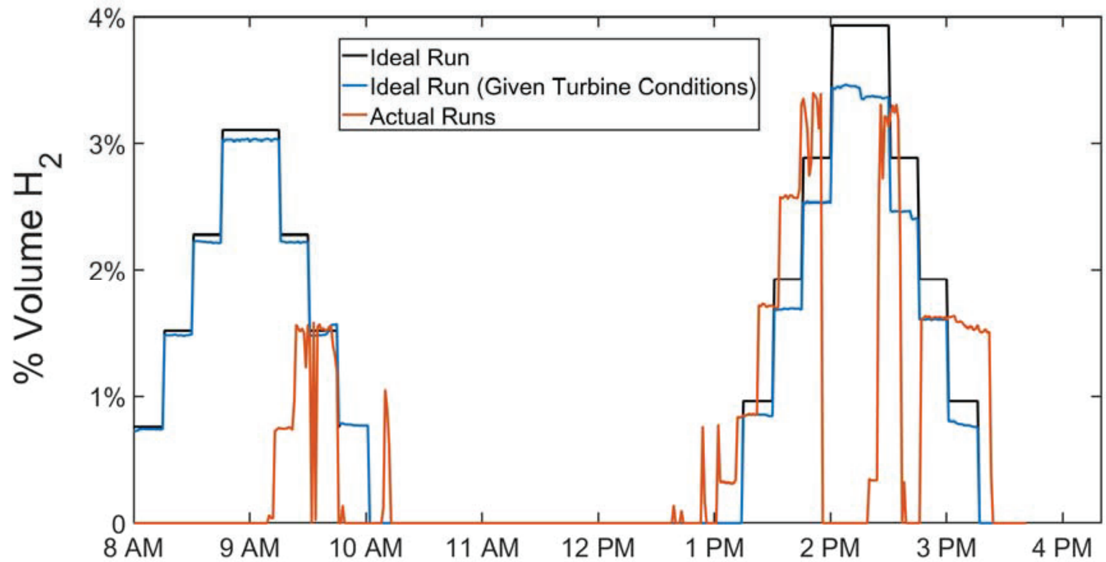


Figure 102. Percentage of hydrogen in fuel gas flow to combustion turbine at UCI Central Plant during high throughput hydrogen injection test on June 22nd, 2018.

5.2.2 Effects of Hydrogen Addition on Gravimetric Gas Flow to Turbine

Similar to what was previously observed from the electrolyzer-based injection testing, the influence of hydrogen addition on the natural gas fuel flow remains questionable, even at sustained flow rates of ten times larger than the electrolyzer output. Table 20 displays the results of the ANOVA for the observed variation in fuel gas flow. The load condition of the turbine again dominates as the predicting variable, and the SCR temperature was included in the analysis as its variation better explained the small variations in fuel gas flow at sustained load conditions. As a result, the addition of SCR temperature helped reduce obfuscation of the predicted effects that hydrogen addition had on fuel gas flow.

Table 20. Summary of ANOVA analysis of the effects of hydrogen injection from the high throughput hydrogen injection testing on net gravimetric fuel gas flow.

	Sum of Squares	Degrees of Freedom	Mean Square	F Value	P-value (Prob >F)
A – H_2 (kg/hr)	55.3801	1.0000	55.3801	1.5490	0.2352
B - Load (MWel)	2.73E+05	1.0000	2.73E+05	7624.6844	< 0.0001
C - SCR Temp (Celsius)	212.1363	1.0000	212.1363	5.9337	0.0300
AC	121.4296	1.0000	121.4296	3.3965	0.0882
Model	**316047**	**4.0000**	**79012**	**2210**	**< 0.0001**

Std. Dev.	5.9792	**R-Squared**	0.9985
Mean	2722.6169	**Adj R-Squared**	0.9981

Figure 103 displays the trend in fuel gas flow as a function of turbine load and hydrogen addition as predicted by the ANOVA model. At zero hydrogen addition, the total amount of fuel gas flow for a given load condition was observed to be higher on average than what was found in the larger injection study (Figure 90). Given that the high throughput testing was carried out on the last day of preceding scheduled quarterly maintenance, when turbine performance is generally at its lowest, this is to be expected. The range of turbine load conditions observed was limited as well, narrowing the study to the range of 11 MW_{el} to 13.2 MW_{el}.

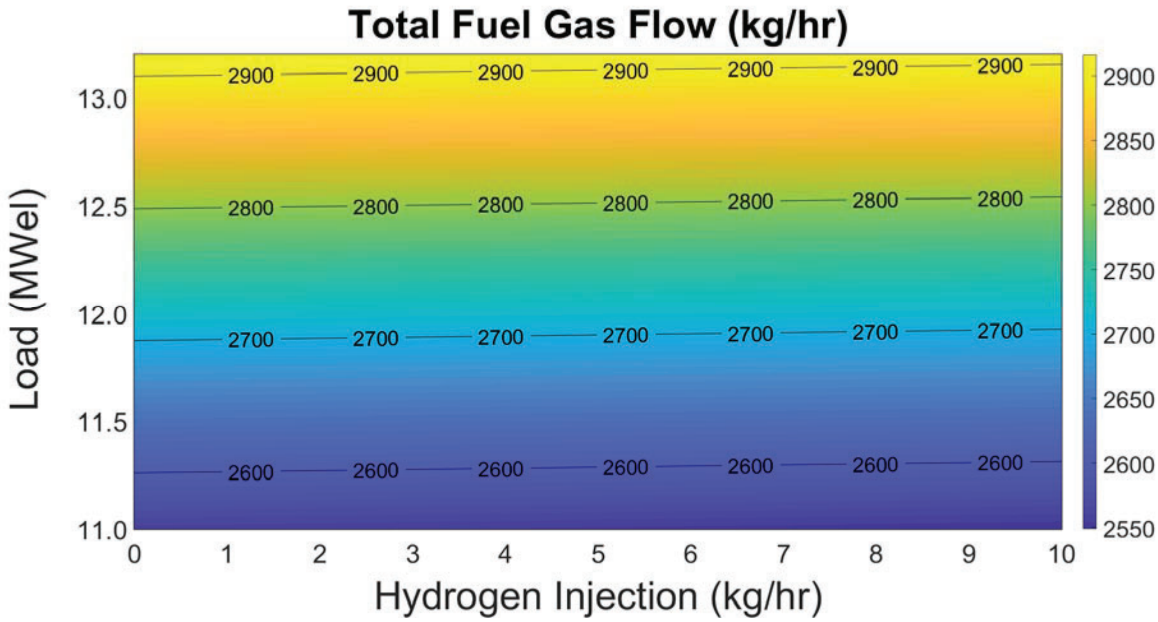


Figure 103. Contour plot of ANOVA predictive model for combined influence of turbine load and hydrogen injection on total fuel gas flow for high throughput hydrogen testing.

The predicted offset in natural gas as a result of the ANOVA analysis is shown below, compared against the heat balance prediction (Figure 104). Unfortunately, the wide range of hydrogen injection did not result in a stronger trend for hydrogen addition influencing fuel gas flow. The agreement is not as strong as what was previously observed in the electrolyzer injection study, but the general trend is similar. The 95% confidence intervals are much larger, giving an average offset of 1.9 kg of natural gas usage per kg of H_2 added, varying from 0.04 kg up to 3.75 kg of natural gas for the highest confidence intervals around 2.2 kg/hr hydrogen flow rate. This is lower than what was previously observed, but within the wide range of uncertainty previously observed as well. The wide uncertainty range can be seen as a result of the low significance of hydrogen addition in predicting fuel gas flow.

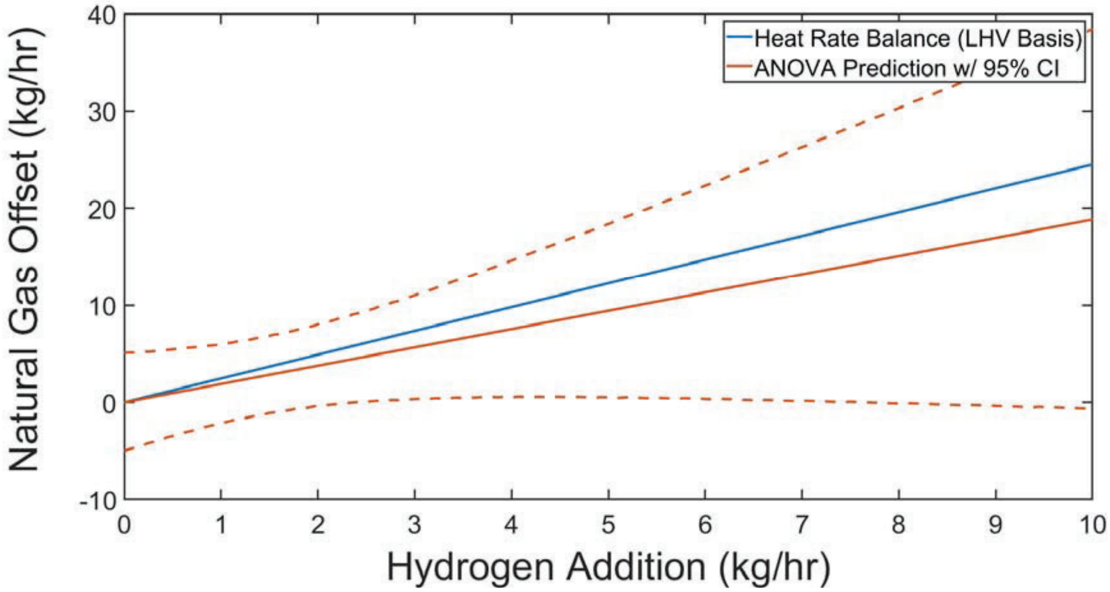


Figure 104. Predicted natural gas offset due to hydrogen injection from ANOVA analysis with 95% confidence intervals versus expected natural gas offset on a lower heating value basis for high throughput hydrogen testing.

5.2.3 Effects of Hydrogen Addition on Carbon Monoxide (CO) Emissions

Emissions of carbon monoxide did not vary appreciably throughout the day of testing, only varying between 1.05 and 1.08 ppm @ 15% O_2 (as opposed to historical observations varying between 0.6 up to 1.5 ppm @ 15% O_2). As a result, no correlation of significance for CO emissions can really be drawn outside of the definite positive correlation with turbine load. For posterity, the results of the ANOVA analysis are shown below in Table 21. The contour plot of the ANOVA model for the effects of turbine load and hydrogen addition is shown in Figure 105. This lack of observed variation in emissions reinforces the supposition that hydrogen addition in the ranges studied does not have any influence on carbon monoxide emissions for a combustion turbine with catalytic clean-up.

Table 21. Summary of ANOVA analysis of the effects of hydrogen injection from the high throughput hydrogen injection testing on post catalytic clean-up carbon monoxide emissions.

	Sum of Squares	Degrees of Freedom	Mean Square	F Value	P-value (Prob >F)
A – H_2 (kg/hr)	0.0001	1.0000	0.0001	2.8022	0.1223
B - Load (MWel)	0.0005	1.0000	0.0005	13.3244	0.0038
C - SCR Temp (Celsius)	< 0.0001	1.0000	0.0000	0.0753	0.7888
AB	< 0.0001	1.0000	0.0000	0.6445	0.4391
AC	0.0001	1.0000	0.0001	1.6531	0.2249
BC	0.0001	1.0000	0.0001	4.1257	0.0671
Model	**0.0012**	**6.0000**	**0.0002**	**5.7336**	**0.0063**

Std. Dev.	0.0060	**R-Squared**	0.7577
Mean	1.0675	**Adj R-Squared**	0.6256

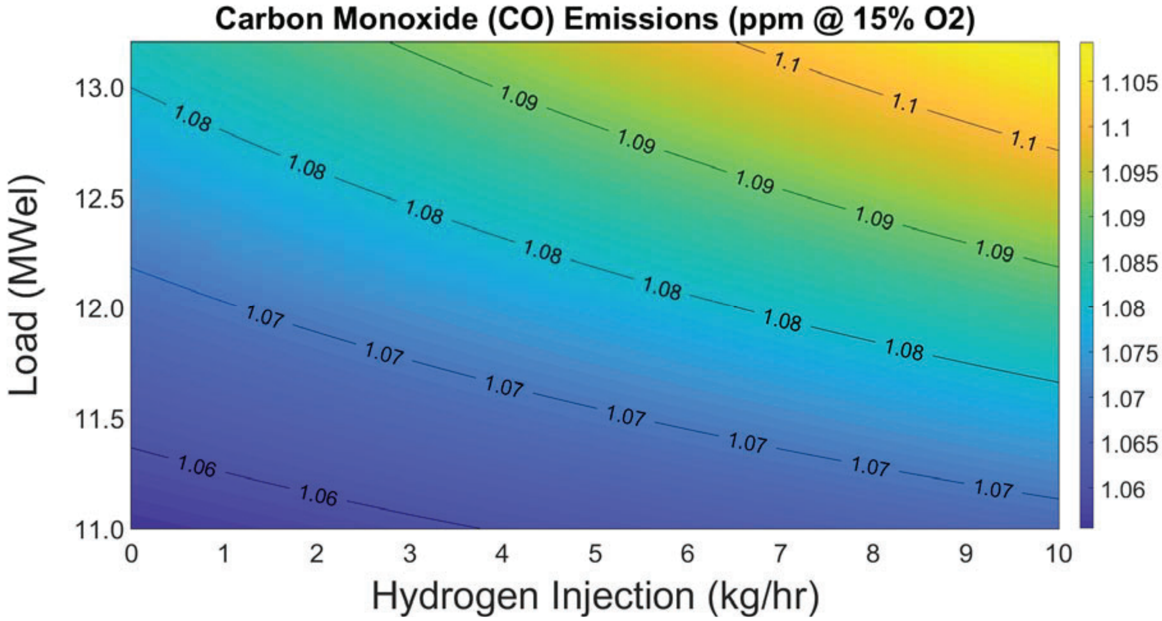


Figure 105. Contour plot of ANOVA predictive model for combined influence of turbine load and hydrogen injection on carbon monoxide emissions for high throughput hydrogen testing.

5.2.4 Effects of Hydrogen Addition on Emissions of Nitrogen Oxides (NO_x)

Emissions of nitrogen oxides did not vary appreciably throughout the day of testing, limited to an observed range of 0.5 to 0.8 ppm @ 15% O_2. For this reason, no significant correlation for the factors of interest had any appreciable impact on nitrogen oxide emissions. Table 22 summarizes the ANOVA analysis for nitrogen oxide emissions, with no stand-out variables for explaining the variance in nitrogen oxide emissions. Figure 106 shows the contour plot of nitrogen oxide emissions as a function of turbine load and hydrogen addition as predicted by the ANOVA model. The trends shown in Figure 106 are highly likely to not be indicative of the actual effects of these factors on nitrogen oxide emissions due to the low strength of the model. This result reinforces the previous results that hydrogen addition does not have any impact on the ultimate nitrogen oxide emissions and combined with the results for the carbon monoxide emissions, does not affect emissions of criteria pollutants from the combustion turbine and its pollution controls.

Table 22. Summary of ANOVA analysis of the effects of hydrogen injection from the high throughput hydrogen injection testing on post catalytic clean-up nitrogen oxide emissions.

	Sum of Squares	Degrees of Freedom	Mean Square	F Value	P-value (Prob >F)
A – H_2 (kg/hr)	0.4293	1.0000	0.4293	5.3220	0.0213
B - Load (MWel)	0.0188	1.0000	0.0188	4.8218	0.0504
C - SCR Temp (Celsius)	0.0161	1.0000	0.0161	4.1237	0.0672
AB	0.0494	1.0000	0.0494	12.6690	0.0045
AC	0.0019	1.0000	0.0019	0.4907	0.4982
BC	0.0131	1.0000	0.0131	3.3539	0.0942
Model	**0.1020**	**6.0000**	**0.0170**	**4.3590**	**0.0170**

Std. Dev.	0.0624	**R-Squared**	0.7039
Mean	0.6032	**Adj R-Squared**	0.5424

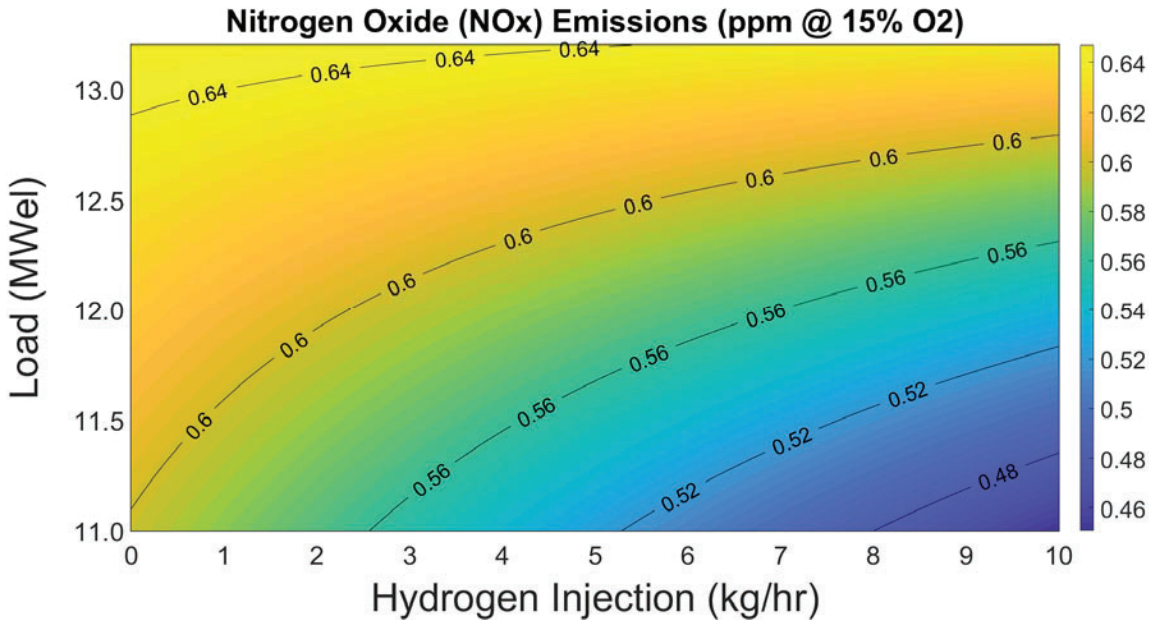


Figure 106. Contour plot of ANOVA predictive model for combined influence of turbine load and hydrogen injection on nitrogen oxide emissions for high throughput hydrogen testing.

5.3 Summary & Recommendations

To meet ambitious renewable electricity generation requirements, particularly at penetrations of 80% and above, massive energy storage technologies are required. Furthermore, natural gas infrastructure is critical in the transitioning to higher renewable energy profiles. Power-to-gas can provide both massive energy storage and an incremental pathway to decarbonization of existing natural gas infrastructure. One way it can accomplish is through the direct injection of hydrogen gas to the gas grid. The wide range of natural gas end-uses present on the gas grid requires in-depth studies on their suitability for hydrogen blended natural gas utilization.

The first demonstration of this power-to-gas based injection process was accomplished in the United States in this study, with over 4000 hours of injection to the gas infrastructure accomplished to date. The impact of this hydrogen addition on emissions of the gas turbine downstream of the injection point was analyzed. In the long-term, for limited concentrations of hydrogen (< 0.5% by volume in natural gas), there is no discernible impact on emissions of criteria pollutant emissions. The offset of natural gas fuel usage was found to be 2.50±1.75 kg natural gas per kg of hydrogen, and by extension the reduction in CO_2 emissions was in the range of 6.73±4.71 kg of CO_2 per kg of hydrogen. This offset of natural gas by hydrogen addition matches well with the predicted offset of 2.46 kg of natural gas per kg of H_2 added on an energy balance basis. A short-term, increased throughput round of testing showed similar results, achieving up to 3.4% by volume H_2 in natural gas without any discernible impact on emissions of criteria pollutants. The offset of natural gas fuel flow observed was slightly lower than what was previously observed in the long-term, though still well within range of the long-term study results.

The results obtained are encouraging for the addition of small amounts of hydrogen to the greater gas grid, particularly in that combustion turbines are one of the more complex and by extension fuel quality sensitive end-uses present on the gas grid. There is still need for extensive testing of all currently present end-uses before continuing to wider, public gas grid injections of hydrogen. Work already in progress in the European Union is encouraging for the injection of such quantities to the greater gas grid even at the transmission level. In California, and the greater United States, there is still need for regulation on allowable hydrogen concentrations in natural gas for blending purposes, which requires studies such as this to draft.

5.3.1 Observations

- The regular variation in composition that occurs in pipeline natural gas heavily influences the extent to which hydrogen can be blended into natural gas using current Southern California Gas Rule 30 standards for customer owned gas injection. Using the national average for natural gas quality, up to 19% H_2 by volume hydrogen can be blended with natural gas on a Wobbe Index basis. Based off measured pipeline values in the southern California region, this amount could vary from 13% up to 27% by volume H_2. On a higher heating value basis using Rule 30, this amount could vary 1% up to 23% by volume H_2.
- On a lower heating value basis, one kg of hydrogen offsets the energy throughput of 2.45 kg of natural gas. Assuming complete combustion, the combustion of 1 kg of natural gas results in the emission of 2.67 kg of CO_2. Thus, the net offset on an energetic basis, is 6.54 kg of CO_2 per kg of H_2.

- Hydrogen concentrations as high as 0.46% by vol H_2 in natural gas to the combustion turbine were observed over the 4000 hours of electrolyzer system operation. The one-time high throughput hydrogen testing achieved sustained concentrations as high as 3.4% by volume H_2 without any adverse effects on turbine operation.
- ANOVA analysis across 1 hour sustained hydrogen injection data from the electrolyzer operation ($n = 1000$) showed an average offset of 2.5 ± 1.75 kg natural gas per kg of H_2. Analysis of the results for the one-time high throughput hydrogen testing showed average offsets of 1.9 ± 1.85 kg natural gas per kg of H_2.
- The addition of hydrogen gas to the natural gas fuel feed to the combustion turbine did not have any statistically significant influence on the final stack emissions of carbon monoxide and nitrogen oxides.

5.3.2 Recommendations

This study demonstrated the direct injection of hydrogen gas produced from a VRES load following electrolyzer system to a natural gas pipeline feeding a gas-fired combustion turbine. From the assessed impacts on turbine emissions and performance, the following recommendations can be made.

- Construction of larger power-to-gas plants is needed to better assess the impacts of hydrogen end-use by producing appreciable amounts of hydrogen, additionally larger PEM electrolyzer systems would mitigate balance of plant inefficiencies, particularly from hydrogen drying.
- Limits on acceptable hydrogen quantities in natural gas for the entire spectrum of natural gas end-uses is needed.
- Begin introducing renewable hydrogen gas incrementally into the natural gas system in increasing quantities as end-use suitability is assessed and approved to see immediate carbon emission offsets.

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Amended Hydrogen Blending Demonstration Application (A.22-09-006)
Sierra Club DR-04

Attachment 17

PROTECTED MATERIALS

From:	[redacted]
To:	
Subject:	FW: Joint Utilities H2 Blending Stakeholder Workshop Question Follow Up
Date:	Tuesday, April 2, 2024 2:45:20 PM
Attachments:	H2 Blending Stakeholder Workshop Presentation.pdf H2 Blending Stakeholder Workshop Question Follow Up.pdf

[redacted]

From: [redacted]
Sent: Monday, July 24, 2023 9:57 AM
To: [redacted]
Subject: Joint Utilities H2 Blending Stakeholder Workshop Question Follow Up

Good morning,

As a follow up to the H2 Blending Stakeholder Workshop, we wanted to provide responses to the submitted Q&A's that we did not have time to officially respond to during the workshop. We have attached written responses to those questions.

Again, we appreciate you taking the time to participate in the workshop, and look forward to working with you as the blending pilot projects proceed.

Best Regards,

[redacted]
Regulatory Business Manager
Cell: [redacted]
Email: [redacted]

SoCalGas A Sempra Energy utility

From: [redacted]
Sent: Friday, June 16, 2023 12:03 PM
Subject: Joint Utilities H2 Blending Stakeholder Workshop Presentation

Good afternoon,

Attached you will find the presentation that was shared during the H2 blending pilot project stakeholder workshop. We appreciate you taking the time to participate.

Best Regards,

PROTECTED MATERIALS

[redacted]
Regulatory Business Manager
Cell: [redacted]
Email: [redacted]

SoCalGas A Sempra Energy utility

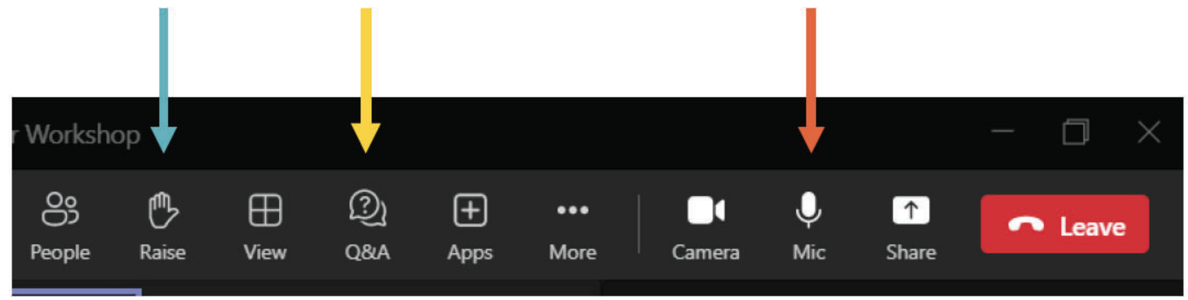
Joint Utilities Hydrogen Blending Pilot Project Stakeholder Workshop

June 13th, 2023

Agenda

- 1:00 PM - 1:05 PM Welcome and Housekeeping
- 1:05 PM - 1:20 PM Overview & Context Setting
- 1:20 PM - 1:45 PM UC Riverside Presentation
- 1:45 PM - 2:25 PM Utility Project Presentations
  - SoCalGas
  - SDG&E
  - Southwest Gas
  - PG&E
- 2:25 PM - 2:45 PM ATCO Gas
- 2:45 PM - 3:30 PM Stakeholder Feedback

Feedback Instructions



- There are two ways to submit questions:
  - via the **Q&A function** — Can be submitted any time during workshop
  - via the **Raise [Hand] function** — Will only be "called on" during Feedback Session, from 2:45-3:30.

Please include your name and your organization's name before providing questions or feedback

Purpose and Scope

Purpose

To comply with D.22-12-057, Ordering Paragraph 11

Description

Within six months from the issuance date of this decision, Pacific Gas and Electric Company, Southwest Gas Corporation, Southern California Gas Company, and San Diego Gas & Electric Company shall coordinate with the Commission's Energy Division and host a workshop to **obtain feedback from a diverse group of stakeholders regarding <u>how to proceed with assembling safe and meaningful pilot projects</u> for testing of hydrogen blends and <u>how to assess environmental impacts to customers and communities</u>, including disadvantaged communities: among other inputs received, the <u>workshop must inform the design and implementation of the pilot projects' necessary testing and monitoring systems</u>**, as well as address any potential need to implement partial pressure limits in future tariff updates in order to preserve pipeline integrity while performing any and all required testing.

Background and History

- Hydrogen is a carbon-free gaseous energy carrier that may be an important part of a reliable, low carbon future for the state
- Currently no hydrogen is permitted to be purposefully blended in CA's natural gas system
- awcooper@ucsd.edu Adam COoper

Nov 2019	**R. 13-02-008 (Biomethane Proceeding), Phase 4 Scoping Ruling "should establish safe standards that will enable injection of renewable H2 into gas pipelines to reduce the carbon intensity of the gas used in the state."**
Nov 2020	**A.20-11-004 (SCG, SDG&E, SW Gas, PG&E) filed application for memo accounts to study the issue**
July 2021	**A.20-11-004 Dismissed without prejudice**
July 2022	**CPUC Directed UC Riverside Report is published: "*It is critical to conduct real world demonstration of hydrogen blending*"**
Sept 2022	**A.22-09-006 (SCG, SDGE, SWG) filed requesting approval for specific distribution blending projects**
Dec 2022	**D.22-12-057 directed all the Joint Utilities to amend or refile pilot programs to test H2 blending in natural gas at concentrations of 0-5% (open) and 5-20% (closed).**
June 2023	**Joint Utility Stakeholder Workshop (SCG, SDG&E, SW Gas, PG&E)**
2023/2024	**Pilot Requests Filed (SCG, SDG&E, SWG, PG&E)**

Ongoing Stakeholder Engagement

Dec 2022
CPUC Rulemaking 13-02-008, D.22-12-057

Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions.

A. Ensures long-term safety of the California pipeline	B. Prevents H2 from reaching natural gas storage areas	C. Avoids end user appliance malfunctions	D. Evaluates hydrogen blends between 0-5% and 5 to 20%
E. Project application must specify funding amounts	F. Consistent with directed courses of action	G. Testing protocols consistent with the UCR Study	H. Takes stakeholder input into account
I. Propose Hydrogen Blending System Impact Analysis Methodology	J. Heating value considerations	K. Leakage detection, rigorous leak testing protocols	L. Independent research plan

Introductory Remarks

Neil Navin
Chief Clean Fuels Officer
SoCalGas

UCR | College of Engineering- Center for Environmental Research & Technology

Hydrogen Blending into Natural Gas Infrastructure

Arun Raju, Ph.D.

Center for Environmental Research and Technology

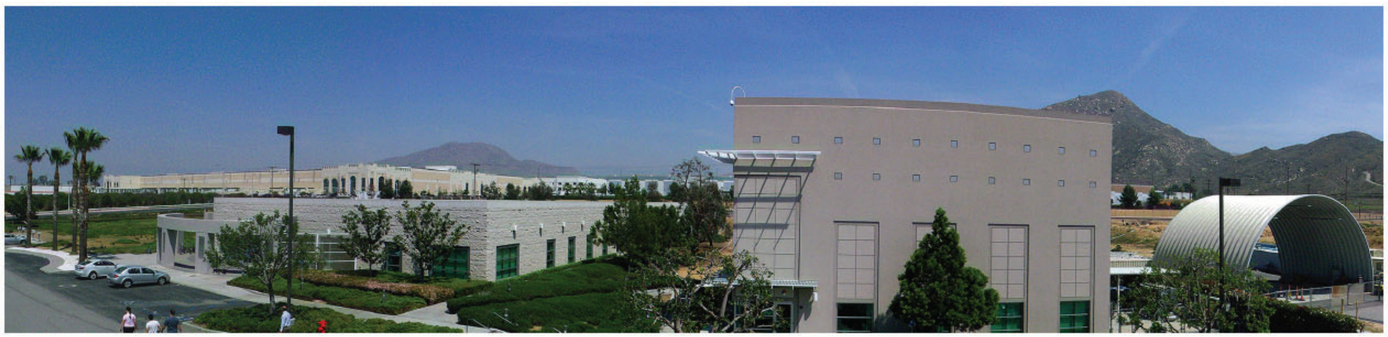
UC Riverside

https://www.cert.ucr.edu/

June 2023

CE-CERT

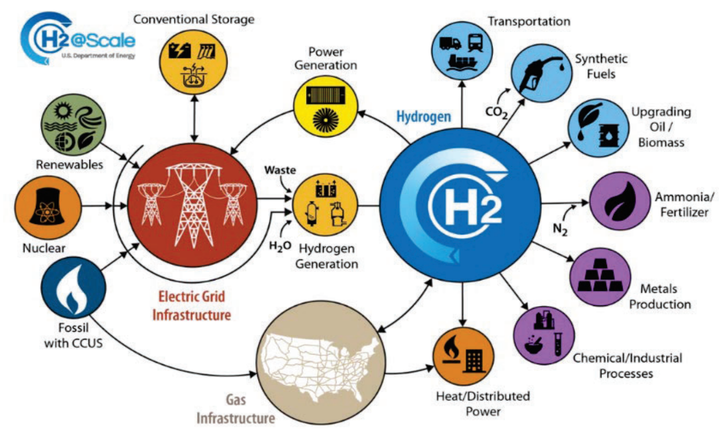
CE-CERT is dedicated to addressing society's most pressing environmental challenges in air quality, climate change, energy and transportation through research, education and public service

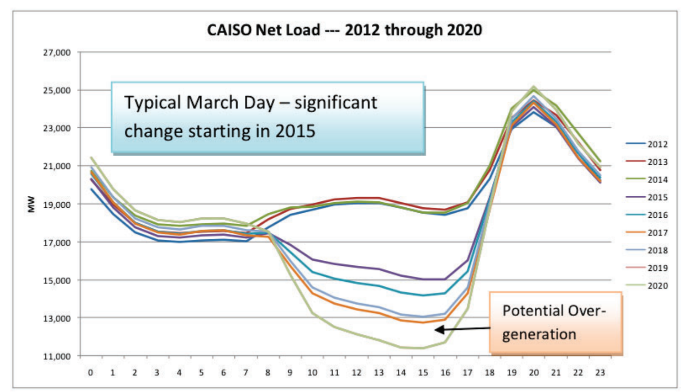


- 150 student employees
- 60 faculty & engineers
- $ 30 million in ongoing research
- 30 laboratories and testbeds

Why Hydrogen?

- Decarbonization needs are diverse and complex
  - Electrons and molecules are needed – renewable electricity and fuels
  - Heavy duty transportation, industry, and other sectors
- Critical need for energy storage over the next decades
  - Batteries offer short term energy storage
  - Hydrogen (power to gas) – mid to long term, “seasonal” energy storage
- Hydrogen offers a path to transition to a carbon free energy future
  - Potential to address greenhouse gas and criteria pollutant, toxic emissions





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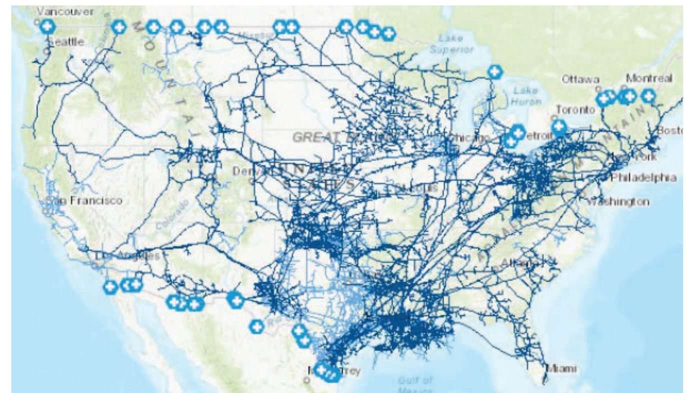
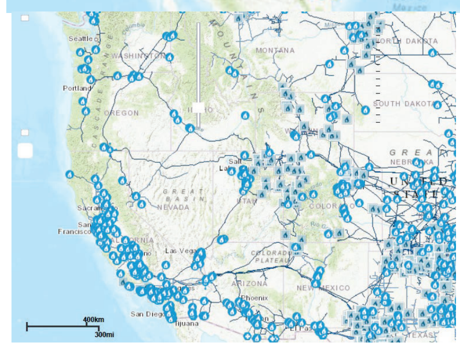
Decarbonizing the Natural Gas Infrastructure

- Multiple energy infrastructures – petroleum, natural gas, electric
  – Reliability, resiliency and availability
- Hydrogen blending with natural gas
  – Opportunity to decarbonize the pipeline infrastructure
  – Accelerate hydrogen production and use
  – Avoid building hydrogen infrastructure from scratch
  – Complemented by distributed hydrogen production and use

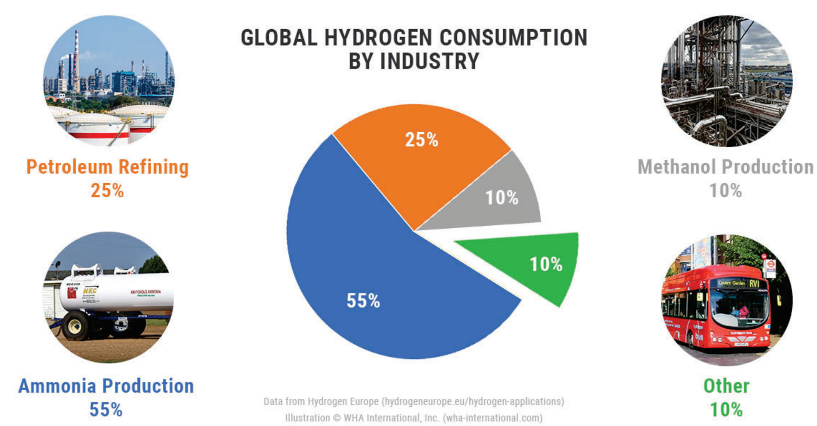




https://www.eia.gov/state/maps.php

Hydrogen Industry Today

- Hydrogen industry is mature and global
  - Produced by steam reforming of fossil natural gas
  - Used in petroleum industry, fertilizer and chemicals production
- Codes, standards and protocols are well established for handling, storage and transportation
  - Hydrogen pipelines in the US ~ 1600 miles
- Renewable hydrogen production and use is expanding
  - Can be produced by splitting water into hydrogen and oxygen using renewable electricity - electrolysis
  - Other carbon neural pathways are available (ex. Biomass conversion)



https://wha-international.com/hydrogen-in-industry/

Hydrogen Blending into Natural Gas Infrastructure

- Hydrogen blending offers potential to
  - Expedite the transition to a carbon free energy future
    - Decarbonize multiple energy sectors
  - Use existing, mature infrastructure for the transition

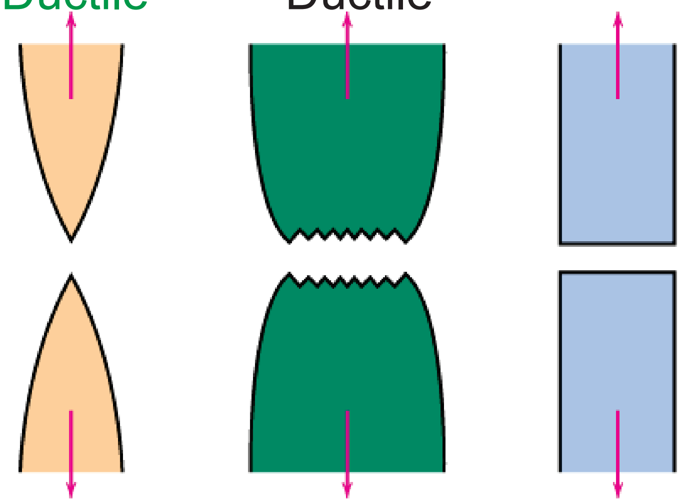
- Challenges
  - Hydrogen properties are different from other fuels including natural gas
    - Combustion properties and energy content
  - Compatibility with materials used in natural infrastructure including pipelines
    - Leakage rates, embrittlement, and other concerns

- Integrity of existing natural gas infrastructure is a primary concern
  - Hydrogen embrittlement effects depend on operating conditions such as pressure, temperature, cycle loading, etc. Thus, it is more appropriate to use hydrogen partial pressure, rather than hydrogen concentration in the gas blend to assess potential impacts

Embrittlement & Fracture

- Fracture can result from
  - Materials selection & processing
  - Inadequate design
  - Misuse
- Fracture involves
  - Crack Formation
  - Crack Propagation
- Fracture - separation into $\geq$ 2 pieces
  - **Ductile**
    - Accompanied by significant plastic deformation
  - **Brittle**
    - Little or no plastic deformation
    - Catastrophic

Ductile vs Brittle Failure



- **Ductile failure:**
  -- one piece
  -- large deformation

- **Brittle failure:**
  -- many pieces
  -- small deformations

- Ductile fracture is usually more desirable than brittle fracture!

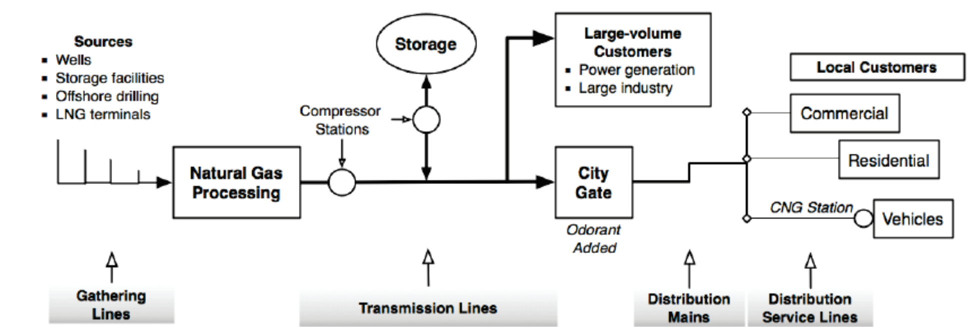
Ductile: Warning before fracture

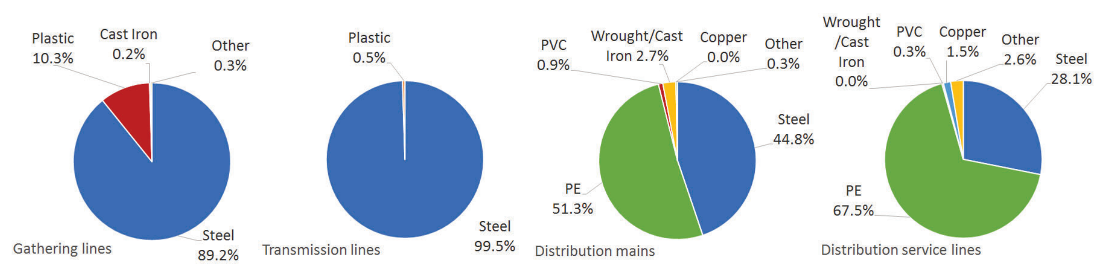
Brittle: No warning

Adapted from Fig. 8.1, *Callister & Rethwisch 9e.*

Hydrogen Blending Efforts Ongoing

- R&D and demonstration projects are underway
  - Evaluate impacts under real world conditions
  - Europe, Australia and other jurisdictions
  - Hawaii has ~12% hydrogen in natural gas mix (not a demonstration project)
  - California's future energy mix will need hydrogen to play a role





Pictures from or reproduced based on NREL report by Melaina et al. 2013

UCR Hydrogen Blending Impacts Study

Sponsor: California Public Utilities Commission (CPUC)

Goal: Assess safety concerns associated with injecting hydrogen into the existing natural gas pipeline system at various percentages

Tasks

- Literature survey
- Potential impact of hydrogen injection on the natural gas infrastructure
  - Leakage rates
  - Impacts on degradation, durability/integrity of the existing natural gas pipeline system
  - Impact on valves, fittings, materials, and welds due to hydrogen embrittlement
- Maximum hydrogen blending potential evaluation

Tensile strength

Impact resiliency

Hardness

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Recommendations

Conduct real world demonstrations – recommend 5-20% blending

	Year 1	Year 2	Year 3
A. Large Scale Demonstration		Lead: Utilities	
B. Laboratory R&D		Lead: R&D Organizations	
C. Planning Activities		Lead: State Agencies	
D. Stakeholder Engagement		Lead: State Agencies/Community Organizations	

Key Activities:

A. Demonstrations: Blending under real world conditions over extended periods, develop and demonstrate mitigation strategies to address safety and performance issues

B. R&D: Address knowledge gaps and assess higher hydrogen percentages blending, mitigation strategies, support demonstration activity

C. Planning: Develop inventories, update and develop specifications, safety/maintenance protocols, workforce development

D. Engagement: Understand priorities and concerns, outreach and consensus building

Next Steps - Demonstrations

- Laboratory scale analytical data available on several of the materials and many of the components
- Operational data – real world, over long periods – is lacking
  - Including under California infrastructure conditions
  - Presence of non-methane species, including contaminants, RNG injection
  - California weather effects, system pressure and volume fluctuations
  - Range of end use customers and purposes
  - Gas storage and handling
- With the exception of Hawaii Gas, there are no system-wide operational efforts in North America
  - Hawaii has experience in up to 15% hydrogen ~22 miles of transmission, and total of 1,100 miles of network (California has over 100,000 miles)
  - European efforts can help guide design of demonstrations, design blending and end use strategies, and protocols

Next Steps - Demonstrations

- Demonstrations provide opportunity to:
  - Address knowledge gaps
  - Develop and implement maintenance and safety training and protocols
  - Engage suppliers, vendors and develop and implement upgrading and replacement of infrastructure components
  - Develop and implement end use equipment operational, safety, and maintenance
  - Engage stakeholders, customers, and the community and develop consensus

Related Links:

- H$_2$ Safety Best Practices – This website compiles best practices for hydrogen safety.
https://h2tools.org/bestpractices/best-practices-overview
- Hydrogen Distribution and Delivery Infrastructure – This fact sheet provides an overview of hydrogen fuel distribution and delivery.
https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/doe_h2_delivery.pdf
- Hydrogen Fueling—Coming Soon to a Station Near You – This fact sheet provides an overview of hydrogen fueling station permitting, codes, and standards.
https://www.nrel.gov/docs/fy09osti/45407.pdf
- Hydrogen Production – This fact sheet explains the basics of hydrogen production technologies.
https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/doe_h2_production.pdf
- Hydrogen Safety – This Department of Energy Web site offers hydrogen first-responder training and a hydrogen safety bibliographic database.
https://www.hydrogen.energy.gov/safety.html
- Hydrogen Safety – This fact sheet summarizes the properties of and safety issues associated with hydrogen.
https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/doe_h2_safety.pdf
- Hydrogen Storage – This fact sheet provides an overview of hydrogen storage technologies.
https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/doe_h2_storage.pdf

Contact: arun@engr.ucr.edu
https://www.cert.ucr.edu/

Project Presentations

Kevin Woo	Pooyan Kabir, PhD	Ariana Frame	Jamie Randolph
Hydrogen Research Manager	Senior Hydrogen Engineer	Distribution Engineer	Principal Hydrogen Program Manager

Project Safety Considerations

- Project equipment and designs will meet required national safety and operational standards
- Safety assessments will be conducted by expert independent consultants
- Hydrogen safety education will be offered to all relevant utility personnel, partners, and first responders
- Testing protocols will incorporate gradual increases in hydrogen blending percentages
- Projects will include continuous project monitoring through SCADA systems
- Teams will conduct regularly scheduled inspections for all project equipment
- Teams will perform regular leakage and pipeline integrity inspections
- Leverage lessons learned from other hydrogen blending pilot programs

SOCALGAS HYDROGEN BLENDING DEMONSTRATIONS

[redacted]

Hydrogen Research Manager

SoCalGas

SoCalGas Project Overview- UC Irvine

- **Purpose**: Provide operational, live blending and system performance data for blending from 5% - 20% hydrogen gas by volume in an isolated portion of a medium pressure steel and plastic distribution pipeline system.

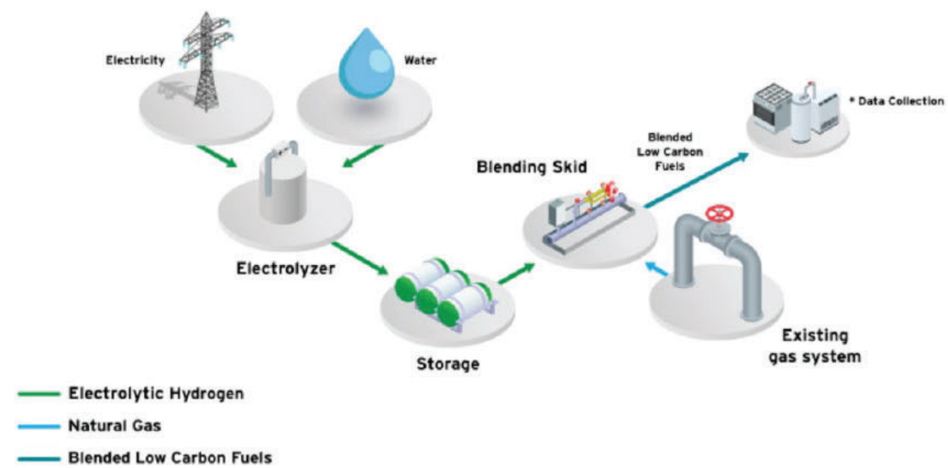
- **Project Components**: H2 will be created and blended onsite utilizing an electrolyzer, blending skid, and non-bulk H2 storage

- **Project Location**: W Peltason Dr., UC Irvine Campus

- **Project Duration**: ~4 years, including a 24-month demonstration period

- **Project Cost**: ~ $14.82 Million

- **Environmental and Community Impact:**
  CalEnviro, percentile: 45



SoCalGas UC Irvine Project Data Collection Plan

- Hydrogen blend volume will be gradually increased over the course of the demonstration through frequent testing of gas quality, leakage, end-use equipment, pipelines, and pipeline components.
  - Prior to injection of hydrogen, all assets will be inspected and leak tested

Data Collection and Analysis:

- Gas Usage Monitoring
- Customer Meter Performance
- Customer Equipment Evaluation & Validation
- Emissions Testing and Measurement (NOx)
- Odorant Sampling
- Leak Surveys and Associated Equipment
- Material Compatibility Verification
- Blending Skid Operation

SoCalGas Proposed Project Overview - Open System (Up to 5%)

- **Background:** *"The UC Riverside Study finds that the literature review supports hydrogen blends up to five percent, in that these relatively low concentrations may be injected without significantly increasing risk factors to storage and transmission with no modification, or only minor modification, to the existing natural gas system." (D.22-12-057 p 16-17)*
- **Purpose**: provide operational, live blending and system performance data for blending up to 5% hydrogen gas by volume in an open portion of a medium pressure distribution pipeline system.
- **Project Components**: TBD
- **Project Location**: TBD
- **Project Duration**: ~4 years
- **Project Cost**: TBD
- **Environmental and Community Impact:** Location TBD

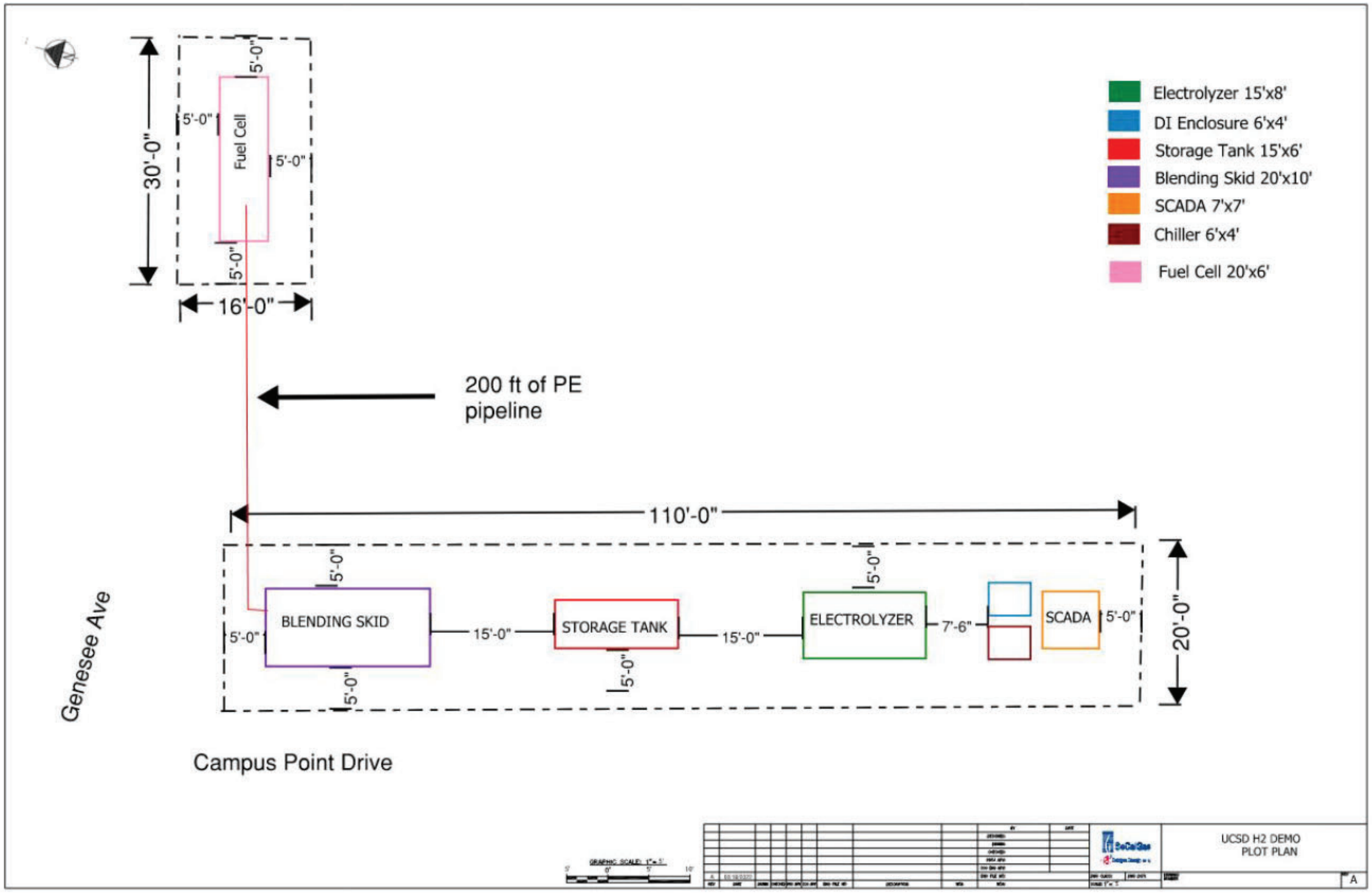
SDG&E Hydrogen Blending Demonstration at UC San Diego

Pooyan Kabir, PhD
Senior Hydrogen Engineer
SDG&E

SDG&E Project Overview- UC San Diego

- **Description:** Study the impact of hydrogen blending from 5-20% in a closed loop, low pressure (~25 psi) modern polyethylene distribution pipeline. Blended gas will be used to power a fuel cell and would engage UC San Diego's Center for Energy Research.
- **Project Components:**
  - Electrolyzer
  - Hydrogen storage ~<10 kg
  - Blending skid
  - Solid Oxide Fuel cell
  - Polyethylene pipe (new)
- **Project Duration:** ~ 4.5 years, including a 24-month demonstration and testing period.
- **Project Cost Estimate:** ~ $13.9 Million
- **Project Location:** UCSD Campus parking lot, Southeast of Genesse Ave and Campus Point Dr., in La Jolla, San Diego.
- **Environmental and Community Impacts:** CalEnviroScreen Score for project location is 25 percentile. Anticipate significant campus collaboration; no CARB permits required for fuel cell.

Project Layout Drawing



SDG&E Project Equipment and Testing Plan

Electrolyzer	Properties	Unit
Power Requirement	236	kVA
Hydrogen Production Rate	65	kg/day
Water Consumption	7.1	gallon/hr
Delivery Pressure to H2 Storage	435	psig

Hydrogen Storage	Properties	Unit
Storage Tanks	1	Units
Storage Pressure	435	psig
Hydrogen Storage Weight	10	kg/tank

% Blending Level	Timeframe
5% to 10 %	Months 1 to 6
10% to15%	Months 7 to 12
15% to 20%	Months 13 to 18

Data Collection and Analysis:

- Monthly Odorant Sampling and Analysis
- Monthly Leak Surveys and leak detection equipment evaluation
- Quarterly maintenance of major equipment (blending skid, electrolyzer)
- Baseline and post-testing pipeline sampling and analysis
- Odorant Compatibility
- Long term integrity modeling
- Co-development of utility blended gas standards for the construction, maintenance, operations of hydrogen blended natural gas system

Southwest Gas Hydrogen Blending Demonstration

Ariana Frame

Distribution Engineer

Southwest Gas Corporation

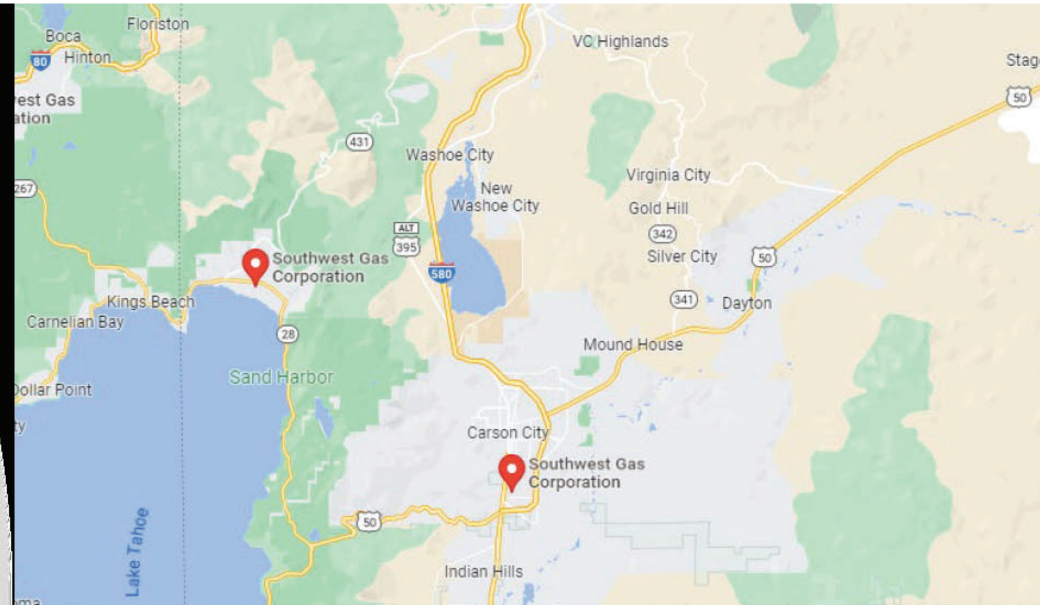
SOUTHWEST GAS CORPORATION

SWG Project Overview

- **Description:** Collect complimentary data to develop a hydrogen blending standard for the state of California by generating and blending H2 gas in a closed-loop system operating in California's coldest region.

- **Project Components:**
  - Electrolytic hydrogen generation
  - 5-20% blend study
  - Operating conditions in one of the coldest regions in California
  - Serve 18 customers, including Southwest Gas' own operations building
- **Project Duration:** ~ 4.5 years, including a 21-month demonstration and testing period.
- **Project Cost Estimate:** ~$10.21 million
- **Project Location:** Truckee, CA – Alpine Region
- **Environmental and Community Impacts:** On-going assessment and engagement as project develops. **CalEnviro, percentile: 3**

SOUTHWEST GAS CORPORATION

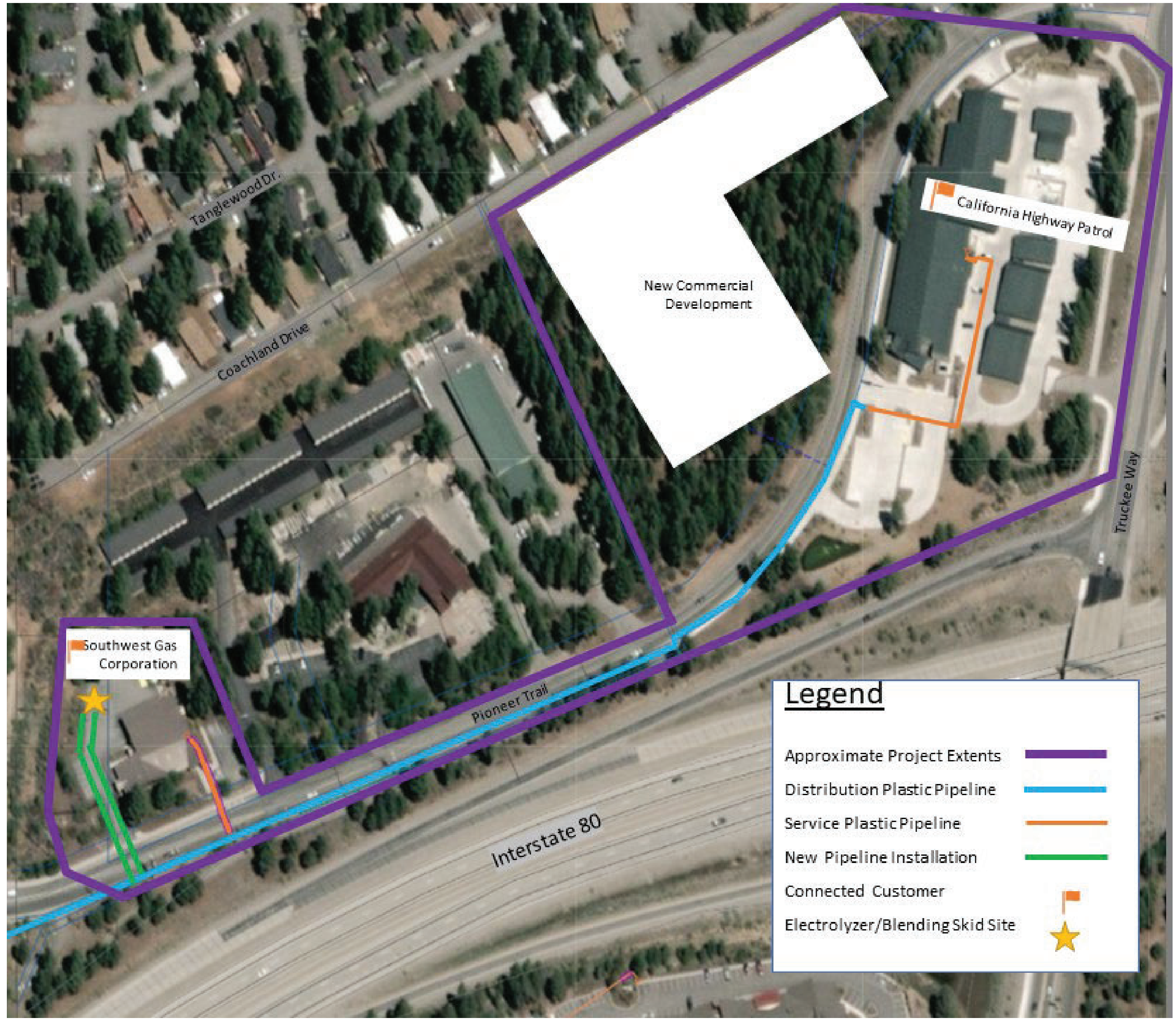


SWG Project Overview

- On-site H_2 generation via electrolyzer
- 1 mile of new plastic pipeline
- 18 customers, including Southwest Gas' own operations building

Collecting hydrogen blending data in this Alpine region of California will be crucial to assessing and developing a well-rounded hydrogen blending injection standard for the state. Having a standard will provide an additional pathway to reducing our carbon footprint.

SOUTHWEST GAS CORPORATION



PG&E'S TRANSMISSION HYDROGEN DEMONSTRATION

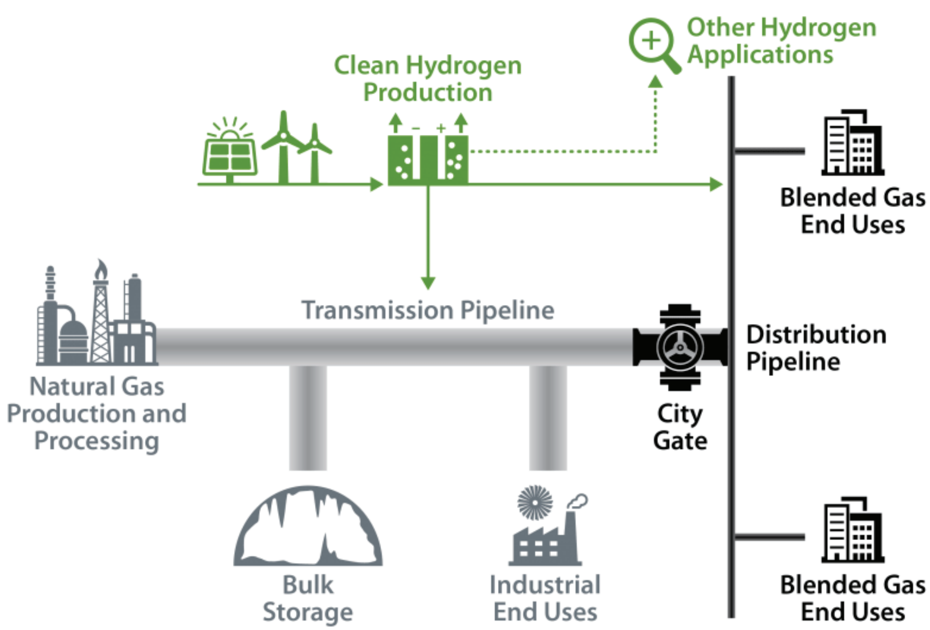
JAMIE RANDOLPH, PRINCIPAL HYDROGEN PROGRAM MANAGER

GHG EMISSIONS STRATEGIES

MAY 16, 2023

Transmission vs. Distribution of Natural Gas

Why are transmission systems different?



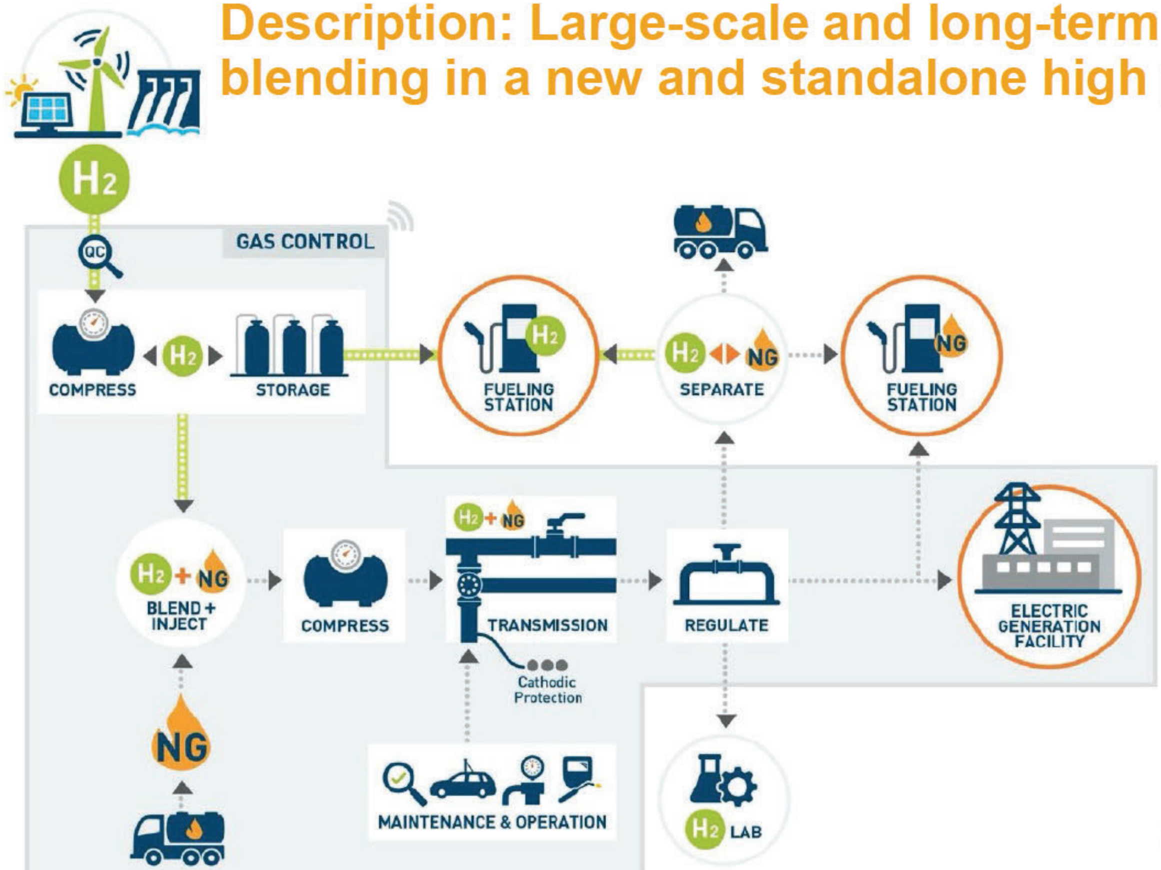
Transmission system
- Mostly steel pipeline
- High pressure (60-1,400 psi)
- Larger-diameter pipe (18-36 inch)
- Regional, longer distance transport across the state

Distribution system
- Extensive polymer pipes with some steel
- Low pressure <60 psi
- Smaller-diameter pipelines
- Serve local communities

Image Credit: HyBlend: Opportunities for Hydrogen Blending in Natural Gas Pipelines | Department of Energy

PG&E Project Overview

Description: Large-scale and long-term demonstration of Hydrogen blending in a new and standalone high pressure gas transmission system



Project Components:

- Hydrogen production by Northern California Power Agency (NCPA)
- Full-scale stand-alone, new transmission system
- 5-30% blend study
- End-use: NCPA power plant and fueling stations

Project Duration: 10+ years

Project Cost Estimate: ~$330 million

Project Location: Lodi, CA

Environmental and Community Impacts:

- CalEnviroScreen 81%
- Job creation
  - Construction (temporary jobs): 200 – 300
  - Facility staffing and operations: 50 – 100

Safety Driven Solution

Large-scale and long-term demonstration of Hydrogen blending in a **new and standalone** high pressure **gas transmission system**

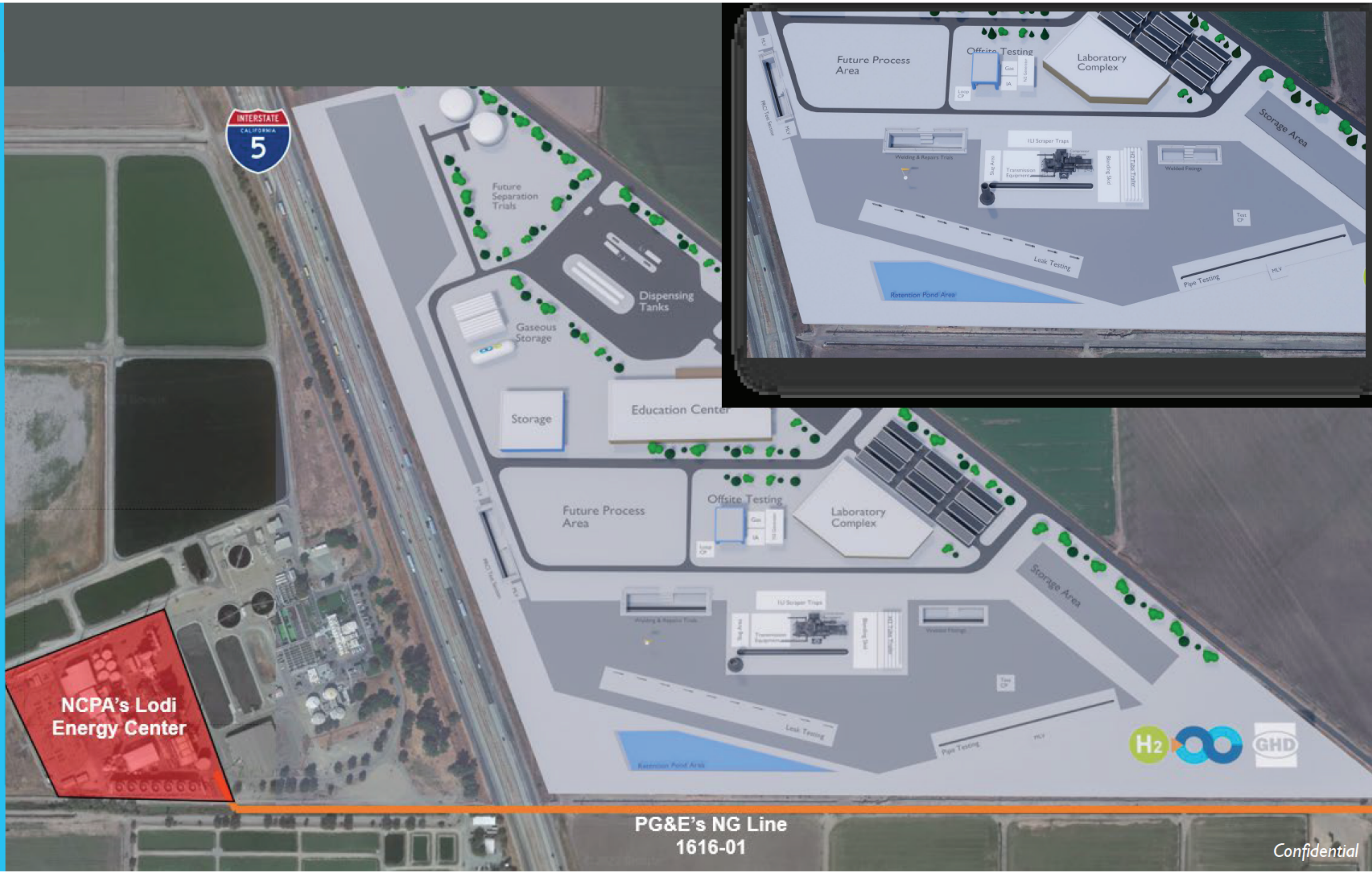
Operations and Maintenance

Integrity

Gas Quality and Measurement

Fluid Hydraulics

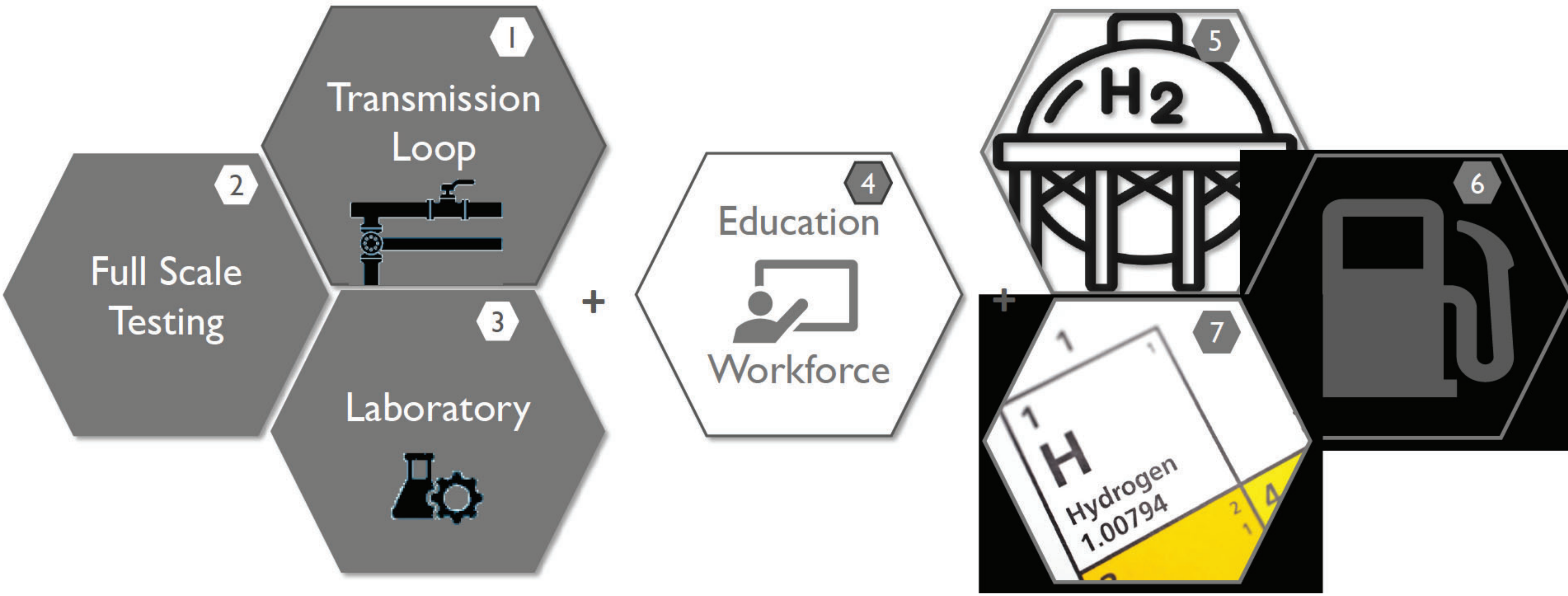
Safety



INTERSTATE
CALIFORNIA
5
Future Separation Trials
Dispensing Tanks
Gaseous Storage
Storage
Education Center
Future Process Area
Offsite Testing
Laboratory Complex
Storage Area
Leak Testing
Pipe Testing
Retention Pond Area
NCPA's Lodi Energy Center
PG&E's NG Line
1616-01
Confidential

Key Project Components

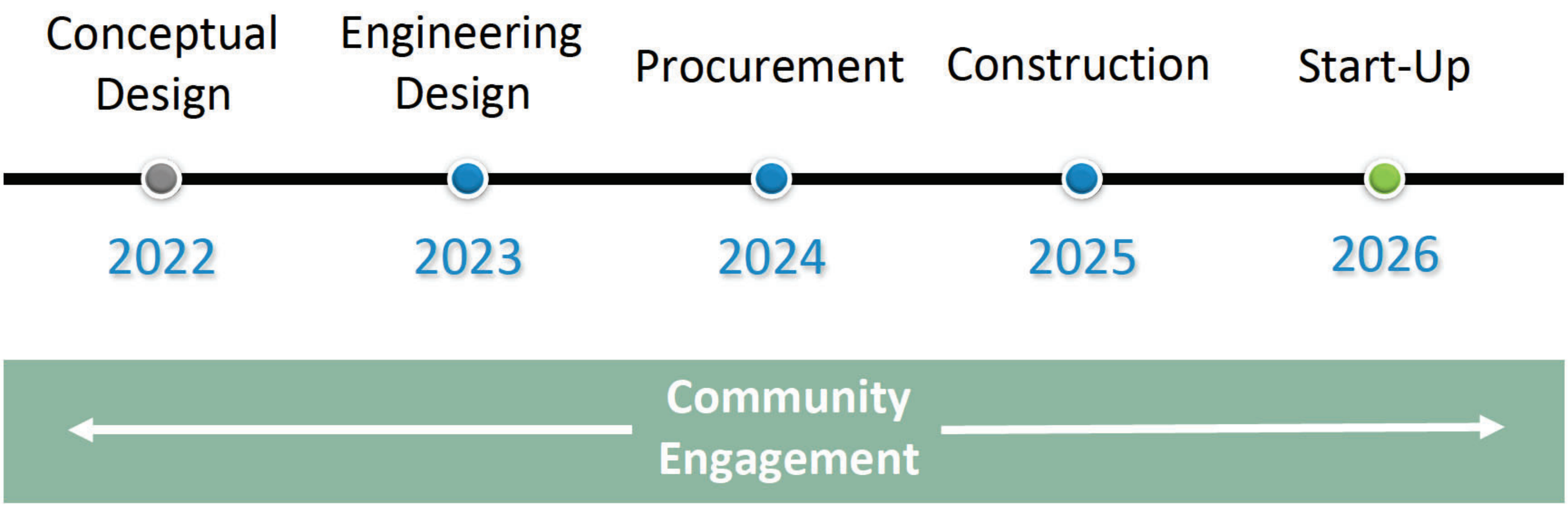
Research & Demonstration + Education & Workforce Development



Project Attributes

Redundancy	0-30% by vol
SAFETY <u>evaluation</u> of pipeline + components	SAFETY <u>protocols</u> at each step
Education & Training	Community Engagement
Industry + public	Continuous

Project Timeline



Preliminary Cost Estimates +/- 30%

Approximate Project Cost by Phase

Phase 1	Phase 1	Phase 1	Phase 2	Phase 2	Phase 2	Phase 3	Phase 3	Phase 3
Transmission Loop	Hydrogen Blending Operations Building	Civil & Site Improvements	Laboratory Buildings + Equipment	Education and Training Buildings	Civil & Site Improvements	Storage and Maintenance	Hydrogen Fueling Station + Storage	Civil and Site Improvements
Phase 1: ~$92 M			**Phase 2: ~$170 M**			**Phase 3: ~$65 M**		
Total~$330 M								

Thank You

Jamie Randolph, Hydrogen Program Manager, Principal
hydrogen@pge.com

Pilot Project Summary

Project Title	Live Blending Description	H2 Blends Considered	Pipeline Detail	End Use Equipment Detail	Location & Climate Detail	Project Costs
SoCalGas – UCI H2 Blending Pilot	Isolated portion of distribution system.	Up to 20% by volume	Medium Pressure Distribution Pipeline (Steel and Plastic)	Commercial and Residential	Irvine, CA; Moderate coastal conditions	$14.82 MM
SoCalGas – Open System Blending	“Open” portion of distribution system	Up to 5% by volume	TBD	Commercial and Residential	TBD	TBD
SDG&E – UCSD H2 Blending Pilot	Isolated portion of distribution system	Up to 20% by volume	Medium Pressure Distribution Pipeline (Polyethylene Pipe)	Fuel cell	La Jolla, CA; Moderate coastal conditions	$13.9 MM
Southwest Gas H2 Blending Pilot	Isolated portion of distribution system	Up to 20% by volume	Medium Pressure Distribution Pipeline (Polyethylene Pipe)	Commercial	Truckee, CA; Extremely cold weather conditions, high elevation	$10.21 MM
PG&E	Isolated, standalone, and new transmission system	Up to 30% by volume	High pressure (steel)	Power Plant and Fueling Station	City of Lodi, CA; Mediterranean climate	$90-330 M

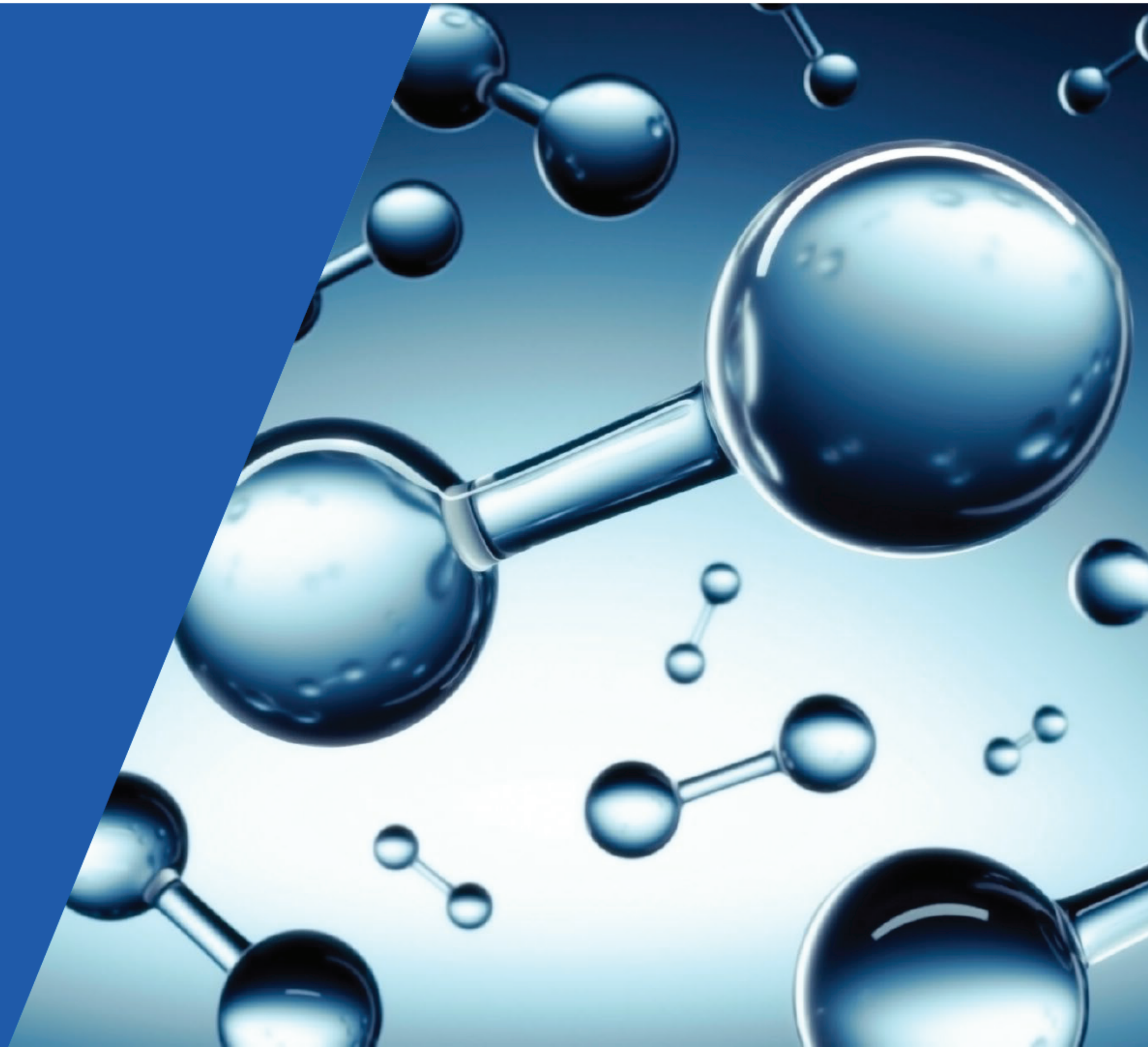
ATCO™

FORT SASKATCHEWAN H_2 BLENDING PROJECT

ALBERTA, CANADA

STAKEHOLDER WORKSHOP: JOINT UTILITIES H_2 BLENDING AND INJECTION PILOTS FOR CALIFORNIA

JUNE 13, 2023

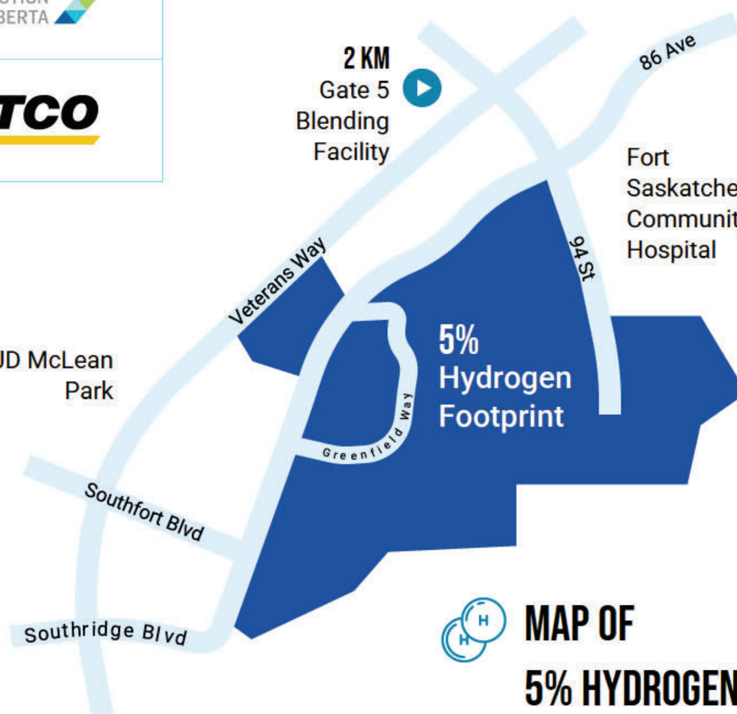


FORT SASKATCHEWAN HYDROGEN BLENDING

COMMISSIONED IN FALL 2022

2,100 ATCO customers became the first in Alberta to use a **5%** hydrogen/natural gas blend

Mostly residential homes	Some small businesses	One school

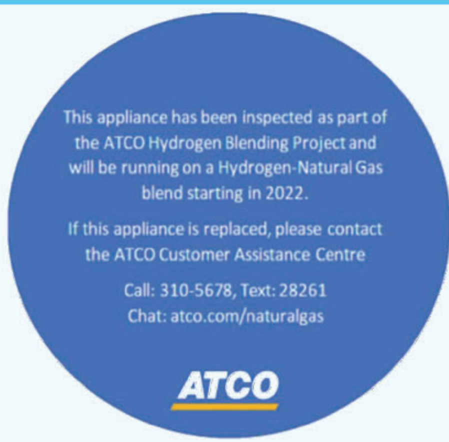


MAP OF 5% HYDROGEN BLENDING PROJECT

CUSTOMER ENGAGEMENT & APPLIANCE INSPECTIONS

ATCO has engaged with customers through:

- Open Houses
- Community Events
- **Hydrogen Blending Home Inspections**



OVER 85% INSPECTION RATE

Almost 1,800 customers

Over 5,800 appliances inspected

HOW WILL THIS IMPACT HOMES AND BUSINESSES?

Combusting 5-20% blended natural gas does not result in any noticeable change to the look, sound or smell

Extensive research and testing has found that **hydrogen blends up to 20% do not impact** typical appliances or system and customer materials

WILL HYDROGEN BE SAFE?

Just like with natural gas, **hydrogen can be produced, transported, stored and used safely**

Both natural gas and hydrogen must be treated with respect and with proper care and handling

ATCO's standards and processes will be updated to ensure that **ATCO maintains the level of safety** that our customers and the public experience today

At 20% hydrogen blends, the production of **Carbon Monoxide (CO) is reduced**

HYDROGEN SYSTEMS CAN BE **AS SAFE, OR SAFER** THAN NATURAL GAS SYSTEMS

WINTER DEMONSTRATIONS

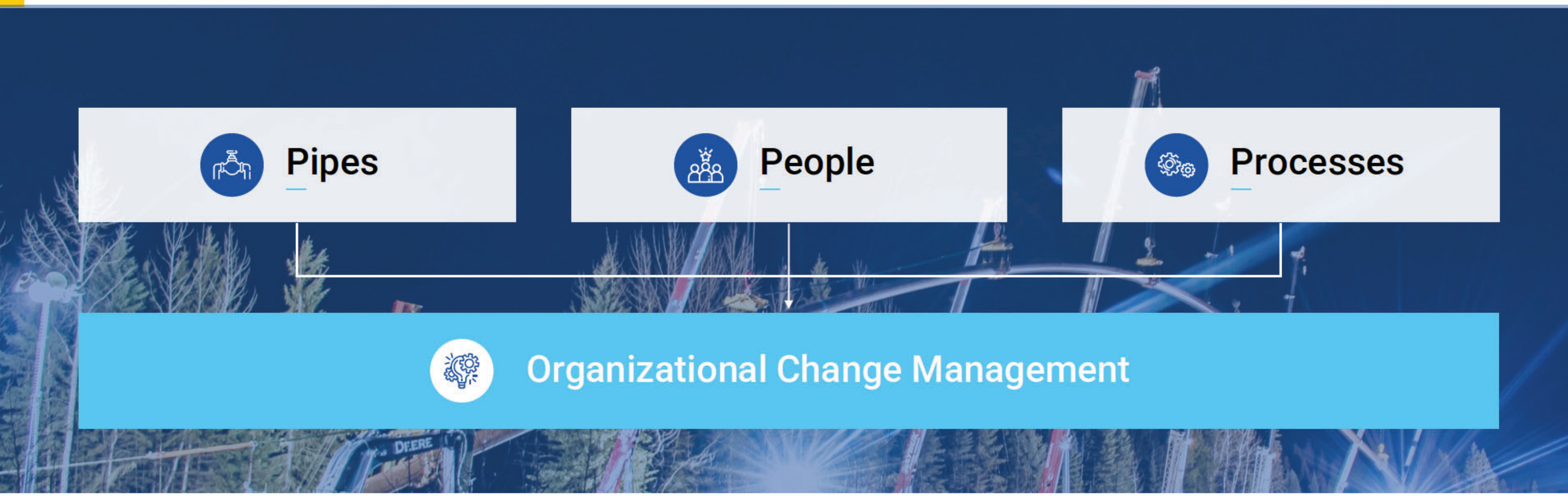
Edmonton Home Pilot Projects

UP TO
22%

hydrogen blend

January - September 2022

ORGANIZATIONAL CHANGE MANAGEMENT



- Modifications to existing practices & procedures, or
- Confirmation something doesn't need to change

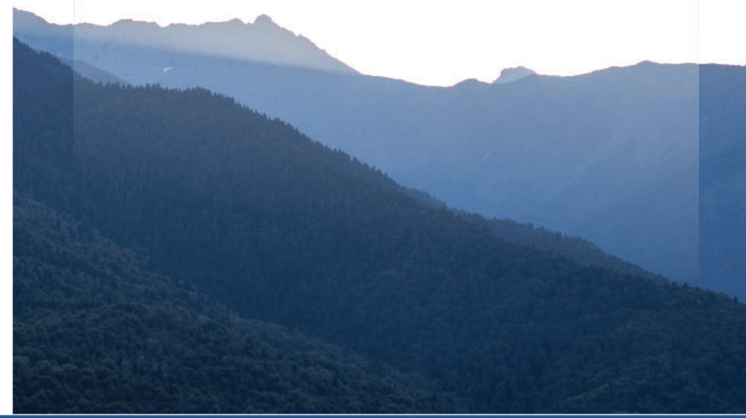
- New tools, equipment, training
- Customer engagement & education programs

TECHNICAL CHALLENGES & INTERNATIONAL COLLABORATION

In order to adapt our business and ensure the safety of our customers, ATCO has partnered with several institutions and organizations worldwide for:

- Hydrogen blending facility design
- Material impact assessments
- Appliance testing
- Leak detection
- Odorant effectiveness
- Gas stratification
- Risk assessments

wood.
blacklinesafety
UNIVERSITY OF CALGARY
C-FER Technologies
A SUBSIDIARY OF ALBERTA INNOVATES
DNV
Dynamic Risk
Northern Gas Networks
THE UNIVERSITY OF CALIFORNIA IRVINE



APPLIANCE TESTING PROGRAM

THREE SCENARIOS TESTED ON 13 COMMON APPLIANCES:

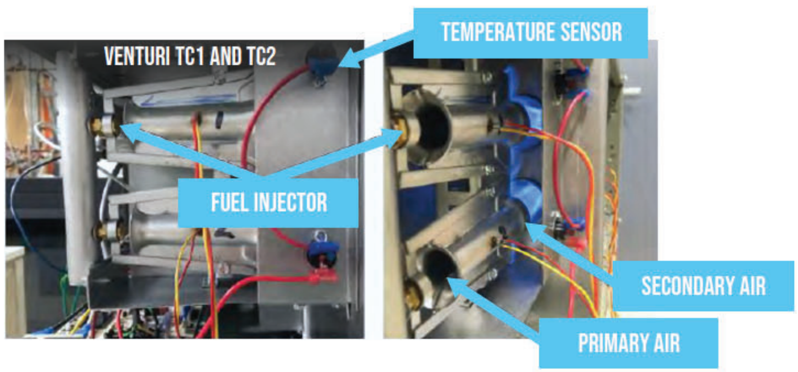
01
Steady-state conditions

02
Fast/abrupt changes in hydrogen

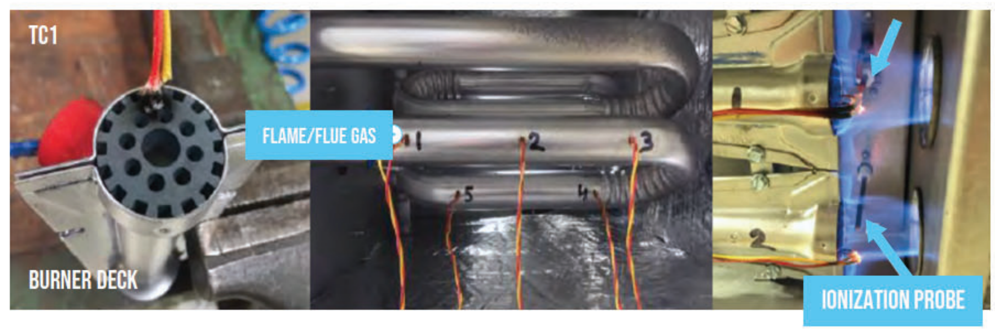
03
Cold start and reignition with high percentages

EACH TEST MEASURED:

- Burner deck temperatures
- Occurrence of flashback
- H_2, O_2, NO_X, CO emissions
- Radiation flux
- Flame detection system operation
- Visual observations of flame structure



Thermocouples placed on the Venturi (Left) and the flame that stabilizes on the burner deck



Thermocouples placed on the burner deck (Left) and heat exchanger (Middle) and flame image (Right).

APPLIANCE TESTING

There are no impacts to appliances at our planned **5% and 20% blend rates** including:

- no change or reduction in NOx
- reduction in CO

ACCEPTABLE H_2 %

20 - 30%	25%	30%	40%
• Hot water heater (conventional) • Unit heater	Infrared heater	• Range/oven • Barbeque • Hot water heater (on-demand) • Furnace • Clothes dryer	Fireplace

MATERIAL IMPACT ASSESSMENT

A full review of **materials used in ATCO's and customer's systems in Fort Saskatchewan** has been completed to determine suitability for hydrogen blends

- All materials suitable for use in **natural gas service** are suitable for use **hydrogen blended service**
- Similar materials have been used for decades within other jurisdictions

The Alberta distribution system is primarily polyethylene which is compatible with hydrogen

Pressures downstream of house regulators are so low that hydrogen embrittlement is not a concern

LEAKS

If a low-pressure system is **gas tight**, it is also **hydrogen tight**

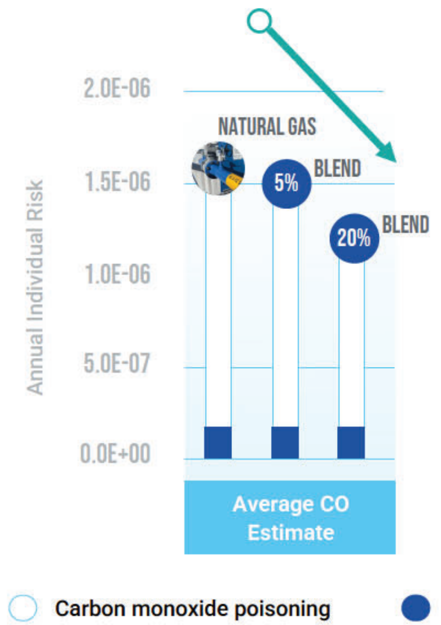
Hydrogen is over **7 times lighter** than natural gas and will diffuse much more rapidly

Just like natural gas, **hydrogen can be:**

- odorized
- detected using leak detection technologies

RISK ASSESSMENT – FIRE, EXPLOSION AND CARBON MONOXIDE

Decreasing overall risk inversely proportional to % H_2 blend



Based on evidence from Hy4Heat, hydrogen systems can be modified or designed for purpose to have similar fire and explosion risk to natural gas systems

CARBON MONOXIDE

related risk accounts for up to **95%** of overall risk and is **reduced with blending** and **eliminated with 100% H_2**

HYDROGEN SAFETY SUMMARY

HYDROGEN SYSTEMS CAN BE **AS SAFE, OR SAFER** THAN NATURAL GAS SYSTEMS

There are **no impacts** to gas appliances with up to **20% hydrogen**

If a low-pressure system is **gas tight**, it is also **hydrogen tight**

Existing odourants remain effective with hydrogen and hydrogen blends

Distribution system materials are suitable for 20% hydrogen

Pressures are low such that hydrogen embrittlement is not a concern

System capacity and PE lifespan are not meaningfully impacted

Hydrogen systems can be modified or designed for purpose to have similar fire and explosion risk to natural gas systems

Carbon monoxide accounts for up to 95% of overall risk and is reduced with blending and eliminated with 100% hydrogen

ATCO™

HAVE MORE QUESTIONS?

Email them to h2@atco.com

WANT TO LEARN MORE?

CHECK OUT ATCO'S HYDROGEN WEBPAGE

GAS.ATCO.COM/HYDROGEN.HTML

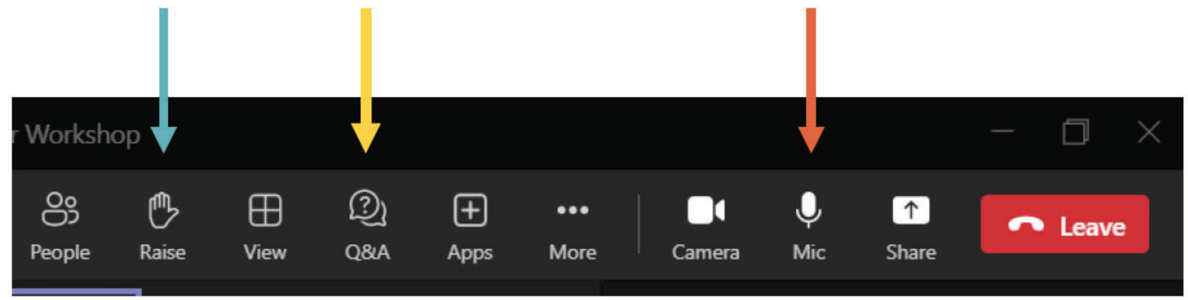
ATCO™

THANK YOU

HYDROGEN – THE NATURAL NEXT STEP

Stakeholder Questions and Comments

Feedback Instructions



- There are two ways to submit questions:
  - via the **Q&A function** — Can be submitted any time during workshop
  - via the **Raise [Hand] function** — Will only be "called on" during Feedback Session, from 2:45-3:30.

Please include your name and your organization's name before providing questions or feedback

Feedback Instructions & Reminders

Questions and comments focused on the following are not included in the scope and will not be addressed by the presenters on this workshop:

- The merits of hydrogen in comparison to other technologies
- The cost of hydrogen versus other fuels or technologies
- The merits of a “gas decarbonization” versus “electrification” strategy for California
- The merits of blending hydrogen into the existing natural gas pipeline vs. 100% dedicated hydrogen pipelines

Stakeholder Questions and Comments

Thank You

Name	Question	Response
Bill Leighty (Guest)	Bill Leighty, The Leighty Foundation, Juneau, AK May we repurpose extant NatGas pipelines for safe, profitable, long-term GH2 service ? Chris San Marchi, SNL, reports that only 1% H2 blended in NatGas reduces fracture toughness of the pipeline steel by ~ 2/3. Does this mean that for safe, profitable, long-term GH2 service the pipeline total pressure and pressure fluctuations must be severely limited, perhaps at unacceptable value cost ratio? San Marchi also avers we must know "the condition of the asset ..." (weld hard spots, pipe steel flaws, physical damage or stress ...) to consider GH2 service. How can we do that ? Or, does this mean that all NatGas pipelines must be declared useful only as "conduits" for hosting novel "pull-in rehab" linepipe highly resistant to HE, HCC with very low thru-wall GH2 permeation ? Who is working on this question ? Thank you.	These are the types of questions we are hoping to learn more about through projects such as PG&E's H2 Infinity demonstration. We anticipate the project will provide operational data to help determine whether we can safely repurpose existing natural gas transmission infrastructure for hydrogen blending and if modifications (such as reducing pressure, using special coatings, upgrading compressors, etc.) are needed. The results from the "Hydrogen Blending into Natural Gas Pipeline Infrastructure Review of the State of Technology" (Oct 2022) report provide valuable insights into how material properties may change under the presence of hydrogen in a controlled laboratory environment. The operational data from this full-scale demonstration will fill critical knowledge gaps (such as weather and temperature induced changes, pressure cycling, length of exposure, effect of natural gas components and contaminants, etc.)[1] and further the scientific understanding of material impacts in a long-term operational environment. Although we hope the H2 Infinity demonstration will provide additional insight regarding the value cost ratio and profitability of natural gas/hydrogen pipelines, this question is out of scope of this project. https //docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF
Beth Kelly	Will leakage be monitored for safety AND environmental impact? (Smaller leak may not meet "safety" levels, but will have impact on environmental impact.	We will implement the best available technologies for monitoring hydrogen-natural gas blends at the time of project implementation. We are working with technology experts within natural gas and hydrogen to keep up to date with sensor and technology development so that we are considering best available by the time our projects are ready for deployment.
Joon Seong	Does SoCalGas and the other utilities involved in the blending pilot projects have details available for leakage detection (e.g., technical specifications, detection threshold, etc.)?	We do not have these details at this time. We will implement the best available technologies for monitoring hydrogen-natural gas blends at the time of project implementation. We are working with technology experts within natural gas and hydrogen to keep up to date with sensor and technology development so that we are considering best available by the time our projects are ready for deployment. We are also open to feedback and suggestions that any of our project stakeholders have for appropriate technologies we should consider.
Beth Kelly	Dr. Raju mentioned knowledge gaps - have the utilities identified knowledge gaps and identified how each project would inform/fill in the knowledge gaps? Will identification of knowledge gaps be part of the stakeholder process?	The utilities have been working together to identify hydrogen blending knowledge gaps for the last several years. The utilities hosted their first workshop on this topic on May 24, 2019 and again on August 20, 2019. The utilities also lean on available literature such as the UC Riverside study for knowledge gap identification. We are also open to hearing stakeholder feedback on hydrogen blending knowledge gaps that stakeholders recommend for our consideration.
Sara Gersen	How did the Edmonton demonstrations impact NOx emissions from residential appliances? And what adjustments did you do to the residential appliances, if any?	A comprehensive appliance testing program was undertaken by ATCO for common gas appliances found within Fort Saskatchewan. All appliance tests measured emissions, including CO and NOx. Overall, NOx emissions with increasing hydrogen blend percentage were found to not meaningfully change. However, in some cases a reduction in NOx was measured. In the case of the furnace, the change in NOx emissions at the planned blend rates of up to 20% were not meaningful. At higher blend rates, a reduction in NOx can be observed. In the case of the water heater, a similar trend was found
Etienne (Guest)	Are you sure that H2 can be odorized? Is there not a risk that the H2 can leak whicle the much larger molecules that cause the odor will not?	SoCalGas has experience with successfully odorizing blended gas with up to 20% hydrogen at the [H2] Innovation Experience demonstration facility in which hydrogen is blended with pipeline natural gas on site to fuel several natural gas appliances. There are also several test cases, including ATCO's live blending demonstration project in Fort Saskatchewan and their prior research indicating that existing odorants remain effective with hydrogen blends.

Amended Hydrogen Blending Demonstration Application (A.22-09-006)
Sierra Club DR-04

Attachment 18

From: [redacted]
To:
Subject: FW: Response to Question at "Southern California Gas Company, San Diego Gas & Electric Company, Southwest Gas Corporation, and Pacific Gas and Electric Company Hydrogen Blending Pilot Project Stakeholder Workshop #2 – Technical Workshop"
Date: Thursday, April 4, 2024 11:36:26 AM

[redacted]

From: [redacted]
Sent: Monday, November 20, 2023 3:48 PM
To: [redacted]
Subject: FW: Response to Question at "Southern California Gas Company, San Diego Gas & Electric Company, Southwest Gas Corporation, and Pacific Gas and Electric Company Hydrogen Blending Pilot Project Stakeholder Workshop #2 – Technical Workshop"

fya

From: [redacted]
Sent: Monday, November 20, 2023 6:48 AM
To: 'Jeanne Baran' <JBaran@cityofirvine.org>
Cc: Kev Abazajian <KAbazajian@cityofirvine.org>
Subject: RE: Response to Question at "Southern California Gas Company, San Diego Gas & Electric Company, Southwest Gas Corporation, and Pacific Gas and Electric Company Hydrogen Blending Pilot Project Stakeholder Workshop #2 – Technical Workshop"

Good Morning Jeanne,

You're very welcome. Yes, we'd very much appreciate having a follow-up discussion with Councilmember Agran. Please don't hesitate to reach out if you have any follow up questions.

Have a great week and Happy Thanksgiving too!

[redacted]
Public Affairs Manager
[redacted]
1919 S State College Blvd. Anaheim, CA 92806

Glad to be of service®

From: Jeanne Baran <JBaran@cityofirvine.org>
Sent: Saturday, November 18, 2023 12:59 PM
To: [redacted]
Cc: Kev Abazajian <KAbazajian@cityofirvine.org>
Subject: [EXTERNAL] RE: Response to Question at "Southern California Gas Company, San Diego Gas & Electric Company, Southwest Gas Corporation, and Pacific Gas and Electric Company Hydrogen Blending Pilot Project Stakeholder Workshop #2 – Technical Workshop"

CAUTION! EXTERNAL SENDER STOP, ASSESS, AND VERIFY

Do you know this person? Were you expecting this email, any links or attachments? Does the content make sense? If suspicious, do not click links, open attachments, or provide credentials. Don't delete it. **Report it by using the REPORT SPAM option!**

Hi [redacted],

Thank you. We appreciate you providing detailed and constructive answers to Kev's questions and will share the information with Councilmember Agran. We may want to schedule a follow-up discussion at some point.

Again, thank you for the thorough response, and I wish you a Happy Thanksgiving Holiday.
Jeanne

Jeanne Baran | Senior Council Executive Assistant
(949) 724-6226 | jbaran@cityofirvine.org | Website [theofficeofcouncilmemberlarryagran.org] **| FB** [facebook.com]

From: [redacted]
Sent: Friday, November 17, 2023 5:22 PM
To: Kev Abazajian <KAbazajian@cityofirvine.org>
Cc: kevork@uci.edu; Jeanne Baran <JBaran@cityofirvine.org>
Subject: Response to Question at "Southern California Gas Company, San Diego Gas & Electric Company, Southwest Gas Corporation, and Pacific Gas and Electric Company Hydrogen Blending Pilot Project Stakeholder Workshop #2 – Technical Workshop"

CAUTION: EXTERNAL EMAIL

Good Afternoon Dr. Abazajian,

Thank you for participating in the recent Joint Utilities Hydrogen Blending Technical workshop. Your question was referred to SoCalGas and as the city of Irvine's representative, I'll be glad to respond to your questions. Please see responses below.

Why not host this experiment at an isolated building or housing demonstration facility with no residents?

- Multiple hydrogen demonstration projects have been successfully conducted on the University of California, Irvine campus since 2014, including collaborating with SoCalGas on the first successful blending of hydrogen into natural gas infrastructure in the United States in 2016 [news.uci.edu], which used a hydrogen blend to power UCI's power plant.

- The California Public Utilities Commission (CPUC), at the recommendation of a University of California, Riverside-commissioned study, directed SoCalGas and other utilities to propose *real-world* hydrogen blending demonstration projects to inform a statewide injection standard.

- According to the CPUC, "The UC Riverside Study finds that before a hydrogen injection standard can be safely established for California's common carrier pipeline system, a fuller understanding of real-world safety and operational impacts is desirable. Pilot projects and further study can help the development of the clean renewable hydrogen market, enable a variety of use cases, and contribute to achieving California's climate goals."

- Creating a statewide blending standard is an important step in the process to allow for the delivery of clean, renewable hydrogen to California. Blending demonstration projects such as these can provide a real-world catalyst for the production of clean, renewable hydrogen across California and support Governor Newsom's Hydrogen Market Development Strategy by helping to lower costs as the market for California hydrogen scales. Blending is a safe and reliable process that has been utilized around the world for decades and supports California's ambitious clean energy goals.

Why does this experiment have to be done at a university campus?

- The University of California, Irvine has been a national pioneer in researching the potential of hydrogen in a clean energy economy thanks to work from its Advanced Power and Energy Program. The skills, expertise and experience working directly with SoCalGas on hydrogen-related projects over the past decade makes this a logical collaboration.

- This project will help us answer key questions about how hydrogen performs in existing infrastructure and appliances and how clean fuels like green hydrogen could be delivered in California's existing gas system, either to customers already connected to the gas grid, or to generate clean electricity in zero-emissions fuel cells.

Why is any increased risk to a university campus tolerable when these tests can be done in isolation from a residential and educational environment?

- According to the U.S. Department of Energy [eere.energy.gov], "Hydrogen is no more or less dangerous than other flammable fuels, including gasoline and natural gas."

- In addition, hydrogen blending is not a new technology and hydrogen has been safely and reliably utilized around the world for decades. Hawai'i Gas has been using hydrogen in its fuel mix for a half-century. Today, it has more than 1,100 miles of pipelines that transport up to 15 percent hydrogen, serving homes, restaurants, and businesses. Other countries with hydrogen blending projects [nrel.gov] up to a 30% blend include Belgium, Canada, Denmark, France, Germany, Italy and the United Kingdom.

- According to the University of California, Riverside study, blending up to 20% hydrogen "has been studied and demonstrated in a limited fashion throughout the world without significant incidents." That study helped inform the CPUC's decision to direct California gas utilities, including SoCalGas to propose live hydrogen blending demonstration projects.

- If the proposed project at UCI is selected, SoCalGas intends to employ extensive safety measures before, during, and after the proposed experiment that would include:
  - Providing hydrogen safety education and training for personnel
  - Conducting safety assessments for hydrogen storage and hydrogen components
  - Offering surveys of end-use customer equipment to confirm behind-the-meter equipment is operational and free of leaks
  - Installing methane/hydrogen alarm systems where indoor equipment is housed
  - Implementing regular leak surveys before, during and after the experiment
  - Creating hydrogen blending specific customer protocols and emergency response plans
  - Conducting gas system operational tests and equipment tests.

If you have any follow up inquiries, please reach out to me. My contact information is attached.

Thank you,

[redacted]
Public Affairs Manager
[redacted]
1919 S State College Blvd. Anaheim, CA 92806

Glad to be of service®

From: Kev Abazajian <KAbazajian@cityofirvine.org>
Sent: Monday, November 6, 2023 3:18 PM
To: hydrogen [redacted]
Cc: kevork@uci.edu; Jeanne Baran <JBaran@cityofirvine.org>
Subject: [EXTERNAL] Question at "Southern California Gas Company, San Diego Gas & Electric Company, Southwest Gas Corporation, and Pacific Gas and Electric Company Hydrogen Blending Pilot Project Stakeholder Workshop #2 – Technical Workshop"

Dear Hydrogen Folks at SDG&E and PGE,

Than you for hosting the "Southern California Gas Company, San Diego Gas & Electric Company, Southwest Gas Corporation, and Pacific Gas and Electric Company Hydrogen Blending Pilot Project Stakeholder Workshop #2 – Technical Workshop," today. I tried to ask this question at the workshop and was told it was "beyond the scope of the experts on this panel." Note that this panel included the following people: Ariana Frame, Arun Satheesh Kumar Raju, Lily Backer, William Buttner, Tyler Collins, Melanie Davidson, Jack Brouwer, Pooyan Kabir, Danielle Mark, Kevin Pease, Jamie Randolph, Moriah Saldana, Chris San Marchi, Kevin Simmons, Vince McDonnell, Blayne Waymire, and Yan Zhao.

Given the background and expertise of these numerous folks, especially their background in proposing to put this pilot experiment on university campuses, I would expect them to have a clear answer on a health, safety, and experimental design question that is certainly a technical matter, and an important one at that.

Nonetheless, maybe the people above do, in fact, not have that expertise, and you can help me find who does and who can affirmatively answer my questions. The questions are the following:

- Why not host this experiment at an isolated building or housing demonstration facility with no residents?
- Why does this experiment have to be done at a university campus?
- Why is any increased risk to a university campus tolerable when these tests can be done in isolation from a residential and educational environment?

Thank you for your time, and I look forward to your detailed response.

Sincerely,

Dr. Kev Abazajian
Vice Chair, City of Irvine Sustainability Commission and Professor of Physics and Astronomy, UC Irvine

---

This email originated outside of Sempra. Be cautious of attachments, web links, or requests for information.

Amended Hydrogen Blending Demonstration Application (A.22-09-006)
Sierra Club DR-04

Attachment 22.b

ORANGE COVE HYDROGEN BLENDING

August 4, 2023

[redacted] – Engineering Hydrogen Manager
[redacted] – Hydrogen Engineering Team Lead

SoCalGas™

HYDROGEN 101 OVERVIEW – WHAT IS HYDROGEN?

- Most abundant element in the universe and 3rd most abundant on the Earth's surface after Oxygen & Silicon
- Nontoxic and nonpoisonous
- When combusted, hydrogen produces only water vapor, and it has been blended into existing gas infrastructure to help decarbonize pipelines by a variety of localities.
- Hydrogen has unique characteristics like any other fuel.

SoCalGas

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HYDROGEN 101 OVERVIEW – WHAT INDUSTRIES USE HYDROGEN?

- Agricultural/Chemical
  - Used to produce ammonia (NH3) which is an important part of fertilizers and refrigerant
- Petroleum Refining
  - Hydrocracking, Hydrotreating
- Iron and Steel
  - Metals Treatment
- Food Processing
  - Turn unsaturated fats into to saturated oils and fats
- Transportation

Why Study Hydrogen Blending: The Opportunities

Enhance California's clean energy economy & resiliency.

Demonstrate safety in infrastructure and appliances.

A 20% clean H_2 blend in a SCG-like system = removing CO2 from 1M passenger vehicles for a year.

Maintain energy reliability and affordability for Californians.

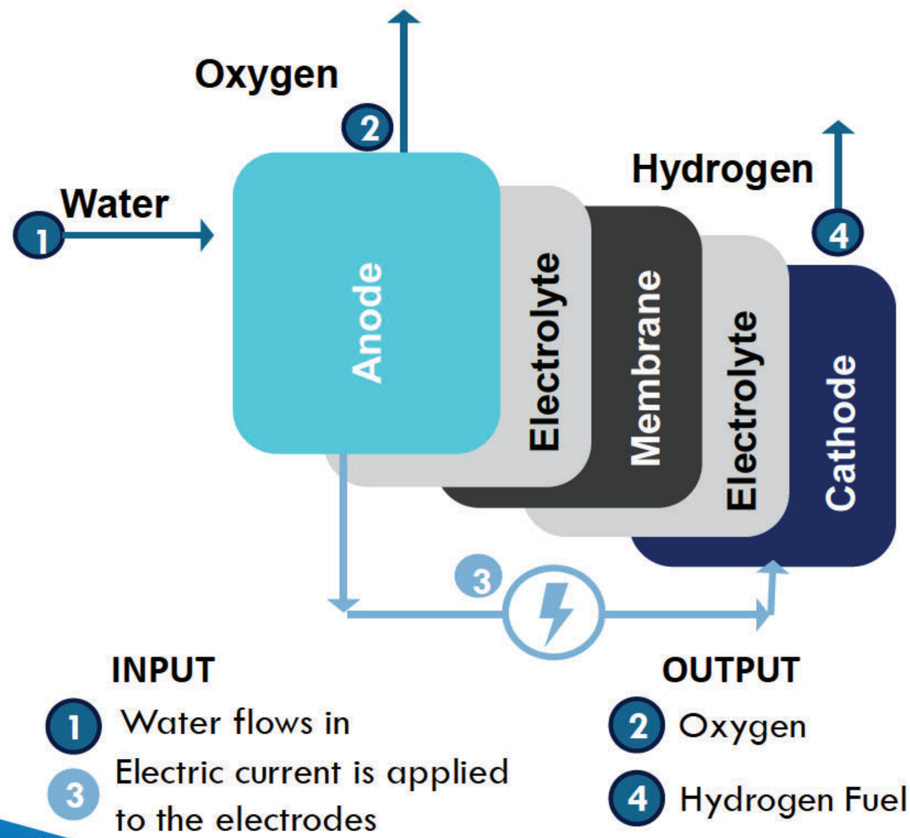
Reduce hydrogen costs through production & delivery at-scale.

Foster a just transition for energy workers.

SoCalGas

Glad to be of service.®

HYDROGEN 101 – HOW HYDROGEN IS FORMED VIA ELECTROLYSIS



- Water (H_2O) is put into the system
- Electric current applied to the H_2O causes it to break down into its components: Hydrogen (H_2) & Oxygen (O)
- Hydrogen moves across a membrane to be collected while Oxygen leaves the system

HYDROGEN BLENDING THROUGHOUT THE GLOBE

Company	Location	H_2 %Blend	Start Year	Comments
ATCO	Western Australia	10%	2022	Operational: blended into the existing natural gas distribution network within the City of Cockburn, involving around 2,700 connections
SNAM	Italy	5 & 10%	2019	Complete: blended into the existing natural gas transmission network to two industrial companies in the area, a pasta factory and a mineral waters bottling company
Cadent – HyDeploy	United Kingdom	20%	2019 - 2021	Complete: blended into the existing natural gas distribution network. Phase 1, 100 homes; private university network (20 building). Phase 2, 10-month trial; 668 homes + church, school, and businesses; public network
ENGIE – GRHYD	France	20%	2014	Complete: blended into the existing natural gas distribution network of a new neighborhood and an NGV refueling station for buses located in the Dunkirk Urban Community.
AGIG- HyP SA project	Tonsley, South Australia	5%	2021	Operational: blended into the existing natural gas distribution network of about 4000 homes, businesses and schools and 100% to industry via tube trailers
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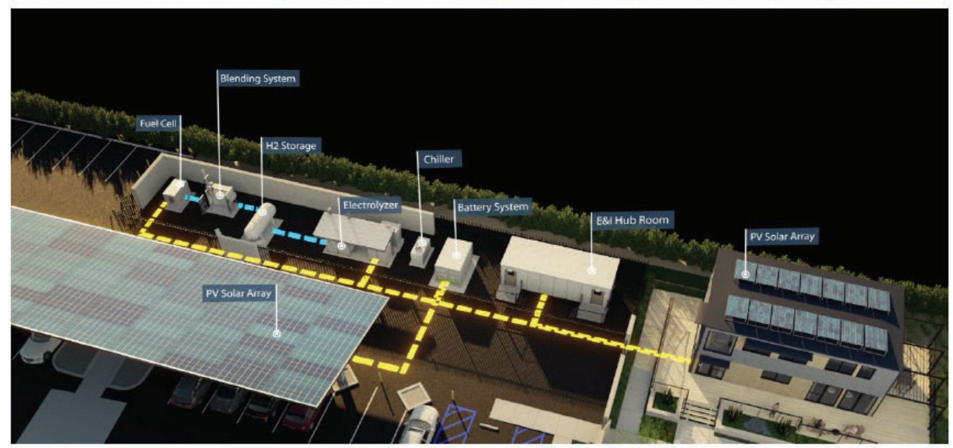
AGIG- HyP Murray Valley	Wodonga, Victoria, Australia	10%	2023	Construction: blend into the existing natural gas distribution network of 10 MW electrolyer, 40,000 Homes, 20 Industrial Site, >85k People.
Netze BW (EBKG.DE) - Hydrogen Island Hringen	Oehringen, Germany	30%	2022	Operational: blended into the existing natural gas distribution network of an area in a town near Heilbronn with detached family homes

HYDROGEN BLENDING DEMONSTRATIONS THROUGHOUT NORTH AMERICA

Company	Location	H2 %Blend	Start Year	Comments
New Jersey Resources	New Jersey	<1%	2021	Operational: Blend into 8“, 60 psig pipeline; 65 kg/day; 175 kW Electrolyzer
CenterPoint Energy	Minnesota	Up to 5%	2021	Operational: 1 MW Electrolyzer, up to 432 kg-H2/day
Enbridge Gas	Ontario, Canada	Up to 2%	2021	Operational: 3,600 homes and businesses; up to 1,000 kg-H2/day
Dominion Energy	Utah & North Carolina	5%	2021	Operational: H2 blending in the company's Training Site
ATCO Gas	Alberta, Canada	5%	Fall 2022	In Planning: About 2,000 customers
Southwest Gas	Arizona & Nevada	Up to 20%	2022	In Planning: Training site
National Grid New York	New York	Up to 3%	2022-2025	In Planning: Heat approximately 800 homes and fuel 10 municipal vehicles
New Mexico Gas Co.	New Mexico	TBD	2022	In Planning: Phase 1 in the Training site; Phase 2 in a small segment of the distribution system that serves customers

[H2] INNOVATION EXPERIENCE

- State-of-the-art demonstration project designed to show the resiliency and reliability of a hydrogen microgrid at our ERC facility in Downey, CA
- Features solar panels, a battery, an electrolyzer to convert solar energy to hydrogen, and a fuel cell to supply electricity for the home
- Hydrogen is blended up to 20% with natural gas and used in the home's tank-less water heater, clothes dryer, gas stove, fireplaces and BBQ grill
  - All the appliances have been unmodified and are functional at the 20% blended gas



Appendix

Regulatory Updates

» Biomethane OIR Decision (D.22-15-057)

- Requirement to conduct stakeholder outreach and incorporate stakeholder input into pilot project design
  - Joint utility stakeholder workshop held on June 13th
- Propose demonstrations evaluating hydrogen blending between 0.1 and 5% in an open portion of the distribution system
  - Current scope of projects at all three IOUs is to study blends at 5%-20% in isolated system segments

» Hydrogen Blending Application

- Joint applicants and PG&E are directed to meet and confer to coordinate a comprehensive joint amended application
- Schedule of proceeding is stayed for one year or until amended application is submitted

» Expected Fling Schedule- Q4 2023

Joint IOU H2 Blending Application

Utility	Pilot Location	Material	Blend %	End Use	Notes
SoCalGas	UC Irvine	Mixed (Steel & Plastic),Distribution	5-20%	Campus Buildings TBD	Isolated pipeline system, Coastal climate
SoCalGas	TBD	TBD- mostly Polyethylene plastic (PE), Distribution	0.1-5%	All customers in selected Pressure District	Blend into an "open portion" of SoCalGas distribution system
SDG&E	UC San Diego	Polyethylene plastic (PE), Distribution	5-20%	UCSD Fuel Cell System	Isolated pipeline system, Coastal Climate
Southwest Gas	Truckee, CA	Polyethylene plastic (PE), Distribution	5-20%	Select end users in Truckee	Isolated pipeline system, High elevation and extreme cold conditions
PG&E	Lodi, CA	Steel, Transmission	5-30%	Lodi Energy Center	Isolated transmission level blending, hydrogen and NG fueling, various test scenarios

HYDROGEN BLENDING DEMONSTRATION PROJECT

Orange Cove City Council Meeting

November 8, 2023

SoCalGas

SoCalGas

Proud History of Delivering Energy to Southern California

OVER 150 YEARS

of institutional knowledge and expertise

Service territory covers about

24,000 SQUARE MILES

of diverse terrain throughout Central and Southern California, from Visalia to the Mexican border

Largest natural gas distribution utility in country[1], powering Southern California with increasingly clean, safe and reliable energy delivered to more than

21+ MILLION CUSTOMERS

[1] based on number of customers and revenue

SoCalGas

WHAT IS HYDROGEN?

- Hydrogen is a gaseous fuel that can be produced by splitting water into hydrogen and oxygen using electricity sourced from renewables like solar.
- When combusted, hydrogen does not produce carbon emissions.
- Small percentages of hydrogen can be blended with natural gas to reduce carbon emissions.

Glad to be of service.®

SoCalGas™

WHY STUDY HYDROGEN BLENDING: THE OPPORTUNITIES

Enhance California's clean energy economy & resiliency.

A 20% clean H_2 blend in a SoCalGas-like system = removing CO2 from 1M passenger vehicles for a year.

Reduce hydrogen costs through production & delivery at-scale.

Demonstrate safety in infrastructure and appliances.

Maintain energy reliability and affordability for Californians.

Maintains and grows skilled jobs.

HYDROGEN BLENDING THROUGHOUT NORTH AMERICA

Company	Location	H2 %Blend	Start Year	Comments
New Jersey Resources	New Jersey	<1%	2021	Operational: Blend into 8", 60 psig pipeline; 65 kg/day; 175 kW Electrolyzer
CenterPoint Energy	Minnesota	Up to 5%	2021	Operational: 1 MW Electrolyzer, up to 432 kg-H2/day
Enbridge Gas	Ontario, Canada	Up to 2%	2021	Operational: 3,600 homes and businesses; up to 1,000 kg-H2/day
Dominion Energy	Utah & North Carolina	5%	2021	Operational: H2 blending in the company's Training Site
ATCO Gas	Alberta, Canada	5%	Fall 2022	In Planning: About 2,000 customers
Southwest Gas	Arizona & Nevada	Up to 20%	2022	In Planning: Training site
National Grid New York	New York	Up to 3%	2022-2025	In Planning: Heat approximately 800 homes and fuel 10 municipal vehicles
New Mexico Gas Co.	New Mexico	TBD	2022	In Planning: Phase 1 in the Training site; Phase 2 in a small segment of the distribution system that serves customers

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    - Standard appliances have been unmodified and are functional at the 20% blended gas

DEMONSTRATION PROJECTS

Hydrogen Blending Application

- SoCalGas, SDG&E, Southwest Gas and PG&E are proposing hydrogen blending demonstration projects
- Demonstrations will inform the creation of a state-wide hydrogen blending standard for California
- SoCalGas plans to blend up to 5% hydrogen into the natural gas system
- Stakeholder input will inform the pilot project design
- Expected filing in December 2023
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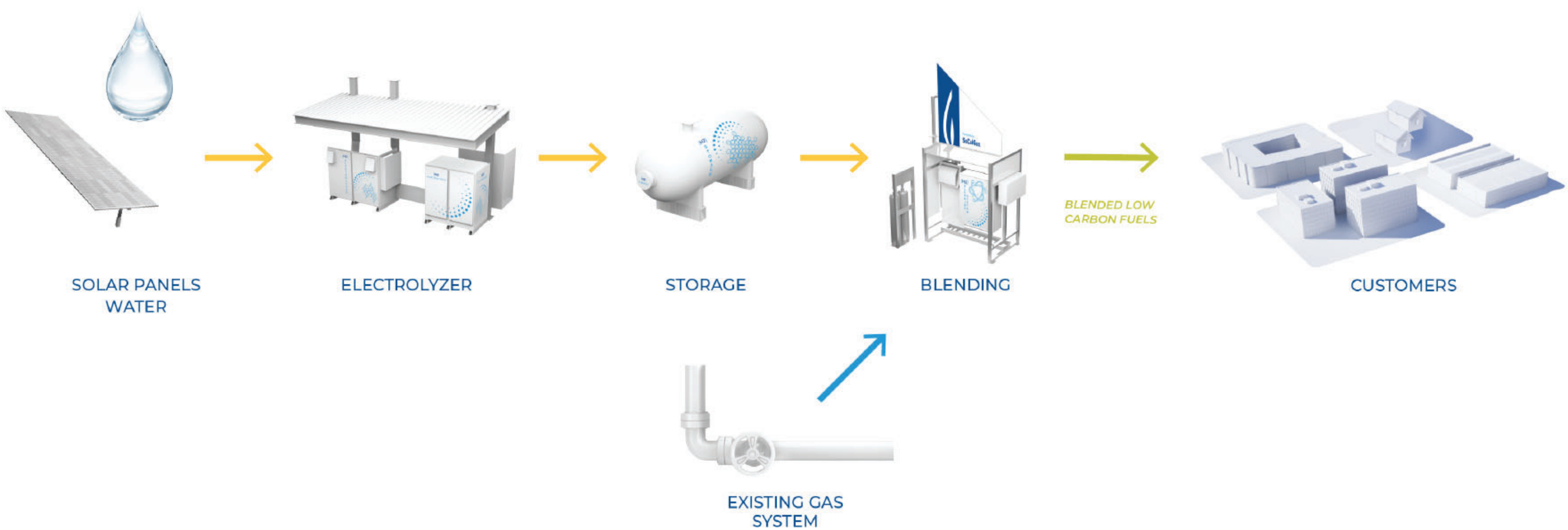
- Construction and project duration estimated 2025 – 2028

SoCalGas

H2/NG BLENDING PROCESS OVERVIEW



COMMUNITY ENGAGEMENT

- SoCalGas' phased approach to the demonstration project includes robust community engagement throughout the process.
- SoCalGas is holding a community meeting at the Orange Cove Community Center on Thurs. Nov. 9 from 6 pm – 8 pm to answer questions and solicit input from the community.
- SoCalGas will return to provide another presentation and gather community input when a decision is made by the CPUC and it has more detailed information about the demonstration project and safety plan.
- Comment cards are available. You may also send us your feedback via email at projectinfo@socalgas.com or by contacting us at 844-765-9385.

Contact:

[redacted]

Public Affairs Manager

[redacted]

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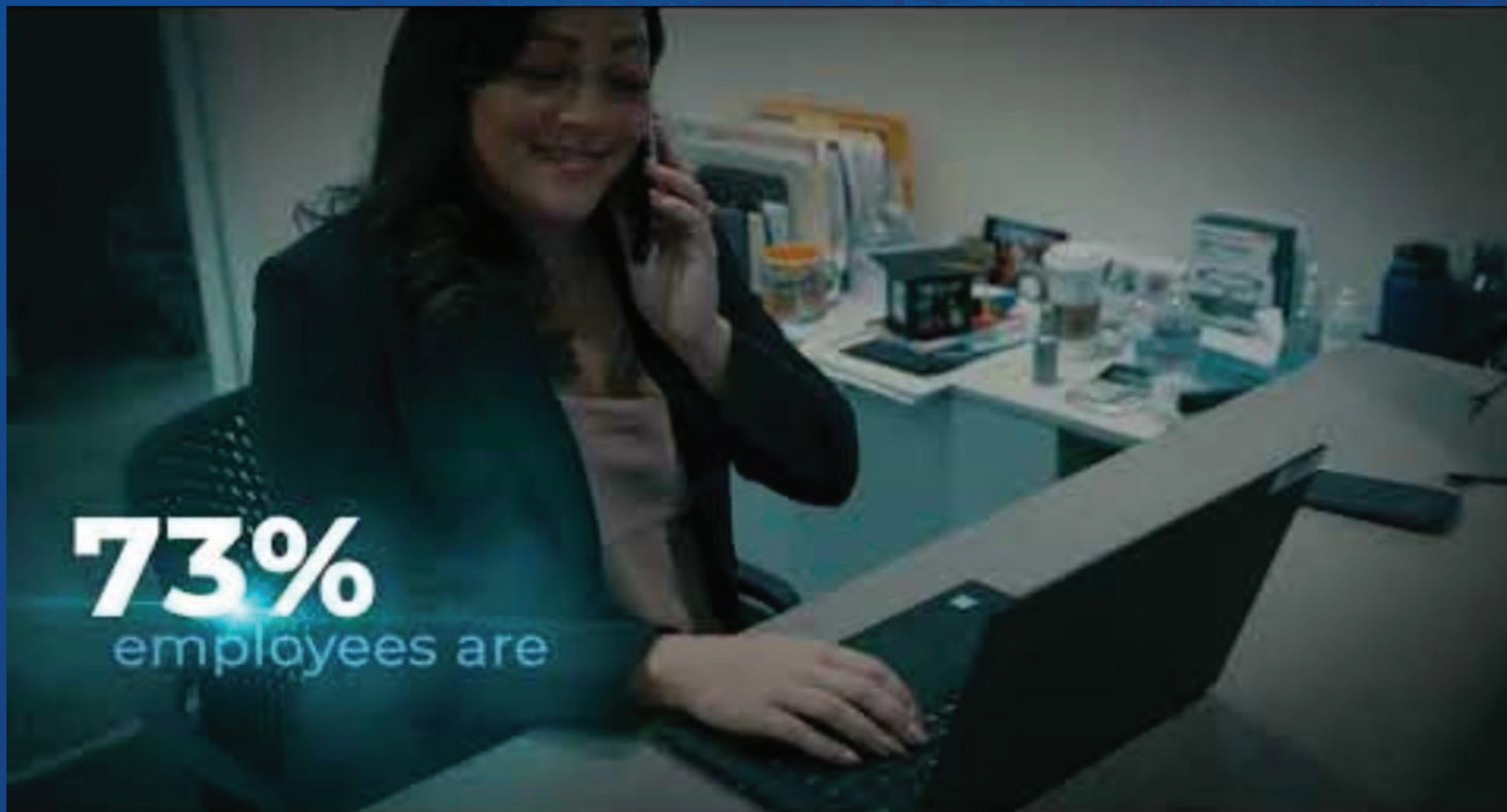
SoCalGas

Appendix

Joint IOU H2 Blending Application

Utility	Pilot Location	Blend %	End Use
SoCalGas	UC Irvine	5-20%	Select campus building
SoCalGas	Orange Cove (under consideration)	0.1-5%	All customers in selected community
SDG&E	UC San Diego	5-20%	UCSD Fuel Cell System
Southwest Gas	Truckee, CA	5-20%	Select end users in Truckee
PG&E	Lodi, CA	5-30%	Lodi Energy Center

SHAPING THE FUTURE



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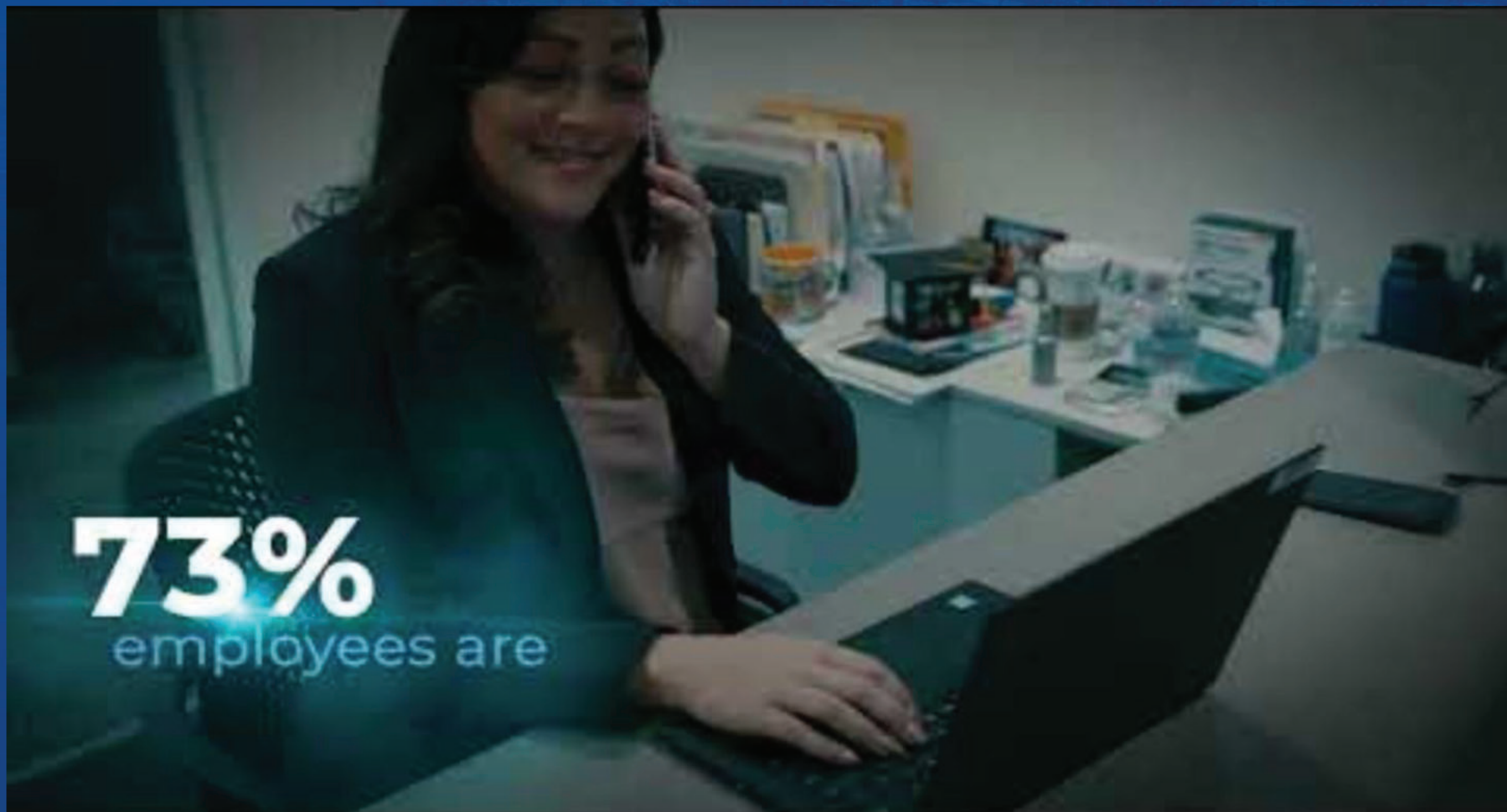

FORMANDO EL FUTURO

[redacted]

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SoCalGas

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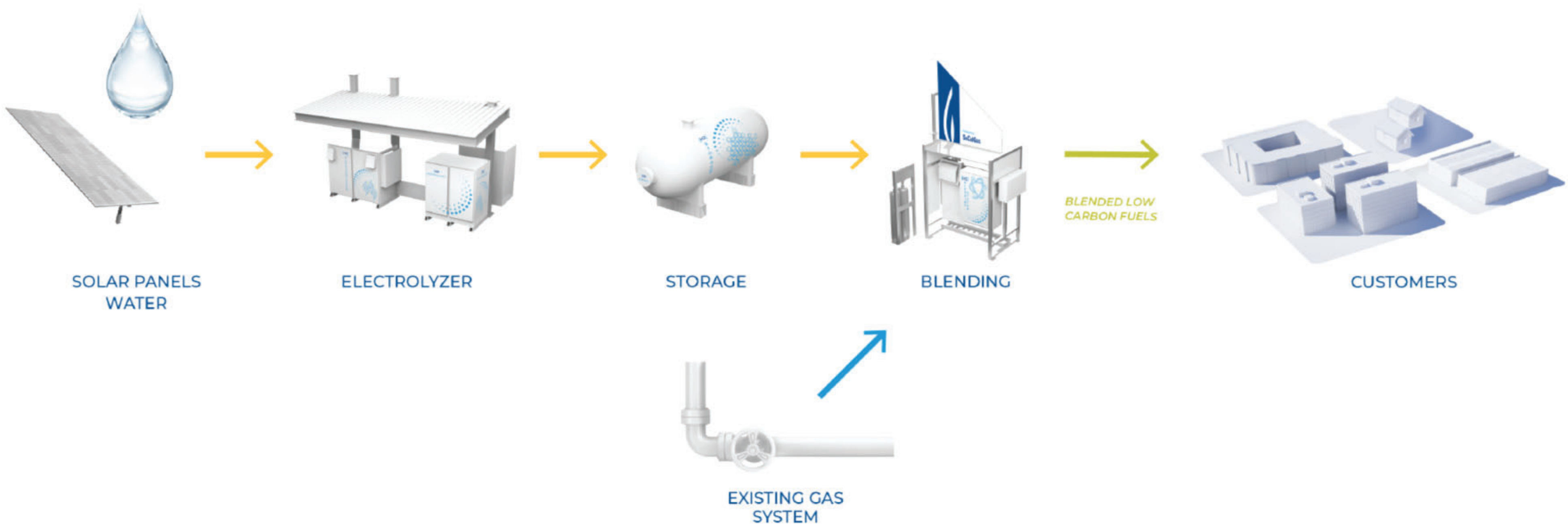

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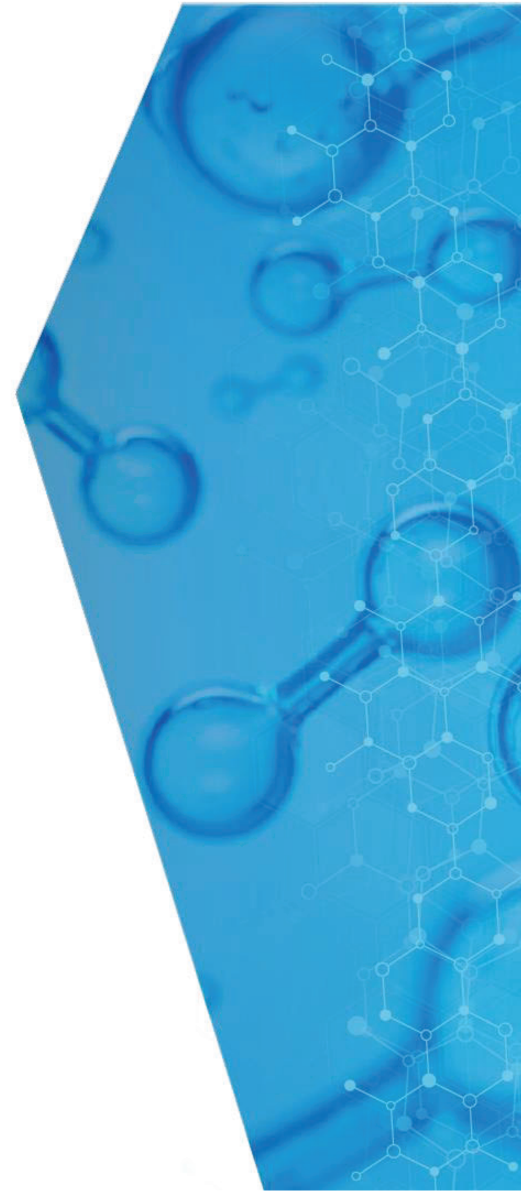

Contact:

[redacted]

Public Affairs Manager

[redacted]

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SoCalGas

Appendix

SAFETY

- Safety is foundational to everything we do at SoCalGas
- Hydrogen blending has been safely used around the world for decades
- The California Public Utilities Commission (CPUC) would like to develop a statewide standard for hydrogen blending
- A study commissioned by the CPUC found that up to a 5% hydrogen blend can be safely blended into the natural gas infrastructure
- For Hydrogen Blending Demonstrations, SoCalGas will deploy enhanced and extensive safety measures

HOW HYDROGEN IS FORMED VIA ELECTROLYSIS

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SoCalGas™

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PG&E	Lodi, CA	5-30%	Lodi Energy Center

City of Orange Cove

Developing A Clean Fuels Network

SoCalGas

Hydrogen Blending is Key to California's Clean Energy Goals

At the direction of the California Public Utilities Commission, SoCalGas is proposing a local demonstration project that could safely blend up to 5% clean, renewable hydrogen into the natural gas system serving approximately 10,000 residents, along with commercial customers in the City of Orange Cove, in Fresno County.

What is Hydrogen Blending?

It is the process of blending hydrogen into natural gas and injecting it into the natural gas infrastructure.

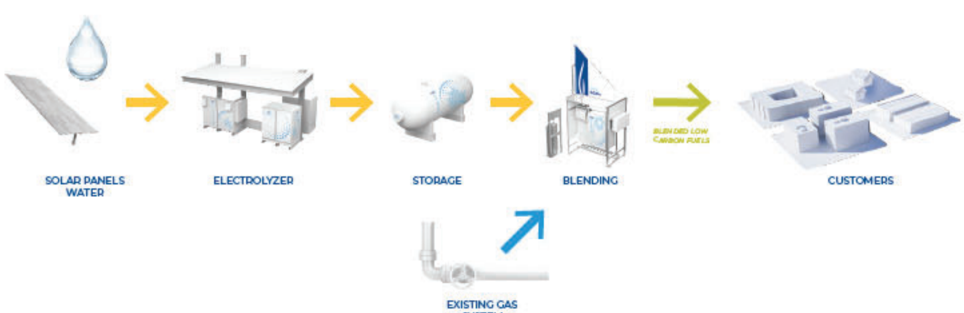
Orange Cove Could Help Pave The Way For A Carbon-Free Future

To support California's climate and clean air goals, SoCalGas is proposing a demonstration project that will blend clean, renewable hydrogen serving residents and businesses. This project would offer a real-world environment to better understand how clean hydrogen and natural gas can be safely delivered to customers in the future. This is part of a broader effort by California and utilities to develop a standard for safe hydrogen blending, which could reduce greenhouse gas emissions and improve air quality. The data gathered from this demonstration can also help assess how to speed the development and deployment of related advanced technologies key to the state's climate and clean air goals.

Proposed Project Overview:

- The project would blend clean, renewable hydrogen with natural gas into the existing gas distribution system serving approximately 10,000 residents, along with commercial customers in the City of Orange Cove
- The project will be located on the southwest corner of Jacobs Avenue and South Avenue
- Starting with small concentrations of 0.1% gradually increasing the hydrogen concentrations up to 5%
- Active blending is expected to last approximately 18 months in the city

How Hydrogen Blending will work in the City Of Orange Cove:

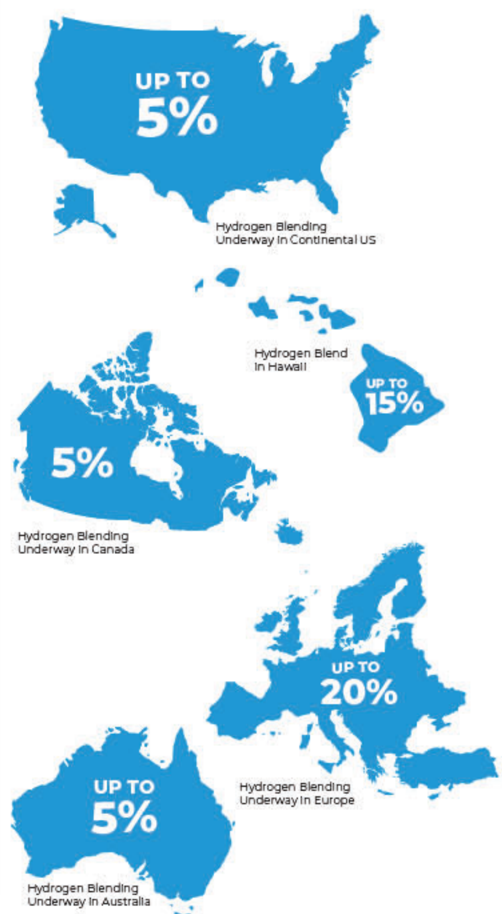


For more information: socalgas.com/H2Blending

Hydrogen Blending is Proven & Safe

Hydrogen is safely and reliably utilized around the world and has been for decades in countries like Belgium, Canada, Denmark, France, Germany, Italy and the United Kingdom. Hawaii Gas has also been using hydrogen in its fuel mix for a half-century.

SoCalGas will employ extensive safety measures that include leak surveys and detection technology, safety assessments of hydrogen storage and components, end-use equipment surveys, education and training.



Amended Hydrogen Blending Demonstration Application (A.22-09-006)
Sierra Club DR-04

Attachment 22.c

From: [redacted]
To: dparra@cityoforangecove.com
Cc: [redacted]
Subject: RE: Touchpoint/Dan
Date: Monday, February 26, 2024 5:10:00 PM
Attachments: Joint Amended Application for H2 Blending Demonstration Projects.docx
Chapter 2 - Technical Presentation - SoCalGas Open System.docx
SCG Hydrogen Blending News Release 3.1.24 FINAL DRAFTv2.docx

Good afternoon Dan,

For your reference, please find attached documents to help you inform the public about the proposed H2 blending demonstration project in Orange Cove. These documents have not been finalized.

Attached:

- Amended Joint Application for H2 blending Pilot Projects
- Technical chapter on open system project (Orange Cove) including project description
- News blog we plan to post on Friday, 3/1

Please let me or [redacted] know if you have any questions.

Thank you,

[redacted]
Media Relations & Strategic Engagement
SoCalGas
[redacted]

-----Original Appointment-----
From: [redacted]
Sent: Wednesday, February 14, 2024 10:04 AM
To: [redacted] Daniel T. Parra
Cc: [redacted]
Subject: Touchpoint/Dan
When: Wednesday, February 21, 2024 2:00 PM-2:30 PM (UTC-08:00) Pacific Time (US & Canada).
Where: Microsoft Teams Meeting

Microsoft Teams meeting

Join on your computer, mobile app or room device

Click here to join the meeting

Meeting ID: 270 793 126 976
Passcode: CQhCqD
Download Teams | Join on the web

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sandiego@m.webex.com
Video Conference ID: 117 487 140 4
Alternate VTC instructions

Or call in (audio only)

+1 858-284-1506,,668853919#   United States, San Diego

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Application of Southern California Gas Company (U 904 G), San Diego Gas & Electric Company (U 902 G), Pacific Gas and Electric Company (U 39 G), and Southwest Gas Corporation (U 905 G) to Establish Hydrogen Blending Demonstration Projects.	A.22-09-006 (Filed September 8, 2022)

JOINT AMENDED APPLICATION OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G), PACIFIC GAS AND ELECTRIC COMPANY (U 39 G), AND SOUTHWEST GAS CORPORATION (U 905 G) TO ESTABLISH HYDROGEN BLENDING DEMONSTRATION PROJECTS

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March 1, 2024

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I. INTRODUCTION

Pursuant to Article 2 of the Rules of Practice and Procedure of the California Public Utilities Commission's (Commission) Decision (D.) 22-12-057[1] issued on December 19, 2022, in Rulemaking (R.) 13-02-008 (Biomethane Rulemaking), and Assigned Commissioner's Scoping Memorandum and Ruling issued on March 3, 2023, Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), and Southwest Gas Corporation (Southwest Gas) (collectively, the Joint Utilities) respectfully submit this Amended Application to establish live hydrogen blending demonstration projects by each utility (the Project(s)).[2]

In D.21-07-005, the Commission dismissed without prejudice Application (A.) 20-11-004, a prior hydrogen blending demonstration program application, and ordered that a future application would need to meet six separate requirements.[3] On September 8, 2022, SoCalGas, SDG&E, and Southwest Gas filed A.22-09-006 initiating the instant proceeding. Three months later, in the Biomethane Rulemaking, the Commission issued D.22-12-057 ordering the Joint

[1] This Amended Application is also intended to follow the guidance under D.21-07-005 issued on July 15, 2021, in A.20-11-004.
[2] Pursuant to Rule 1.8(d) of the Commission's Rules of Practice and Procedure, SoCalGas has been authorized to submit this Application on behalf of the Joint Utilities.
3 D.21-07-005 at 23-26.

Utilities to either amend or file a new application within two years "proposing pilot programs to test hydrogen blending in natural gas at concentrations above the existing trigger level…"[4] The Commission also imposed twelve additional requirements for these pilot programs.[5]

Relying on University of California (UC) Riverside's 2022 Hydrogen Blending Impacts Study (UC Riverside Study) it sponsored, the Commission acknowledged that "…hydrogen blending can be an important decarbonization strategy for the energy and transportation sectors."[6] Further, the UC Riverside Study states in its recommendation that "…it is critical to conduct real world demonstration of hydrogen blending under safe and controlled conditions."[7] Underscoring the importance of projects exploring hydrogen blending, the Commission further noted that the UC Riverside Study outlined "thoughtful and prudent next steps before establishing a system wide injection standard."[8]

In preparing the Projects proposed in this Amended Application, the Joint Utilities complied with the Commission's requirements in D.22-12-057 and the guidance in D.21-07-005. The Joint Utilities seek to examine the efficacy of blended hydrogen as an energy source, develop data to support a safe hydrogen injection standard, and obtain Commission authorization to establish Hydrogen Blending Demonstration Project Balancing Accounts (HBDPBA) for each utility to record their respective incremental costs.

As detailed in the prepared direct testimony, the proposed Projects will consist of live hydrogen blending in the Joint Utilities' distribution and transmission systems to answer technical, operational, and safety questions that cannot be addressed by literature reviews or bench research alone. Because safety, system integrity, operability, and reliability are core concerns for the Joint Utilities, the Projects are a necessary step to formulating California's hydrogen injection standard and corresponding tariff changes. The Joint Utilities' phased approach will study live hydrogen blending in distribution and transmission systems with blends between 0.1% and 20% to inform a future injection standard. Project results may be able to support an interim preliminary hydrogen blending standard.

Based on this Amended Application and the supporting testimony, the Joint Utilities

4 D.22-12-057, OP 7 at 68-69.
5 *Id*., OP 7 at 68-70.
6 *Id*., Finding of Fact (FOF) 17 at 56.
7 UC Riverside, *Hydrogen Blending Impacts Study* (July 2022); *available at* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.
8 *Id*., FOF 19 at 57.

request authority to implement the Projects and to establish proposed cost recovery mechanisms.

II. PROCEDURAL BACKGROUND

A. Biomethane Rulemaking and SRGI Tariff

On February 13, 2013, the Commission initiated the Biomethane Rulemaking with the intent of adopting standards and requirements for biomethane, pipeline open access rules, and related enforcement provisions. On July 5, 2018, the Assigned Commissioner issued a scoping memo ordering the Joint Utilities to jointly file a proposed standard biomethane interconnection tariff and pro forma agreement forms within 90 days. On August 22, 2019, the Assigned Commissioner extended the deadline for filing the proposed standard biomethane interconnection tariff to November 1, 2019. The Assigned Commissioner also directed that the tariff be designated as the Standard Renewable Gas Interconnection Tariff (referred to herein as the SRGI Tariff), because of the likelihood that the Commission would permit other renewable gases besides biomethane to be included in pipeline gas.

On November 1, 2019, the Joint Utilities filed a proposed SRGI Tariff.

On November 21, 2019, Commissioner Clifford Rechtschaffen issued the Phase 4 Ruling to address (1) standards for injection of renewable hydrogen gas into gas pipelines, and (2) implementation of Senate Bill (SB) 1440. Commissioner Rechtschaffen also ordered the Joint Utilities to submit within twelve months an application addressing the following proposed additions or revisions to the SRGI Tariff: (a) A definition of renewable hydrogen for purposes of the SRGI Tariff; (b) a preliminary renewable hydrogen injection standard; (c) any modification to the hydrogen standard for biomethane; and (d) any modifications to the interconnection protocols and agreements.[9]

On May 1, 2020, the Joint Utilities filed proposed renewable gas (RG) interconnection and operating agreements for the SRGI Tariff.

On July 27, 2020, the Commission issued its proposed decision (PD) on the SRGI Tariff that included changes to the SRGI Tariff's language.

On September 4, 2020, the Commission issued D.20-08-035 adopting the SRGI Tariff.

B. The Original Application for a Hydrogen Blending Demonstration Program

[9] Biomethane Rulemaking, Phase 4 Ruling at 12, *available at* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M320/K307/320307147.PDF.

On November 20, 2020, the Joint Utilities filed A.20-11-004 titled "Joint Application of Joint Utilities Regarding Hydrogen-Related Additions or Revisions to the SRGIT." In A.20-11-004, SoCalGas and SDG&E proposed hydrogen blending demonstration projects in their respective territories, and PG&E and Southwest Gas each requested memorandum accounts to record any incremental costs that may be incurred in developing and implementing a hydrogen injection standard.[10]

On July 15, 2021, the Commission issued D.21-07-005, which dismissed without prejudice A.20-11-004 and ordered that a future application would need to show: (1) improved collaboration with UC Riverside, the California Energy Commission (CEC), and other stakeholders that would inform "whether any parts of the Program can be implemented and funded through the UC Riverside and CEC research projects, and/or can be improved to supplement and complement the UC Riverside and CEC projects to address knowledge gaps;"[11] (2) how the results would apply to all of the Joint Utilities' gas pipeline networks and include a detailed timeline, budget for Commission approval, and details about each of the Program's components;[12] (3) how the blending program used existing Commission authorized funding, where possible;[13] (4) "sufficient information on total application costs and recovery," including "a breakdown of capital and O&M costs of a new or improved program;"[14] (5) the extent research will be conducted on "distribution or transmission pipelines to test the effect of hydrogen embrittlement and the durability and integrity of pipeline materials" and components;[15] and (6) how interim reporting will be conducted.[16]

On September 28, 2021, the CEC issued solicitation GFO-21-503 - Examining the Effects of Hydrogen in End-Use Appliances for Large Commercial Buildings and Industrial Applications (CEC H2 End-Use Solicitation).[17] This solicitation focused on "blending hydrogen with pipeline gas to achieve decarbonization in two targeted end use applications: the power generation and

[10] A.20-11-004 at 1-2.
[11] D.21-07-007 at 23.
[12] *Id*. at 24.
[13] *Id*.
[14] *Id*. at 25.
[15] *Id*. at 26.
[16] *Id*.
[17] Available at https://www.energy.ca.gov/solicitations/2021-09/gfo-21-503-examining-effects-hydrogen-end-use-appliances-large-commercial.

industrial sectors."[18] The CEC clarified that "[t]he project does not require testing or demonstration of hydrogen blending in live pipelines due to the lack of a pipeline hydrogen injection standard in California."[19] On April 8, 2022, the CEC issued the Notice of Proposed Award to fund a project to be led by GTI Energy. Consistent with D.21-07-005, SoCalGas provided a Letter of Support committing $700,000 to support this hydrogen blending project.

On January 28, 2022, the CEC issued solicitation GFO-21-507 – Targeted Hydrogen Blending in Existing Gas Network for Decarbonization (CEC H2 Blending Solicitation).[20] Notably, this solicitation is also focused on conducting hydrogen blending research in power generation and industrial sectors.[21] It "does not require testing or demonstration of hydrogen blending in live pipelines due to the lack of a pipeline hydrogen injection standard in California. Lab testing will be required, simulating conditions as similar to actual operating conditions as possible."[22] On June 14, 2022, the CEC issued the Notice of Proposed Award to fund a project to be led by University of California, Los Angeles. Consistent with D.21-07-005, SoCalGas provided a Letter of Support for this project and committed to (1) provide pipeline system information in SoCalGas' service territory to the project team as needed, and (2) provide internal staff time for meetings, technical input, and discussion as an in-kind contribution.

C. The UC Riverside Study

In July 2022, the CPUC published the UC Riverside Study it sponsored that was prepared by UC Riverside in collaboration with GTI Energy. The goal of the study was to determine the viability of blending hydrogen with natural gas in California's existing natural gas infrastructure based on existing information and targeted experimental and modeling work. The study specifically investigated the maximum hydrogen blending percentage at which no or minor modifications are required to existing natural gas infrastructure and end-use systems, potential modifications required at higher blending percentages, impact and safety considerations related to

[18] CEC H2 End-Use Solicitation Manual Addendum at 2, *available at*: https://www.energy.ca.gov/sites/default/files/2021-11/00%20GFO-21-503%20Solicitation%20Manual%20Addendum%2001_ADA%20_0.docx.
[19] *Id.* at 5.
[20] Available at https://www.energy.ca.gov/solicitations/2022-01/gfo-21-507-targeted-hydrogen-blending-existing-gas-network-decarbonization.
[21] CEC H2 Blending Solicitation Manual at 5-6, *available at:* https://www.energy.ca.gov/sites/default/files/2022-01/00_GFO-21-507_Solicitation_Manual_ada.docx.
[22] *Id*. at 5.

end-use appliances, degradation and durability of the existing pipeline system components (e.g., valves, fittings), leakage rates, impacts on natural gas storage, and cathodically protected pipelines. As part of its findings, UC Riverside recognized that a single, systemwide injection standard would have to consider the most susceptible conditions observed through all infrastructure components as well as end-uses, appliances, and industrial processes.

The UC Riverside Study also recognized that "as there are knowledge gaps in several areas, including those that cannot be addressed through modeling or laboratory scale experimental work, it is critical to conduct real world demonstration of hydrogen blending under safe and controlled conditions."[23] It recommends that the utilities "conduct demonstration of hydrogen blending in a section of the infrastructure that is isolated or is custom-built to include the commonly present materials, vintages, facilities, and equipment of the generic California natural gas infrastructure with appropriate maintenance, monitoring and safety protocols over extended periods."[24] The recommended hydrogen percentages for this demonstration are 5 to 20%, and the study noted, "Such demonstration projects will allow critical knowledge gaps to be filled, including the effect of parameters such as weather induced temperature changes, pressure cycling, length of exposure, effect of natural gas components and contaminants, and potential mitigation techniques."[25] Successful evaluation of hydrogen blending percentages upwards of 5% proposed in the Joint Utilities' Projects fill some of the knowledge gaps surrounding materials and impacts at 5 to 20% blending percentages.

D. Pilot Project Requirements Under D.22-12-057

On December 19, 2022, the Commission issued D.22-12-057 directing "the development of pilot projects to further evaluate standards for the safe injection of clean renewable hydrogen into California's common carrier pipeline system by specifying permissible injection thresholds, locations, testing requirements, and independent analysis."[26] These projects must test hydrogen blending at concentrations exceeding the trigger level of 0.1 percent that:

a. Ensures the long-term safety of the California pipeline, the prevention of hydrogen leakage, the inclusion of hydrogen monitoring, the consideration of the dilution rate, and

[23] UC Riverside, *Hydrogen Blending Impacts Study* (July 2022) at 4; *available at* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.
[24] *Id.*
25 *Id*. at 5.
[26] D.22-12-057 at 1.

the monitoring and reporting of all mechanical characteristics of hydrogen blends in the natural gas pipeline stream;

b. Prevents hydrogen from reaching natural gas storage areas and electrical switching equipment directly or through leakage;
c. Avoids end user appliance malfunctions;
d. Evaluates hydrogen injection at blends between 0.1 and five percent and five to twenty percent; such evaluations must adhere to approved monitoring, reporting, and long-term impact study in accordance with the approval of the pilot project application, and must include validation programs to confirm performance;
e. Specifies the amounts of funding necessary to complete all aspects of the proposal and proposes testing durations adequate to draw meaningful conclusions;
f. Is consistent with all directed courses of action specified in this decision relevant to leakage, reporting, heating value, system safety, environmental considerations, end-use emissions, and all other elements enumerated in this decision;
g. Proposes rigorous testing protocols consistent with the UC Riverside Study;
h. Takes into account parties' comments and further stakeholder input and includes the opportunity for compensation for parties and for community-based organizations;
i. Proposes a methodology for performing a Hydrogen Blending System Impact Analysis that can ensure that any hydrogen blend will not pose a risk to the common carrier pipeline system;
j. Includes new or revised heating values and discusses whether heating values would be modified through the use of propane or other means and whether such modifications to heating value can be done safely;
k. Demonstrates the ability to reliably detect leakage of any hydrogen, methane, or hydrogen/methane blends and describes rigorous hydrogen leak testing protocols that are consistent with leak testing and reporting elements identified in the University of California at Riverside's 2022 Hydrogen Blending Impacts Study, identifies and addresses the comments presented by parties in this proceeding regarding leak issues, and identifies and addresses the comments presented by workshop stakeholders in this proceeding regarding leak issues; and
l. Contains an independent research plan for assessment, measurement, monitoring, and reporting through an independent party, which must be engaged in such activities during the development, construction, operational life, and decommissioning of the pilot project.[27]

III. PURPOSE OF AMENDED APPLICATION AND RELIEF SOUGHT

The purpose of this Amended Application is to (1) propose Projects consistent with D.22-12-057 and D.21-07-005, and (2) inform the development of a future systemwide hydrogen injection standard that allows for blending up to 20%. The Amended Application seeks approval of these Projects along with a revenue requirement required to implement the Projects taking place in each of the Joint Utilities' respective service territories.

[27] D.22-12-057, OP 7 at 68-70 (as corrected by D.23-02-043).

IV. THERE ARE STRONG POLICY REASONS FOR CONDUCTING THE PROJECTS

As emphasized in D.22-12-057, "The UC Riverside Study comments that hydrogen blending can be an important decarbonization strategy for the energy and transportation sectors."[28] The Joint Utilities support California's climate and energy goals, including Senate Bill (SB) 32,[29] achieving carbon neutrality by 2045 (E.O. B-55-18),[30] and fulfilling the 100% Clean Energy Act of 2018 by 2045 (SB 100).[31] Furthermore, the Commission recognized that the "UC Riverside Study provides support for pursuing hydrogen blending as part of a decarbonization strategy, while at the same time, outlining thoughtful and prudent next steps before establishing a system wide injection standard."[32] The Joint Utilities acknowledge various challenges that will need to be addressed to meet these targets and recognize that both clean molecules and clean electrons, as well as a diverse energy technology toolkit, will likely be required to reach carbon neutrality while providing safe, reliable, and resilient energy.

Hydrogen is poised to become an essential component of the low carbon energy economy of the future. Hydrogen blending feasibility studies are being safely conducted across the globe, due to its potential to achieve energy decarbonization at scale.[33] The flexibility of hydrogen as an energy carrier across multiple sectors makes it a unique carbon neutral energy solution enabling transportation, distribution, and storage of clean energy. At its July 2021 workshop, the California Energy Commission (CEC) recognized the importance of hydrogen, stating, "[A]s we look at different options and alternatives for the state to transition to a decarbonized electricity system by 2045, hydrogen has emerged as an important element that we need to assess and understand," especially for grid reliability.

Since the original filing of A.22-09-006 in September 2022, there have been significant California and federal initiatives supporting the role of hydrogen for decarbonization. The

[28] *Id*., Finding of Fact (FOF) 17 at 56.
[29] California Senate Bill 32 (Pavley, 2016), *available at:* https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB32.
[30] Executive Dept., State of California, "Executive Order B-55-18 To Achieve Carbon Neutrality" *available at:* https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf.
[31] California Senate Bill 100 (De León, 2018), *available at*: https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.
[32] D.22-12-057, FOF 19 at 57.
[33] International Energy Agency, "Global Hydrogen Review 2022." Table, "Selected operational and planned hydrogen blending projects in distribution networks." P.118-119 *available at*: https://www.iea.org/reports/global-hydrogen-review-2022

California Air Resources Board (CARB) 2022 Scoping Plan adopted in its reference scenario renewable hydrogen blended in fossil gas pipeline at 7% energy (~20% by volume), ramping up between 2030 and 2040.[34] In August 2023, Governor Newsom directed the Governor's Office of Business and Economic Development (GO-Biz) to develop California's Hydrogen Market Development Strategy, employing an all-of-government approach to building up California's clean, renewable hydrogen market. "California is all in on clean, renewable hydrogen – an essential aspect of how we'll power our future and cut pollution," said Governor Newsom.[35]

In October 2023, the US Department of Energy (DOE) selected California as a National Hydrogen Hub, enabling the state to receive up to $1.2 billion in federal funding to accelerate the development and deployment of clean, renewable hydrogen. US Senator Alex Padilla stated, "The production and implementation of clean, renewable hydrogen is essential to fully decarbonize our region's industries, foster clean energy job growth, and meet California's ambitious carbon neutrality goals." [36]

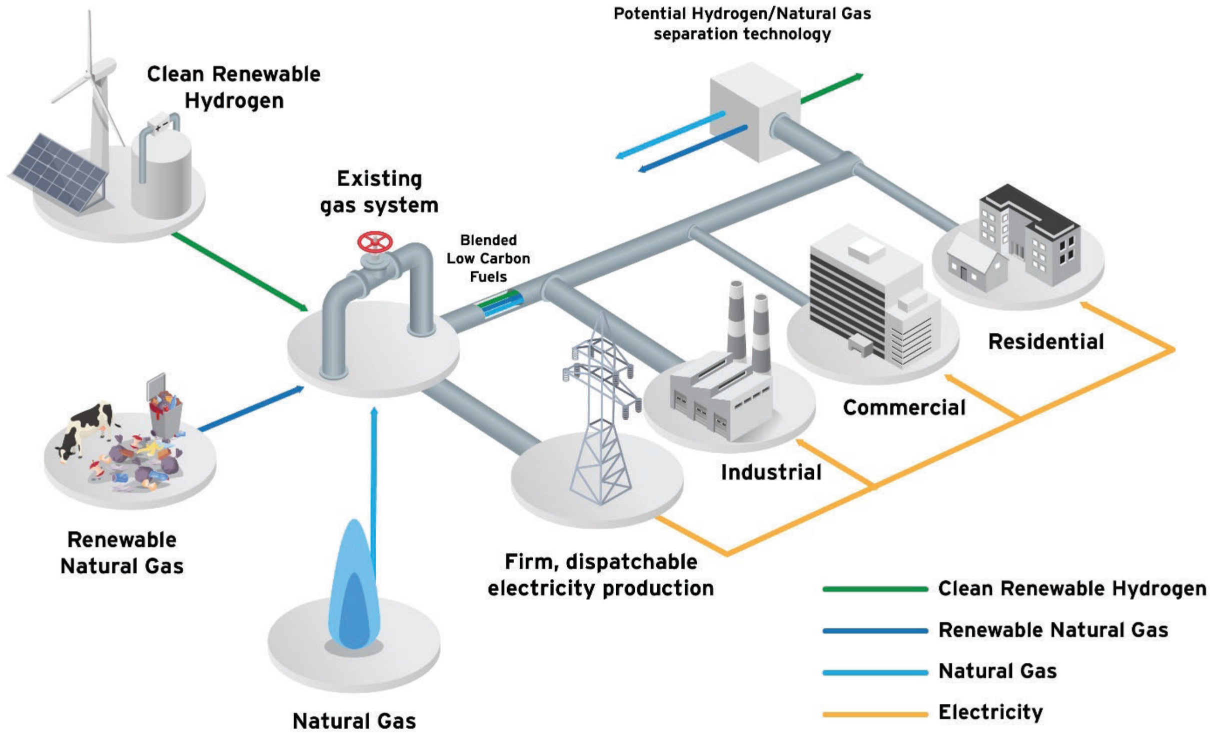
As indicated in Figure 1 below, blending hydrogen has the potential to lower greenhouse gas (GHG) emissions on both the electric and gas grids, serve as a low-cost hydrogen storage and transportation medium, and provide system reliability and resiliency through energy diversity and redundancy. In the future, hydrogen separation technology may be added to the system for specific end point applications requiring pure hydrogen fuel.

[34] California Air Resources Board, "2022 Scoping Plan for Achieving Carbon Neutrality" (December 2022) at 78. *Available at*: https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.

[35] Office of Governor Gavin Newsom, "Governor Newsom Announces New Strategy to Develop a Hydrogen Economy of the Future" (August 8, 2023), *available at:* https://www.gov.ca.gov/2023/08/08/governor-newsom-announces-new-strategy-to-develop-a-hydrogen-economy-of-the-future/.

[36] Office of Governor Gavin Newsom, "California Selected as a National Hydrogen Hub" (October 13, 2023), *available at:* https://www.gov.ca.gov/2023/10/13/california-selected-as-a-national-hydrogen-hub/#:~:text=SACRAMENTO%20%E2%80%93%20California%20will%20receive%20up,the%20clean%20energy%20economy%20statewide.

Figure 1: Hydrogen Blending on the Gas System



Since hydrogen gas is made up of carbon-free molecules, blending it with natural gas could make a significant contribution to lower carbon emissions in various sectors of the economy. For example, at a 20% hydrogen blend by volume, the typical carbon dioxide (CO_2) reduction potential of hydrogen is 6.3%.[37] Given the scale of the gas system today, a 6.3% CO_2 reduction would be significant: if California's gas system contained 20% hydrogen by volume in 2020,[38] the CO_2 reduction would be equivalent to removing 1.52 million gasoline-powered passenger vehicles from the road, or replacing about 6% of California's registered automobiles

[37] International Energy Agency, *Reduction of CO_2 Emissions by Adding Hydrogen to Natural Gas. Report No. PH4/24* (October 2003), *available at:* https://ieaghg.org/docs/General_Docs/Reports/Ph4-24%20Hydrogen%20in%20nat%20gas.pdf.

[38] As of May 10, 2022, the 2022 California Air Resources Board's (CARB) Draft Scoping Plan Update's selected Proposed Scenario (Alternative 3) includes renewable hydrogen blended in natural gas pipelines at 7% energy (~20% by volume), ramping up between 2030 and 2045. [38] California Air Resources Board, *Draft 2022 Scoping Plan Update* (May 10, 2022), *available at:* https://ww2.arb.ca.gov/sites/default/files/2022-05/2022-draft-sp.pdf.

with zero emission vehicles.[39]

California has a policy mandate to aggressively reduce fossil fuels wherever they are currently used in California. Establishing a hydrogen blending injection standard can accelerate the market and adoption of clean fuels and move California closer to achieving broader energy system decarbonization. Distributing hydrogen through the state's existing common carrier natural gas pipeline system and delivering it to connected end users can materially reduce the state's emissions and contribute to California's goals for carbon neutrality.

V. SUMMARY OF TESTIMONY

Consistent with the requirements in D.22-12-057, support for the Joint Utilities' requests is provided in the accompanying prepared direct testimony and attachments. The direct testimony consists of seven chapters: (1) Technical Presentation – SoCalGas Closed System Project (Blaine Waymire), (2) Technical Presentation – SoCalGas Open System Project (Blaine Waymire), (3) Technical Presentation – SDG&E Project (Pooyan Kabir), (4) Technical Presentation – Southwest Gas Project (Kevin Lang), (5) Technical Presentation – PG&E (Danielle Mark), (6) Regulatory Accounting, Cost Recovery, Revenue Requirement, and Rates – SoCalGas Project (Nasim Ahmed and Marjorie Schmidt-Pines), (7) Regulatory Accounting, Cost Recovery, Revenue Requirement, and Rates – SDG&E Project (Eric Dalton, Jack Guidi, and Marjorie Schmidt-Pines), and (8) Regulatory Accounting, Cost Recovery, Revenue Requirement, and Rates – Southwest Gas Project (Randi Cunningham); and (9) Regulatory Accounting, Cost Recovery, Revenue Requirement, and Rates – PG&E Project (Shannon Sims, Isaac Tam, and Patricia Gideon).

The Joint Utilities are coordinating their respective Projects, summarized below, to

[39] U.S. Energy Information Administration, *Natural Gas Delivered to Consumers in California*, *available at:* https://www.eia.gov/dnav/ng/hist/n3060ca2m.htm; U.S. Environmental Protection Agency, *Greenhouse Gas Emissions from a Typical Passenger Vehicle*, *available at:* https://www.epa.gov/greenvehicles/greenhouse-gas-emissions-typical-passenger-vehicle; California Department of Motor Vehicles, *Estimated Vehicles Registered by County for the Period of January 1 through December 31, 2020*, *available at:* https://www.dmv.ca.gov/portal/uploads/2021/02/estimated_fee_paid_by_county_report.pdf; Calculation: (2,019 BCF of natural gas consumed in CA 2020)*(0.0552 kg CO_2/CF) produces 112.16 MMT CO_2/year from natural gas system. If 20% of the natural gas by volume had been replaced by hydrogen: 6.3%*111MMT CO_2 = 7.0 MMT of CO_2 emissions could have been avoided. In passenger vehicle equivalency, (7.0 MMT of CO_2*10^6)/4.5 MT CO_2/car/year (per EPA average) = 1,524,280 cars removed from the road. As there were 25,507,660 registered cars in California in 2020, this is equivalent to removing 6% of all cars from the road in California.

minimize redundancy while simultaneously gathering necessary data to support a statewide hydrogen blending standard compatible with the varied gas system infrastructure and end-user equipment and applications. These Projects build off prior research and will provide proof of concept for the economical and safe use of blended hydrogen in the gas system as part of California's decarbonization efforts. The Joint Utilities emphasize that safety was at the core of each Project's respective design and objectives.

a. Chapter 1: Technical Presentation – SoCalGas Project (Closed System)

Chapter 1, the direct testimony of Blaine Waymire, outlines the technical, operational, cost, and safety details for SoCalGas's proposed Closed System Project. The Closed System Project's purpose is to demonstrate and gather data on the safe use of increasing concentrations of blended hydrogen gas under real world conditions in a "closed system portion" of the SoCalGas medium-pressure steel and plastic distribution pipeline system, serving existing gas appliances and end-uses.

SoCalGas will collaborate with UC Irvine to conduct the Closed System Project at the Anteater Recreation Center (ARC) on the UC Irvine campus. Portions of the campus's distribution system will be isolated so that only the ARC will receive the hydrogen blend to serve light commercial equipment in the ARC, such as boilers and pool heaters. The Closed System Project will begin testing blend concentrations of 5% and incrementally increase the hydrogen concentrations up to 20% based on safety and technical feasibility testing throughout the demonstration. The Closed System Project will take place over four chronological phases. The two initial planning and demonstration phases span approximately three years to allow for the collection and evaluation of data across time and seasonal operating conditions. The two final phases will decommission the project and analyze and report on the project data and results.

SoCalGas's Closed System Project builds upon the success of a similarly designed trial in the United Kingdom, the HyDeploy Trial at Keele University, that used up to 20% hydrogen concentration blends and incorporates the recommendations from GTI Energy and the UC Riverside Study. The Closed System Project will support the development of a state-wide hydrogen injection standard and address hydrogen blending knowledge gaps, safety and maintenance protocols, mitigation strategies, stakeholder input, and many other learnings necessary to implement hydrogen blending at 5-20% concentrations into the gas distribution system.

b. Chapter 2: Technical Presentation – SoCalGas Project (Open System)

Chapter 2, the direct testimony of Blaine Waymire, outlines the technical, operational, cost, and safety details for SoCalGas's proposed Open System Project. In tandem with the Closed System Project, SoCalGas's Open System Project's purpose is to demonstrate and gather data on the safe use of increasing concentrations of blended hydrogen gas under real-world conditions in an "open portion" of SoCalGas's medium-pressure mixed material distribution system serving SoCalGas residential and commercial customers. Testing on an open portion of the distribution system is necessary because it will show what happens when hydrogen is blended into the distribution system and served to many customers with varied end uses.

SoCalGas is collaborating with the City of Orange Cove, where the Open System Project would be located. This location is advantageous because it is located just downstream of a regulator station so that the entire community receives the blended gas. The Open System Project involves mixed material distribution pipelines serving approximately 2,000 meters and 10,000 residents as well as commercial customers. The Open System Project will begin testing blend concentrations of 0.1% and incrementally increasing the hydrogen concentrations up to 5% based on safety and technical feasibility testing throughout the project. The Open System Project will take place over four chronological phases. The first two initial planning and demonstration phases span approximately three years to allow for the collection and evaluation of data across time and seasonal operating conditions. The two final phases will analyze and report on the project results and decommission the project equipment only if required to do so. SoCalGas intends to donate certain portions of the equipment to the City of Orange Cove for local community use.

The Open System Project builds on the success of a similarly designed study by ATCO in Canada where roughly 2,100 customers are already receiving 5% hydrogen gas blends, with some soon to receive concentrations of 20%. The Open System Project also incorporates the input received from several stakeholder and recommendations from the UC Riverside Study to develop data to support a state-wide hydrogen injection standard.

c. Chapter 3: Technical Presentation – SDG&E Project

Chapter 3, the direct testimony of Pooyan Kabir, outlines the technical, operational, cost, and safety details for SDG&E's proposed Hydrogen Blending Demonstration Project. Similar to SoCalGas' Closed System Project, the purpose of SDG&E's Project is to assess the safety and efficacy of hydrogen blending and demonstrate the safe use of hydrogen gas blending under real world conditions in an "closed system portion" of SDG&E's plastic pipeline distribution system.

SDG&E is collaborating with UC San Diego (UCSD), and the Project will be held on UCSD property. The Project will use blended gas to continuously feed a fuel cell, which will feed electricity to the SDG&E grid. SDG&E will install a brand-new, custom-built medium pressure polyethylene (PE) distribution pipe system, closely resembling the existing distribution system in all respects, which will carry blended gas to the fuel cell. The Project will begin testing blend concentrations of 5% and incrementally increase the hydrogen concentrations up to 20% based on safety and technical feasibility testing throughout the Project. Testing the potential effects of hydrogen blends on PE pipeline system is necessary because it is the most common distribution piping material in SDG&E's system and is the most common material used for distribution asset replacements. The Project will be divided into four chronological phases. The two initial planning and demonstration phases span approximately three years to allow for the collection and evaluation of data across time and seasonal operating conditions. The two final phases will decommission the Project, restore the campus to its original state, and analyze and report on the Project data and results.

Like SoCalGas's Closed System Project, SDG&E's Project built upon the successes of the United Kingdom's HyDeploy Project, incorporates the recommendations of the UC Riverside Study, and will support the development of a statewide hydrogen injection standard, with a focus on the material impacts of hydrogen blended with natural gas in common polyethylene pipe in a temperate, low elevation location. The total direct cost estimate is $16.1 million.

d. Chapter 4: Technical Presentation – Southwest Gas Project

Chapter 4, the direct testimony of Kevin Lang, outlines the safety, technical, operational, cost, and additional planning details for Southwest Gas's proposed project. The purpose of Southwest Gas' Project is to gather, analyze, and draw conclusions on data from blending hydrogen into a small, isolated portion of a natural gas pipeline system in one of California's coldest regions. Real-life demonstrations of hydrogen blending in *real-life* conditions, such as California's extremely cold alpine region, are necessary to develop a holistic hydrogen injection standard that accounts for the conditions of the state. The scope of this project is an isolated stretch of high-density plastic pipeline containing less than 20 commercial customers and no residential customers. The first customer attached to the Project that would first receive blended gas is Southwest Gas's District Operations building as proof of the confidence Southwest Gas has in the safety and operations of this data-collection project. The Project would introduce blended hydrogen in the system to collect information relevant to developing a hydrogen injection standard to reduce greenhouse gas emissions for the state.

Through this Project, Southwest Gas plans to inject increasing concentrations of locally produced hydrogen, incrementally rising up to 20% hydrogen by volume, into a short, isolated portion of Truckee's natural gas pipeline system over the course of 18 months. This initiative is to develop decarbonized technology in Truckee's natural gas supply, creating an additional pathway to reduce greenhouse gas emissions in the pipeline system. By assessing the safety and performance of different hydrogen blend concentrations at high elevations and in the extreme weather conditions experienced in Northern California, this project contributes to one 1 of 4 proposed by the California joint investor-owned utilities intended to collectively gather data throughout the various conditions in California to create a hydrogen injection standard that will help towards achieving the state's climate goals. The two initial planning and demonstration phases span approximately 3.5 years. The two final phases will decommission the Project, remove the Project equipment, and analyze and publicly report on the Project data and results. The total direct cost estimate is approximately $10.2 million.

e. Chapter 5: Technical Presentation – PG&E Project

Chapter 5, the direct testimony of Danielle Mark, outlines the technical, operational, cost, and safety details for PG&E's proposed Project. This Project's purpose is to conduct a large-scale and long-term (ten years) field demonstration of the safe use of blended hydrogen gas on a newly constructed, stand-alone high pressure steel gas transmission system operating in PG&E's service area. PG&E cannot feasibly perform this Project on its existing transmission system because no representative portion of the transmission system can be isolated. The Joint Utilities are unaware of any hydrogen blending project focusing on the gas transmission system in North America. Therefore, PG&E's Project is a critical complement to the other Joint Utilities' respective distribution-focused projects and represents an important area of research as the state evaluates hydrogen for blending and injecting in its common carrier gas pipeline system.

The Project will be located in Lodi, CA, where the Northern California Power Agency (NCPA) power generation plant, Lodi Energy Center (LEC), is currently situated. The Project consists of a large test loop representing the high-pressure gas transmission system with testing, monitoring, and other facilities attached to the loop. The Project will begin with blending concentrations of 5% hydrogen by volume followed by a stepwise increase to 10%, 15%, and finally up to 20% with the potential for higher concentrations in the future. The blended gas will be transported through the stand-alone transmission system at approximately 720 psi. In addition, utilities, vendors and other stakeholders with transmission equipment and pipe may connect equipment to the loop for testing. PG&E is also partnering with UC Riverside's Center for Environmental Research and Technology (CE-CERT), which will take an advisory role to ensure proper protocols and conduct a life cycle assessment and techno-economic analysis. The Project will unfold over three chronological phases, with the initial planning and construction phase scheduled into 2027 and the second testing and demonstration phase expected to last ten years. The final phase will entail assessing whether the Project Facilities can be left in place as operating assets or will need to be decommissioned and removed.

PG&E's Project will close hydrogen blending knowledge gaps by providing long-term operational data on the impacts of hydrogen blending in the transmission pipeline system. In developing the Project, PG&E collaborated with several stakeholders, including research universities, government agencies, and industry experts.

f. Chapter 6: Regulatory Accounting, Cost Recovery, Revenue Requirement, and Rates – SoCalGas's Projects

Chapter 6, the direct testimony of Nasim Ahmed and Marjorie Schmidt-Pines, presents SoCalGas's request to establish a Hydrogen Blending Demonstration Project Balancing Account, or the HBDPBA, and the estimated costs and revenue requirements for its proposed Projects (see Chapters 1 and 2). SoCalGas's proposed HBDPBA would be an interest-bearing, two-way balancing account recorded on its financial statements. The HBDPBA will consist of two subaccounts. The first will record the difference between the authorized funding in rates approved in the Amended Application and actual incremental O&M costs. The second will record SoCalGas's allocation of costs associated with the independent research study to be conducted by an independent third-party, continued workshops with the opportunity for parties and CBOs to seek compensation, and other reports described in D.22-12-057.

SoCalGas proposes to recover its costs recorded in the HBDPBA in transportation rates using the Equal Cents Per Therm (ECPT) cost allocation methodology. The ECPT cost allocation method allocates costs across customer classes based on each customer class's respective share of total average year gas demand. SoCalGas forecasts a total revenue requirement of $80.4 million for its projects.

g. Chapter 7: Regulatory Accounting, Cost Recovery, Revenue Requirement, and Rates – SDG&E's Project

Chapter 7, the direct testimony of Eric Dalton, Jack Guidi, and Marjorie Schmidt-Pines, presents SDG&E's request to establish a HBDPBA and presents the estimated costs and revenue requirements for its proposed Project (see Chapter 3). SDG&E's anticipated HBDPBA would be an interest-bearing, two-way balancing account recorded on its financial statements. The HBDPBA will consist of two subaccounts. The first will record the difference between the authorized funding in rates approved in the Amended Application and actual incremental O&M costs. The second will record SDG&E's proportional share of the cost allocation for shared studies described in D.22-12-057.

SDG&E also proposes to recover its costs recorded in the HBDPBA through transportation rates using the ECPT cost allocation methodology. SDG&E forecasts a total revenue requirement of $21.0 million, with 2025 having a peak revenue requirement of $9 million, for its Project.

h. Chapter 8: Regulatory Accounting, Cost Recovery, Revenue Requirement, and Rates – Southwest Gas's Project

Chapter 8, the direct testimony of Randi Cunningham, presents Southwest Gas's request to establish a HBDPBA and presents the estimated costs and revenue requirements for its proposed Hydrogen Blending Demonstration Project (see Chapter 4). Southwest Gas's anticipated HBDPBA would be an interest-bearing, two-way balancing account recorded on its financial statements. Southwest Gas proposes to recover its costs recorded in the HBDPBA through rates using a flat volumetric cost allocation methodology applicable to all Southwest Gas California jurisdictional customers. Southwest Gas estimates that the total revenue requirement to be recorded to the HBDPBA will be based on a Project cost of approximately $10.21 million.

i. Chapter 9: Regulatory Accounting, Cost Recovery, Revenue Requirement, and Rates – PG&E's Project

Chapter 9, the direct testimony of Shannon Sims, Isaac Tam, and Patricia Gideon presents PG&E's request to establish a HBDPBA and presents the estimated costs and revenue requirements for its proposed Projects (see Chapter 5). The proposed HBDPBA would consist of two subaccounts: (1) a two-way Hydrogen Demonstration Project Subaccount and (2) an Administrative Memorandum Subaccount. PG&E will include a line item in its proposed new Hydrogen Demonstration Project Subaccount to account for any external funding received for the Project. PG&E proposes to recover the proposed revenue requirement on an ECPT basis through the rate component of the Noncore Cost Subaccount of the Noncore Customer Class Charge Account and the Core Cost Subaccount of the Core Fixed Cost Account. PG&E forecasts a revenue requirement for its Project of $94.2 million.

VI. COMPLIANCE WITH OP 7(L) OF D.22-12-057

D.22-12-057 OP 7 (L) requires the Joint Utilities to develop a research plan through an independent party. In order to avoid ratepayers incurring unnecessary costs, the Joint Utilities will develop a research plan through retained third-party expert(s) upon Amended Application approval. On September 29, 2023, the Joint Utilities discussed the independent research plan with Energy Division (ED). The Joint Utilities advised ED that because each of the Projects is different, it may not be possible to find a single independent party who has adequate expertise to cover all the Projects. For example, an independent third-party is needed for the distribution-focused Projects, and another for the transmission-focused Project. Therefore, the Joint Utilities may find it necessary to seek more than one third party expert for different portions of the Projects.

The Joint Utilities also discussed with ED that they will wait until the Amended Application has been approved prior to issuing a Request for Proposals (RFP) to solicit competitive bids for a third-party(ies) to develop an independent research plan for assessment, measurement, monitoring, and reporting of the Projects through the development, construction, operational, life, and decommissioning of the Pilots. The Joint Utilities note that all activities leading up to the filing of this application are considered “pre-development.” Development activities will begin upon the application’s approval. The exception is PG&E’s Project, which has already conducted an FEL-1 (conceptual design) in collaboration with experienced third-party groups. Details on this are addressed in Chapter 5, PG&E’s Technical Chapter.

The cost for the Independent Research Plan will be tracked through sub-memorandum accounts and the Joint Utilities shall pay their proportionate shares for the awarded third-party based on the utilities’ gas throughput in the 2016 California Gas Report referenced in OP 9 of

D.22-12-057: Pacific Gas and Electric Company (50.89%), San Diego Gas & Electric Company (6.43%), Southern California Gas Company (41.92%), and Southwest Gas Corporation (0.77%).

VII. COMPLIANCE WITH OP 10 OF D.22-12-057

OP 10 provides that the Hydrogen Compendium Report (Compendium Report) shall be filed within two years of the issuance of the decision (i.e., by December 15, 2024). However, as discussed with ED on September 29, 2023, within one year of the Amended Application's approval, the Joint Utilities will submit the Compendium Report. This timeline is recommended to avoid ratepayers incurring unnecessary costs because the decision approving the Amended Application may include guidance that could inform the Compendium Report's content and preparation. The Joint Utilities will issue an RFP to solicit competitive bids for a third-party to complete the Compendium Report. This can be viewed as a follow-up to the literature review performed by UC Riverside under the overall Hydrogen Impacts Analysis. The cost for the Compendium Report will be tracked through sub-memorandum accounts and the Joint Utilities shall pay their proportionate shares for the awarded third party based on the utilities' gas throughput in the 2016 California Gas Report referenced in OP 9 of D.22-12-057: Pacific Gas and Electric Company (50.89%), San Diego Gas & Electric Company (6.43%), Southern California Gas Company (41.92%), and Southwest Gas Corporation (0.77%).

VIII. COMPLIANCE WITH OP 11 OF D.22-12-057

The Joint Utilities held two public workshops to gather feedback from stakeholders and industry experts, underscoring the Joint Utilities' efforts to collaborate and improve the design of the Projects. As instructed by D.22-12-057, coordination with ED to plan the workshop began within six (6) months of the decision. The Joint Utilities met with Energy Division three times before the first workshop, on January 26, 2023, March 28, 2023, and May 18, 2023. The Joint Utilities met with ED on September 29, 2023 to discuss the second workshop.

On June 13, 2023, the Joint Utilities held the first virtual public workshop to present an overview of their respective Projects (as formulated at that time) and solicit feedback from various stakeholders. This workshop summarized each Project and included a presentation by a UC Riverside professor highlighting findings of the UC Riverside Study, as well as a presentation from ATCO on their open system hydrogen blending project in Fort Saskatchewan, Canada. The workshop held designated time for verbal and written stakeholder feedback. Comments and questions received focused on the source of hydrogen, leakage issues, stakeholder engagement to date, and environmental considerations. The Joint Utilities responded to several verbal questions.

On November 6, 2023, the Joint Utilities held a second public stakeholder workshop focused on technical issues, where they shared draft testing plans, discussed how they would assess potential environmental impacts, and solicited input from stakeholders. The workshop held designated time for verbal and written stakeholder feedback. The workshop also included a public Question and Answer session with a distinguished panel of leading national hydrogen blending experts including from the National Renewable Energy Laboratory, the Pacific Northwest National Laboratory, and Sandia National Laboratory. For both workshops, the Joint Utilities responded via written communication to submitted questions that were not addressed during the respective live events.

Among feedback received from the second workshop was a letter from the Sierra Club on November 15, 2023, which included suggestions such as robust public engagement, robust emission and leakage monitoring, and designating a utility contact where customers can request information or report issues. Suggestions in the letter were reviewed, and in some cases, adopted. For example, in response to Sierra Club feedback, SoCalGas clarified in its testimony that it would add continuous monitoring for hydrogen leakage on the production, storage and blending area and automatic shutdown should a leak be detected. SDG&E adjusted its design to include fixed continuous monitoring for hydrogen leakage with automatic hydrogen system shutdown capabilities.

IX. COMPLIANCE WITH D.21-07-005

To the extent applicable, the Joint Utilities also followed the guidance the Commission provided in D.21-07-005 that includes (1) improved collaboration with UC Riverside, the CEC, and other stakeholders;[40] (2) how the results would apply to all of the Joint Utilities' gas pipeline networks and include a detailed timeline, budget for Commission approval, and details about each of the Program's components;[41] (3) the extent research will be conducted on "distribution or transmission pipelines to test the effect of hydrogen embrittlement and the durability and integrity

[40] D.21-07-007 at 23.
[41] *Id*. at 24.

of pipeline materials" and components;[42] and (4) how reporting will be conducted, such as interim reports and publishing bi-annual or annual reports on research progress.[43]

Since D.21-07-005 was issued in July 2021, SoCalGas, SDG&E, and Southwest Gas further collaborated with UC Riverside before filing A.22-09-006.[44] Some SoCalGas and PG&E employees were part of UC Riverside's Technical Advisory Committee for the UC Riverside Study. One of the principal investigators for the UC Riverside Study presented also at the Joint Utilities' first public stakeholder engagement workshop.

Furthermore, as noted in the Amended Application,[45] SoCalGas collaborated with the CEC in connection with its solicitation GFO-21-503 issued on September 28, 2021.[46] This solicitation focused on "blending hydrogen with pipeline gas to achieve decarbonization in two targeted end use applications: the power generation and industrial sectors."[47] On April 8, 2022, the CEC issued the Notice of Proposed Award to fund a project to be led by GTI Energy. SoCalGas provided a Letter of Support for this project and committed to provide $700,000 to support this project. Similarly, SoCalGas is the recipient of CEC's solicitation GFO-21-507 issued on January 28, 2022.[48] This solicitation is also focused on conducting hydrogen blending research in power generation and industrial sectors.[49] On June 14, 2022, the CEC issued the Notice of Proposed Award to fund a project to be led by University of California, Los Angeles. SoCalGas and PG&E provided a Letter of Support for this project and committed to (1) provide pipeline system information in SoCalGas's and PG&E's service territory, respectively, to the project team as needed, and (2) provide internal staff time for meetings, technical input, and discussion as an in-kind contribution.

[42] *Id*. at 26.
[43] *Id*.
[44] PG&E was not a party to A.22-09-006 when it was filed in September 2022.
[45] Amended Application at 4-5.
[46] Available at https://www.energy.ca.gov/solicitations/2021-09/gfo-21-503-examining-effects-hydrogen-end-use-appliances-large-commercial.
[47] CEC H2 End-Use Solicitation Manual Addendum at 2, *available at*: https://www.energy.ca.gov/sites/default/files/2021-11/00%20GFO-21-503%20Solicitation%20Manual%20Addendum%2001_ADA%20_0.docx.
[48] Available at https://www.energy.ca.gov/solicitations/2022-01/gfo-21-507-targeted-hydrogen-blending-existing-gas-network-decarbonization.
[49] CEC H2 Blending Solicitation Manual at 5-6, *available at:* https://www.energy.ca.gov/sites/default/files/2022-01/00_GFO-21-507_Solicitation_Manual_ada.docx.

Furthermore, as noted in Chapters 1, 2, 3, 4, and 5 of the Amended Application and above, the results of these Projects can help inform a California system-wide hydrogen injection standard. The testimony chapters in this Amended Application detail how the Projects will test blended hydrogen at increasingly high concentrations on various components of the gas transmission and distribution systems as well as end-use appliances and equipment. The extent research will be conducted on "distribution or transmission pipelines to test the effect of hydrogen embrittlement and the durability and integrity of pipeline materials" and components is also detailed in Chapters 1, 2, 3, 4, and 5. These chapters also include a detailed timeline as well as details about each of the Projects' main components. Chapters 6, 7, 8, and 9 include detailed budgets for each of the Projects for Commission approval.

As recommended in D.21-07-005, the Joint IOUs will collectively provide interim reports on an annual basis starting from one year post Amended Application approval. The Annual Report will include research progress, project updates, and available technical findings. The Annual Report will be available on the relevant Joint Utilities websites and served on the service list. Since the projects have different timelines and durations, as individual Utilities' projects conclude and are reported on, they may no longer provide updates.

In D.21-07-005, the Commission also directed Joint Utilities to make reasonable attempts to use existing Commission-authorized funding and other funds, including the CEC R&D Program and federal funding, to the extent possible.[50] First, Joint Utilities are unaware of Commission-authorized funding for hydrogen blending pilot projects. Similarly, Joint Utilities could not have secured funding from the CEC R&D Program. Although the CEC has issued two hydrogen blending solicitations,[51] they were focused on the power generation and industrial sectors; these solicitations have also explicitly excluded "hydrogen blending in live pipelines due to the lack of a pipeline hydrogen injection standard in California."[52] The Joint Utilities are also unaware of any federal funding opportunities for live blending pilot projects in natural gas pipelines; the existing federal funds under the Infrastructure Investment and Jobs Act of 2021 and

[50] D.21-07-007 at 25.

[51] *See* CEC H2 End Use Solicitation, available at https://www.energy.ca.gov/solicitations/2021-09/gfo-21-503-examining-effects-hydrogen-end-use-appliances-large-commercial; CEC H2 Blending Solicitation, available at https://www.energy.ca.gov/solicitations/2022-01/gfo-21-507-targeted-hydrogen-blending-existing-gas-network-decarbonization.

[52] CEC H2 Blending Solicitation Manual at 5, *available at:* https://www.energy.ca.gov/sites/default/files/2022-01/00_GFO-21-507_Solicitation_Manual_ada.docx.

Inflation Reduction Act of 2022 are focused on fostering the production of clean hydrogen, development of clean hydrogen hubs, carbon management, advancing equipment manufacturing and recycling, and improving the efficiency of electrolysis.[53] Therefore, Joint Utilities did not have other available funding for their proposed Projects.

X. STATUTORY AND PROCEDURAL REQUIREMENTS

This Amended Application is made pursuant to California Public Utilities Code Sections 451, 454, 701, and 1701, Rule 5.2 of the Commission's General Order 96-B, Section 6 of Article XII of the California Constitution, the Commission's Rules of Practice and Procedure, D.22-12-057, D.21-07-005, and relevant decisions, orders, and resolutions of the Commission. In accordance with Rule 2.1(a)-(c) of the Commission's Rules of Practice and Procedure, the Joint Utilities provide the following information.

a. Rule 2.1(a) – Legal Name

SoCalGas is a public utility corporation organized and existing under the laws of the State of California. SoCalGas' principal place of business and mailing address is 555 West Fifth Street, Los Angeles, California, 90013.

SDG&E is a public utility corporation organized and existing under the laws of the State of California. SDG&E is engaged in the business of providing electric service in a portion of Orange County and electric and gas service in San Diego County. SDG&E's principal place of business is 8330 Century Park Court, San Diego, California, 92123.

Southwest Gas is a public utility corporation organized and existing under the laws of the State of California, whose exact legal name is Southwest Gas Corporation. Southwest Gas is engaged in the business of providing gas service in portions of San Bernardino County in Southern California and portions of Placer, El Dorado, and Nevada Counties in Northern California. Southwest Gas is also engaged in the intrastate transmission, distribution, and sale of natural gas as a public utility in certain portions of Nevada and Arizona. Southwest Gas' principal place of business is 8360 South Durango Drive, Las Vegas, Nevada, 89113.

[53] *See, e.g.,* U.S. Department of Energy, *DOE Establishes Bipartisan Infrastructure Law's $9.5 Billion Clean Hydrogen Initiatives* (Feb. 15, 2022), available at https://www.energy.gov/articles/doe-establishes-bipartisan-infrastructure-laws-95-billion-clean-hydrogen-initiatives; *see also* U.S. Department of Energy, *Inflation Reduction Act of 2022*, available at https://www.energy.gov/lpo/inflation-reduction-act-2022 (last visited on Jan. 30, 2024).

PG&E is a public utility corporation duly organized under the State of California. PG&E's principal place of business is 300 Lakeside Drive, Oakland, California 94612.

b. Rule 2.1(b) – Correspondence

All correspondence and communications to SoCalGas regarding this Amended Application should be addressed to:

JORDAN M. CALZADILLAS

Regulatory Case Manager for:
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A copy should also be sent to:

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All correspondence and communications to SDG&E regarding this Amended Application should be addressed to:

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A copy should also be sent to:

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All correspondence and communications to PG&E regarding this Amended Application should be addressed to:

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c. Rule 2.1(c) – Category, Hearings, Issues, Schedule

i. Proposed Category of Proceeding

The Joint Utilities propose that this phase of the proceeding be categorized as "Ratesetting" under Rule 1.3(e) and 7.1(e)(2) because the Amended Application could eventually lead to a potential future effect on the proposed Joint Utilities' rates if the requested balancing accounts and costs are approved, and because the proceeding does not otherwise clearly fit into another category under Rule 1.3.

ii. Need for Hearings

The Joint Utilities anticipate that evidentiary hearings will not be necessary.

iii. Issues to be Considered and Relevant Safety Considerations

The principal issues to be considered in this Amended Application are whether the Commission should approve the Projects, and whether it should therefore grant the relief requested as summarized in Section VII below. There do not appear to be relevant safety concerns with respect to this Amended Application.

iv. Proposed Schedule

The Joint Utilities propose the following schedule for this Amended Application:

EVENT	DATE
Amended Application	March 1, 2024
Responses/Protests	within 30 days Daily Calendar notice
Utilities' Reply Responses/Protests	within 10 days (see Rule 2.6)
Prehearing Conference	May 2024
Scoping Memo	June 2024
Intervenor Testimony	August 2024
Rebuttal Testimony	September 2024
Opening Briefs	September 2024
Reply Briefs	October 2024
Proposed Decision	December 2024
Commission Decision	January 2025

d. Rule 2.1(d) – Safety

The Joint Utilities are committed to safety. Based on current information, the Amended Application will not result in any adverse safety impacts on the facilities or operations of the Joint Utilities. In addition, the Joint Utilities will comply with all applicable current safety laws, rules and procedures, including their respective internal policies. Therefore, the Joint Utilities request that the Commission act expeditiously on this Amended Application.

e. Rule 2.2 – Articles of Incorporation

A copy of SoCalGas' Restated Articles of Incorporation, as last amended, presently in effect and certified by the California Secretary of State, was previously filed with the Commission on October 1, 1998, in connection with A.98-10-012, and is incorporated herein by reference.

A copy of SDG&E's Restated Articles of Incorporation as last amended, presently in effect and certified by the California Secretary of State, was filed with the Commission on September 10, 2014, in connection with SDG&E's Application No. 14-09-008, and is incorporated herein by reference.

A copy of Southwest Gas' Articles of Incorporation with Statement of Conversion, dated January 4, 2017, were filed in Application 18-02-008 and are incorporated herein by this reference.

A copy of PG&E's Amended and Restated Articles of Incorporation, effective June 22, 2020, was filed with the Commission on July 1, 2020, in connection with A.20-07-002, and is incorporated herein by reference.

f. Rule 3.2 Compliance Based on Category

In accordance with Rule 3.2(a)–(d) of the Commission's Rules of Practice and Procedure, the Joint Utilities provide the following information.

i. Rule 3.2(a)(1) – Balance Sheet and Income Statement

The most recent updated Balance Sheet and Income Statements for SoCalGas, SDG&E, PG&E, and Southwest Gas are attached to this Amended Application as Attachments 1, 2, 3, and 4 respectively.

ii. Rule 3.2(a)(2) – Statement of Present Rates

A statement of all of SoCalGas's presently effective rates can be viewed electronically on SoCalGas' website: https://tariff.socalgas.com/regulatory/tariffs/tariffs-rates.shtml.

A statement of all of SDG&E's presently effective rates can be viewed electronically on SDG&E's website: https://www.sdge.com/rates-and-regulations/current-and-effective-tariffs.

A statement of all of Southwest Gas' presently effective rates can be viewed electronically on Southwest Gas' website: https://www.swgas.com/en/california-rates-and-regulation.

PG&E's presently effective gas and electric rates are attached as Attachments 5 and 6 to this Amended Application.

iii. Rule 3.2(a)(3) – Statement of Proposed Rates

The rate changes that will result from this application are described in Attachments 7, 8, 9, and 10 for SoCalGas, SDG&E, PG&E, and Southwest Gas, respectively.

Rule 3.2(a)(4) – Description of Joint Utilities' Property and Equipment

A general description of SoCalGas's property and equipment was previously filed with the Commission on May 3, 2004, in connection with SoCalGas's A.04-05-008, and is incorporated herein by reference. SoCalGas's most recent statement of Original Cost and Depreciation Reserve is attached as Attachment 11.

A general description of SDG&E's property and equipment was filed with the Commission on October 5, 2001, in connection with Application 01-10-005, and is incorporated herein by reference. SDG&E's most recent statement of Original Cost and Depreciation Reserve is attached as Attachment 12.

A general description of Southwest Gas' property and equipment was filed with the Commission on August 30, 2019, in connection with Southwest Gas' Application 19-08-015. Southwest Gas' most recent statement of Original Cost and Depreciation Reserve is attached as Attachment 13.

A general description of PG&E's Electric Department and Gas Department properties, their original cost, and the depreciation reserve applicable to such property and equipment, was filed with the Commission on March 10, 2022, in A.21-06-021, and is incorporated herein by reference.

iv. Rules 3.2(a)(5) and (6) – Summary of Earnings

A summary of earnings for SoCalGas, SDG&E, and Southwest Gas are included herein as Attachments 14, 15, and 16 respectively.

A summary of PG&E's recorded 2022 revenues, expenses, rate bases and rate of return was filed with the Commission on July 28, 2023, in A.23-07-012 and is incorporated herein by reference.

v. Rule 3.2(a)(7) – Depreciation

For financial statement purposes, SoCalGas and SDG&E computed depreciation of utility plant on a straight-line remaining life basis at rates based on the estimated useful lives of plant properties. For federal income tax accrual purposes, SoCalGas and SDG&E generally compute depreciation using the straight-line method for tax property additions prior to 1954, and liberalized depreciation, which includes Class Life and Asset Depreciation Range Systems, on tax property additions after 1954 and prior to 1981. For financial reporting and rate-fixing purposes, "flow through accounting" has been adopted for such properties. For tax property additions in years 1981 through 1986, SoCalGas and SDG&E have computed their tax depreciation using the Accelerated Cost Recovery System. For years after 1986, SoCalGas and SDG&E have computed their tax depreciation using the Modified Accelerated Cost Recovery Systems and, since 1982, have normalized the effects of the depreciation differences in accordance with the Economic

Recovery Tax Act of 1981 and the Tax Reform Act of 1986.

For financial statement purposes, Southwest Gas computed depreciation of utility plant on a straight-line remaining life basis at rates based on the estimated useful lives of plant properties. For federal income tax accrual purposes, Southwest Gas generally computes depreciation using the Class Life and Asset Depreciation Range Systems, on tax property additions after 1954 and prior to 1981. For tax property additions in years 1981 through 1986, Southwest Gas has computed their tax depreciation using the Accelerated Cost Recovery System. For years after 1986, Southwest Gas has computed their tax depreciation using the Modified Accelerated Cost Recovery Systems and, since 1982, have normalized the effects of the depreciation differences in accordance with the Economic Recovery Tax Act of 1981, the Tax Reform Act of 1986 and the Tax Cuts and Jobs Act of 2017.

PG&E's statement of the method of computing the deprecation deduction for federal income tax purposes was filed with the Commission on July 22, 2022, as Attachment E to PG&E's 2023 GRC Phase I Application, A.21-06-021, and is incorporated herein by reference.

vi. Rule 3.2(a)(8) – Proxy Statement

A copy of SoCalGas' most recent proxy statement sent to all shareholders of SoCalGas' parent company, Sempra, dated March 29, 2022, was provided to the Commission on April 13, 2022, and is incorporated herein by reference.

A copy of the most recent proxy statement sent to all shareholders of SDG&E's parent company, Sempra, dated March 29, 2022, was provided to the Commission on April 13, 2022, and is incorporated herein by reference.

A copy of Southwest Gas' most recent proxy statement, dated March 21, 2023, is included herein as Attachment 13.

PG&E's most recent proxy statement dated April 6, 2023, was filed with the Commission on May 2, 2023, in A.23-05-005, and is incorporated herein by reference.

vii. Rule 3.2(a)(10) - Statement re Pass Through to Customers

Any rate increase resulting from approval of the balancing accounts requested herein will not solely reflect pass through to customers of increased costs to the Joint Utilities for the services or commodities furnished by them.

viii. Rule 3.2(b) – Notice to State, Cities, and Counties

SoCalGas, SDG&E, and PG&E will, within 20 days after filing this Amended Application, mail a notice to the State of California and to the cities and counties in their service territories.

ix. Rule 3.2(c) – Newspaper Publication

SoCalGas, SDG&E, and PG&E will, within 20 days after filing this Amended Application, publish in newspapers of general circulation in each county in their service territories notice of this Application.

x. Rule 3.2(d) – Bill Insert Notice

SoCalGas, SDG&E, and PG&E will, within 45 days after filing this Amended Application, provide notice of this Amended Application to their customers along with the regular bills sent to these customers that will generally describe the proposed rate changes addressed in this Amended Application.

g. **Rule 1.9 – Service**

The Joint Utilities are serving this Amended Application on all parties to A.20-11-004 (original application to establish hydrogen blending demonstration program), R.13-02-008 (Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions), R.19-09-009 (Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies), and R.20-01-007 (Order Instituting Rulemaking to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in CA & perform Long-Term Gas System Planning).

XI. CONCLUSION

For the reasons described above and in the testimony supporting this Amended Application, the Joint Utilities respectfully request that the Commission:

- Authorize the Joint Utilities to establish and implement each of their proposed Projects, including entering into the necessary contracts and/or agreements with third parties to implement the Projects;
- Authorize the Joint Utilities to recover all costs related to their respective Projects as set forth in the supporting testimony;

- Authorize the creation of two-way balancing accounts to track and recover the costs to implement each Project;
- Authorize the creation of subaccounts to record each utility's proportional share of the cost allocation for any shared plans, studies, and reporting required by D.22-12-057; and
- Granting of such other relief as is necessary and proper.

Respectfully submitted,

By: *___/s/ Gina Orozco___*
GINA OROZCO

Vice President – Gas Engineering and System Integrity for:

SOUTHERN CALIFORNIA GAS COMPANY and
SAN DIEGO GAS & ELECTRIC COMPANY

By: *___/s/ Ismael Bautista, Jr.___*
Ismael Bautista, Jr.

ISMAEL BAUTISTA, JR.

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March 1, 2024

OFFICER VERIFICATION

I am an officer of Southern California Gas Company and am authorized to make this verification on its behalf. The matters stated in the foregoing Application are true to my own knowledge, except as to matters that are stated therein on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 1st day of March 2024, at Los Angeles, California.

By: *\/s/ Gina Orozco*
Gina Orozco

Vice President – Gas Engineering and System Integrity for:

SOUTHERN CALIFORNIA GAS COMPANY

I am an officer of San Diego Gas & Electric Company and am authorized to make this verification on its behalf. The matters stated in the foregoing Application are true to my own knowledge, except as to matters that are stated therein on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 1st day of March 2024, at San Diego, California.

By: */s/ Miguel Romero*
Miguel Romero

Chief Commercial Officer for:

SAN DIEGO GAS & ELECTRIC COMPANY

I am an officer of Southwest Gas Corporation and am authorized to make this verification on its behalf. The matters stated in the foregoing Application are true to my own knowledge, except as to matters that are stated therein on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 1st day of March 2024, at Las Vegas, Nevada.

By: */s/ Jerome Schmitz*
Jerome Schmitz

Vice President/Engineering Staff for:

SOUTHWEST GAS CORPORATION

I am an officer of Pacific Gas and Electric Company and am authorized to make this verification on its behalf. The matters stated in the foregoing Application are true to my own knowledge, except as to matters that are stated therein on information and belief, and as those matters, I believe them true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 1st day of March 2024, at San Francisco, California.

By: */s/ Christine Cowsert*
Christine Cowsert

Sr. Vice President, Enterprise Technology Modernization for:

PACIFIC GAS AND ELECTRIC COMPANY

Application: A.22-09-006
Witness: B. Waymire
Chapter: 2

PREPARED DIRECT TESTIMONY OF

BLAINE WAYMIRE

ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY

(SOCALGAS'S HYDROGEN BLENDING DEMONSTRATION - OPEN SYSTEM PROJECT)

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

March 1, 2024

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CHAPTER 2

PREPARED DIRECT TESTIMONY OF BLAINE WAYMIRE

(SOCALGAS'S HYDROGEN BLENDING DEMONSTRATION - OPEN SYSTEM PROJECT)

I. PURPOSE

The purpose of this prepared direct testimony on behalf of Southern California Gas Company (SoCalGas) is to provide the technical objectives, need, project implementation detail, and costs for a second proposed SoCalGas hydrogen blending demonstration project, which will be held in an open portion of the natural gas distribution system (Open System Project). This testimony will focus on a description of the Open System Project and how it will help inform a future hydrogen injection standard and support SoCalGas's, San Diego Gas & Electric Company's (SDG&E), Pacific Gas and Electric Corporation's (PG&E), and Southwest Gas Corporation's (Southwest Gas) (collectively, the Applicants) focus on safety, system integrity, and reliability, as well as adhering to the project requirements set out by California Public Utilities Commission (Commission) Decision (D.) D.22-12-057 and guidance under D.21-07-005. This testimony will address the Open System Project's purpose, how the live blending data collected will provide key technical, operational, and safety information to support a future hydrogen injection standard, how SoCalGas will collaborate with the City of Orange Cove, California, the other investor-owned utilities (IOUs), and other relevant stakeholders to integrate data collected from the demonstration projects and prevent duplicative efforts, and provide project cost estimates.

The purpose of this Open System Project is to demonstrate operational, live blending and collect system performance data for blending from 0.1% to 5% hydrogen gas by volume[1] in an open portion of a medium pressure[2] plastic and steel distribution pipeline system. Project data will inform the feasibility of developing a hydrogen injection standard for distribution systems that serve existing natural gas-powered appliances found in residential and commercial facilities.[3]

[1] In this testimony, all blend percentages mentioned are by volume.

[2] Medium pressure is defined as 60 pounds per square inch gauge or lower.

[3] The City of Orange Cove makes up approximately 2,000 residential meters and approximately 100 commercial meters on SoCalGas's system.

Testing on an open portion of a distribution system in SoCalGas's territory is necessary because it will emulate behavior of what occurs when hydrogen is blended into a broader pipeline distribution network and served to a vast number of customers. This is important because it will give a closer snapshot of what hydrogen blending across the larger distribution system might look like and provide meaningful data on widespread hydrogen blending. Additionally, the City of Orange Cove hosts various mixed material gas pipeline and vintages with steel, polyethylene (PE), and Aldyl-A pipeline materials. The Open System Project will showcase blending in various pipeline materials at lower concentrations of hydrogen and complements the projects proposed by SDG&E and Southwest Gas, which occur in an isolated portion of the distribution system, and by PG&E, which occurs in an isolated transmission test loop.[4] Demonstrating behavior of hydrogen blends in live operation across an open branch of the greater distribution system provides a unique opportunity to prove the use case of hydrogen blending at a greater scale.

SoCalGas is pleased to work with the City of Orange Cove, an agriculture community located along the eastern foothills of the Sierra Nevada Mountains and home to approximately 10,000 residents and various local businesses.[5] The City of Orange Cove's Mayor Pro Tem expressed excitement for the potential of a hydrogen blending demonstration project in his city, stating, "I'm excited about that; that they want to do something here in our city."[6] The city enjoys a year around growing season for hundreds of acres of orange and lemon citrus fruit, with major packing house operations surrounding the community.[7] In addition to the strong collaboration with the City of Orange Cove, the community was identified as an ideal candidate to receive the hydrogen blend from a technical feasibility standpoint due to the variety of pipeline materials it contains as indicated above. The community also has one natural gas feed coming into it, which would allow for ample control of the hydrogen blend that it receives because there will be only one point of interconnection to the pipeline system.

[4] *See* Direct Testimonies of Pooyan Kabir (Chapter 3), Kevin Lang (Chapter 4), and Danielle Mark (Chapter 5).

[5] City of Orange Cove, *About Orange Cove, available at*: https://cityoforangecove.com/about-orange-cove/.

[6] Mid Vally Times, *SoCalGas presents hydrogen blending to Orange Cove* (November 13, 2023), *available at*: https://midvalleytimes.com/article/news/2023/11/13/socalgas-presents-hydrogen-blending-to-orange-cove/.

[7] *Id.*

The Open System Project will provide validation on a local system of a strong base of previous analysis, testing, and field demonstrations including comparable field testing performed by ATCO for their hydrogen blending demonstration in Fort Saskatchewan, Canada.[8] The Open System Project will blend into an entire community just downstream of a SoCalGas regulator station so that the entire area served by a regulator station receives the hydrogen and natural gas blend in order to simulate blending into an "open portion" of the distribution system. The project will begin with an initial hydrogen blend level of 0.10% and gradually ramp up to 5% based on safety and technical feasibility validated with testing throughout the project duration. This demonstration will provide valuable operational data that will support the development of a hydrogen injection standard for gas distribution systems. Meanwhile, the projects hosted by SDG&E, Southwest Gas, and PG&E will aim to inform and support the development of a hydrogen injection standard for higher blends of hydrogen in distribution and transmission systems.

II. PROJECT DESCRIPTION

In this section, SoCalGas outlines the details of the proposed Open System Project focused on blending hydrogen into an open portion of a mixed material natural gas distribution system. To demonstrate blending into an open system, or an open portion of the distribution system, blending will occur just downstream of a regulator station that feeds an entire community.

SoCalGas intends to blend from 0.1% to 5% hydrogen by volume into the City of Orange Cove's gas infrastructure. The project will demonstrate hydrogen blending under live operational conditions in plastic and steel pipeline infrastructure across an open portion of the distribution system, and also provide useful data on impacts to end use equipment in various customer types.

The pipeline system supplying the City of Orange Cove will be unaltered, with the exception of a new pipeline that will be installed directly downstream of the regulator station. This pipeline will divert the gas coming out of the regulator station to the blending skid, where it will be blended with hydrogen to the designated blend percentage and reintroduced into the associated pipeline system. The hydrogen blend will be used for residential natural gas

[8] ATCO, *Fort Saskatchewan Hydrogen Blending Project, available at:* https://gas.atco.com/en-ca/community/projects/fort-saskatchewan-hydrogen-blending-project.html.

equipment in homes across the City of Orange Cove and commercial gas equipment in the businesses of the City of Orange Cove. Equipment examples consist of, but are not limited to, water heaters, furnaces, common cooking appliances, and commercial space and water heating. To blend up to 5% hydrogen by volume to the entire community, SoCalGas utilized historical consumption of natural gas for the community based on the years 2021-2023 to size equipment capable of meeting the demand for the designated hydrogen blend. The Open System Project is proposed to be implemented over 18 months during which SoCalGas to collect data and evaluate for seasonal demand conditions. The hydrogen blend volume will be gradually increased over the course of the demonstration through frequent testing of gas quality, leakage, end-use equipment, pipelines, and pipeline components.

The Open System Project will be divided into four chronological phases with defined budgets for each phase. The Phases are briefly summarized in Table 1 and defined in detail in subsequent testimony.

Table 1: Summary of the Open System Project Phases

Phase & Activity	Description	Estimated Duration
0. Pre-development	All efforts supporting this Amended Application submittal are considered “Pre-development.” Upon Commission approval, the project will move on to subsequent phases	Pre-application submittal
1. Design, Construction, and Commissioning	Hydrogen production and blending equipment is designed; detailed safety and feasibility analyses are performed. Stakeholder engagement will be conducted throughout the project’s lifespan. Following design and feasibility, equipment is procured, constructed, and commissioned; pre-demo equipment and pipeline system inspections and any necessary remediation are conducted	18 months
2. Demonstration and Data Collection	Hydrogen is blended in system on a data analysis schedule; data is collected; periodic inspection of equipment and pipelines; test pipelines and components pre-, during, and post-hydrogen blend exposure	24 months (18 months live blending and 6 months asset inspection and validation)
3. Decommissioning, Equipment Removal, and System Restoration	Potential removal of hydrogen equipment	6 months

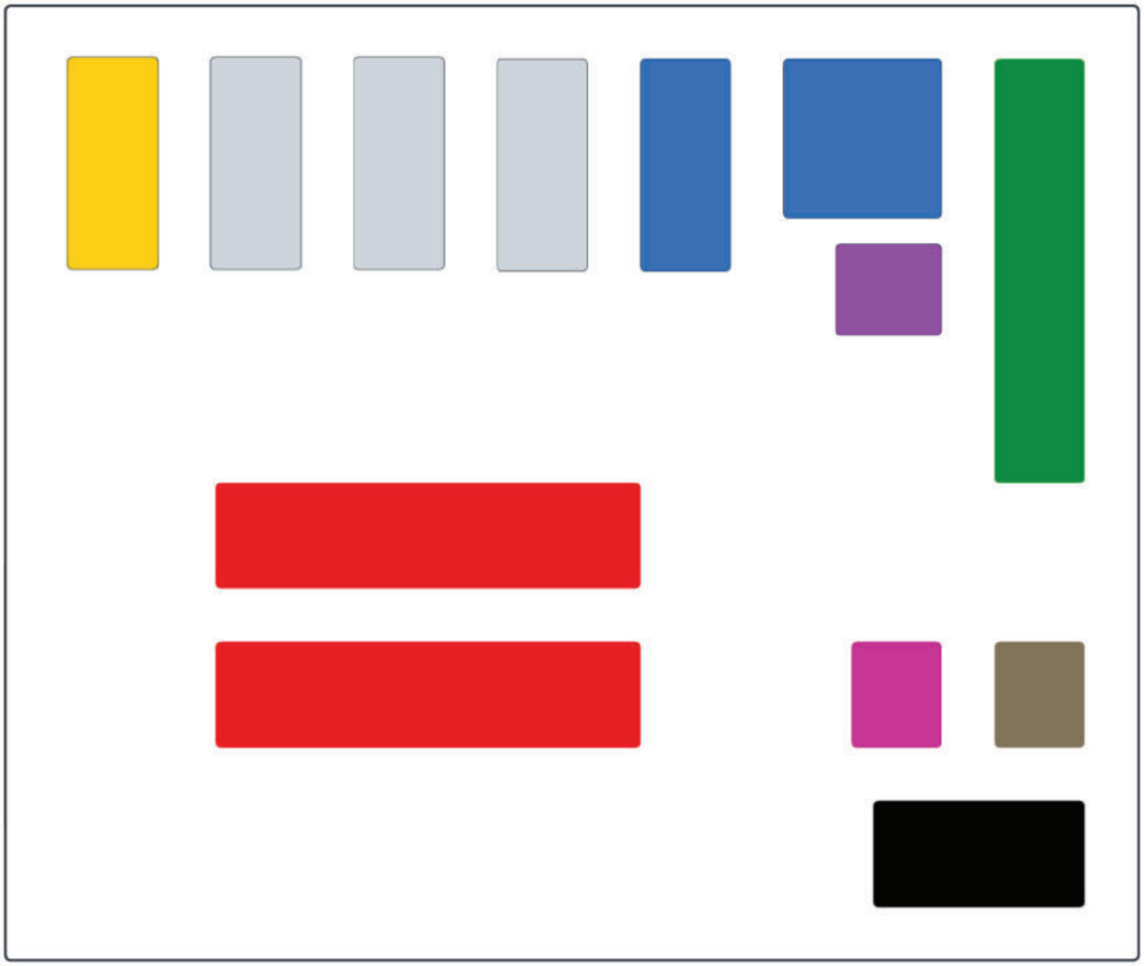
4. Data Analysis and Dissemination	Data from pilot is analyzed and a public report will be released	9 months

Figures 1 to 3 show the potential project site layout, plot plan in the City of Orange Cove, and the pipeline schematic to introduce the hydrogen blends. The proposed site is at the southwest corner of Jacobs Avenue and South Avenue, situated diagonally across the intersection from SoCalGas's regulator station. The project site and layouts shown in Figures 1 to 3 provide the technical, spatial, and construction feasibility in order to serve blends to the community served by SoCalGas's regulator station.

Figure 1: Proposed Site Layout

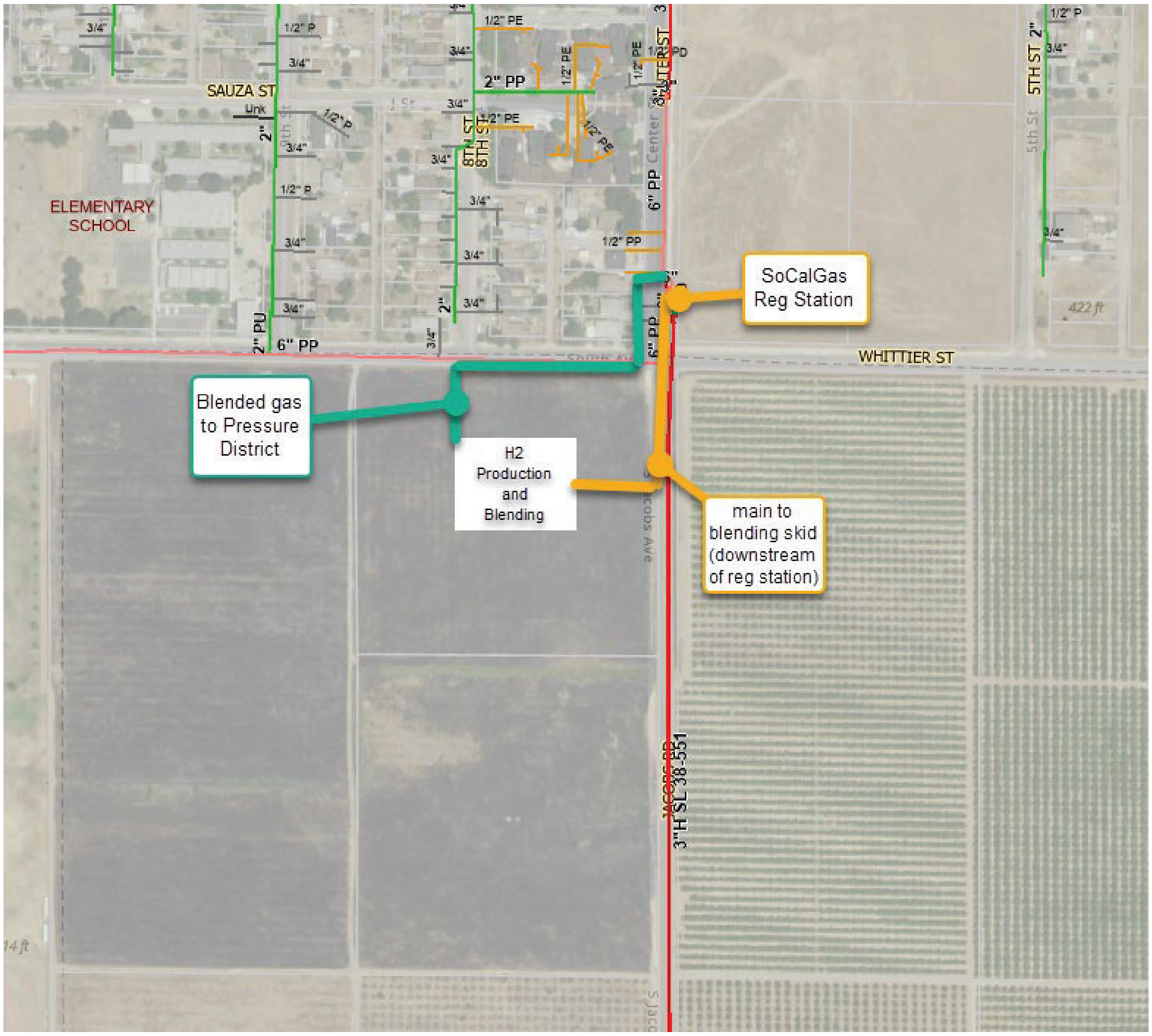
The equipment layout and separation distances are planned to occupy an area of 107 feet by 90 feet. This area may decrease as the design specifications mature. The figure illustrates the proposed site layout with the safe distances, as well as equipment sizes. The proposed site would be 100 feet from intersection and 50 feet from the road on each side. The grey shading in Figure 2 represents a proposed solar array on the plot.

Figure 2: Preliminary Project Plot Plan



Equipment Type	Color
Water Storage and Purification Systems	Blue
Electrolyzer	Green
SCADA Building	Yellow
Bulk Hydrogen Storage	Red
Hydrogen Compressor	Pink
Chiller Unit	Purple
Gas Composition Analyzer	Brown
Blending Skid	Black
Battery Energy Storage	Grey

Figure 3: Routing of Pipelines



The proposed Open System Project aligns with recommendations from the University of California, Riverside's (UC Riverside) Hydrogen Blending Impacts Study (UC Riverside Study),[9] the requirements set out in D.22-12-057, and guidance in D.21-07-005. One of the key directives from D.22-12-057 is that the proposed project should evaluate "… hydrogen injection at blends between 0.1% and 5%."[10] The Commission's Energy Division later clarified that the lower-level blends should be performed in an open portion of the distribution system.[11] The project will follow the Commission's recommendation and collect operational data on an open

[9] UC Riverside, *Hydrogen Blending Impacts Study* (July 2022); *available at* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.
[10] D.22-12-057 at 69 (OP 7.d).
[11] In a virtual meeting held in January 2023, the Commission's Energy Division clarified its expectation that lower blend percentages would be evaluated in an open portion of the distribution system.

pipeline system that feeds residential and light commercial gas equipment typically found in California.

A. Phase 0: Pre-Development

All efforts supporting this Amended Application filing are considered "Pre-development." Upon Commission approval, the Open System Project will proceed to subsequent phases.

To develop this Amended Application, SoCalGas collaborated with personnel from the City of Orange Cove to identify a preferred preliminary site and scope. The proposed site selection was made with input from city personnel and considered the following factors:

- Pipe properties and operational history
- Proximity to SoCalGas regulator station
- End-users and equipment
- Constructability (adequate space)
- Safety
- Summer load and yearly load (sufficient flow to blend)
- Time to survey pipeline system and load (pre-, during, and post-demonstration)
- City personnel support

B. Phase 1: Design, Construction, and Commissioning

Detailed engineering design and an independent safety review will be undertaken to verify the feasibility of the proposed scope and location. The preliminary project design will be finalized with a third-party expert as required. This third-party expert will be involved in every step of the process to provide input on testing protocols and project design.

During the construction period, the site will be prepared and equipment installed. Construction will be coordinated with city personnel. The Open System Project will include the following major equipment:

- **Electrolyzer**: Hydrogen used in this demonstration will be produced onsite via a dedicated electrolyzer. The electrolyzer will produce hydrogen using water and electricity and will be sized to blend up to 5% hydrogen into the city of Orange Cove based on historical usage for the community. The electrolyzer will use electricity from installed solar and locally sourced water to create and store hydrogen onsite. Wherever possible, the water used will come from a non-potable water source so that there is minimal impact to water use from the electrolyzer.

- **Hydrogen Blending Skid**: A blending skid will be required to inject hydrogen into the pipeline system. SoCalGas will collaborate with a blending skid vendor to design a blending skid suitable for the project. Commissioning blending skids for the demonstration projects will be key to learn about sizing and operation of these units that will likely be utilized for injection throughout the California system when a final hydrogen injection standard is established.
- **Hydrogen Storage Vessel**: A hydrogen pressure vessel will be installed to meet sufficient hydrogen supply so that hydrogen blending levels are consistent and allow for efficient operation of the electrolyzer equipment.
- **Solar Array**: Approximately 6.5 acres of solar array will be installed over the majority of the plot provided where the equipment is sited to produce the electricity required for operation of the electrolyzer and associated equipment needed for hydrogen production. Six-and-a-half (6.5) acres translates to approximately 1.1 MW of power, which will be coupled with onsite energy storage to create a microgrid.[12] The microgrid will serve as the primary power source for the hydrogen production and blending equipment and can provide approximately 5 days of independent power operation, dependent on solar operating conditions. The solar array is sized to operate the full facility with supplemental power from the electric grid.
- **Battery Storage:** Approximately 9 MWh of battery energy storage will be installed to supplement the solar energy for the hydrogen production and auxiliary equipment. The battery storage can provide approximately 1.5 days of energy supply, in the event the solar is completely unavailable and the local electric utility is unable to supply back up power.

[12] Calculations performed using NREL's Land Use Requirements for Solar Plants in the United States. Ong, S., Campbell, C., Denholm, P., Margolis, R., and Heath, Gavin, *Land-Use Requirements for Solar Powered Plants in the United States* (June 2013), *available at*: https://www.nrel.gov/docs/fy13osti/56290.pdf.

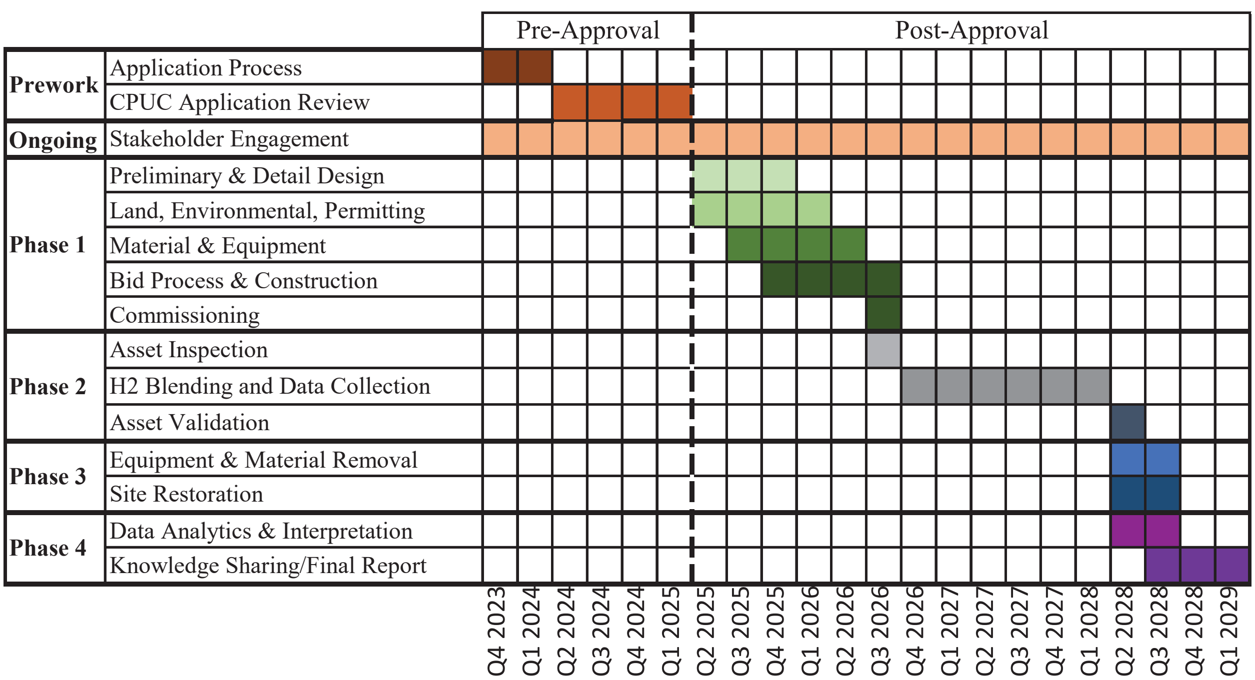
- **Water Storage and Cleanup:** Water will be sourced from sustainable sources whenever possible, and stored onsite using water storage and purification systems so that there is sufficient water available for hydrogen production.

Additional equipment and instrumentation that will be utilized are Supervisory Control and Data Acquisition (SCADA) RTU, chiller, compressor, de-ionizer (DI), gas analyzers, gas detectors, fire detectors, pressure transmitters, and temperature transmitters. A minimal amount of additional plastic pipe will be installed to route the gas downstream of the regulator station to the blending skid and back to the injection point across the intersection as shown in Figure 3 above.

1. Project Schedule

Table 2 provides an estimated project timeline; however actual timeline and schedule will vary depending on the regulatory process approval. Additionally, lead time for materials and other items may have unforeseeable impacts to project schedule.

Table 2: Estimated Project Schedule



C. Phase 2: Testing and Demonstration

1. Asset Inspection

Prior to the introduction of hydrogen, SoCalGas will conduct an asset review and inspection, and will baseline the demonstration area with regular natural gas. All customer appliances involved in the demonstration in the City of Orange Cove will be offered courtesy inspections to confirm the appliances are in safe working order. Leak surveys will also be performed throughout the community prior to the demonstration to confirm the system is leak tight. Any material repair or replacement needed on SoCalGas's distribution system will be completed prior to injecting hydrogen. Leak surveys will be conducted periodically throughout the demonstration as outlined in Section II.C.2 below.

2. Live Hydrogen Blending and Data Collection

The Open System Project will follow the American Petroleum Institute's Recommended Practice 1173 (API RP 1173) Pipeline Safety Management System (PSMS) Plan-Do-Check-Act approach and (1) translate laboratory research and literature review into actual system operations and cover as many aspects of the technical considerations as possible, (2) confirm understanding of material response, end-use/appliance response, load balancing and blend consistency, and (3) establish protocol for leak detection of the new gas composition (should it occur).[13] The selected project site will allow for these objectives to be achieved physically and operationally. More detail on the PSMS model can be found in the Project Guidance Section (Section III.A) below.

Operational needs include training, additional leak surveying, gas handling, customer service, routine service operations and customer interactions, and emergency response plans. Monitoring during demonstrations will include both system monitoring as well as collecting feedback from customers.

The PSMS "Check: Analysis of Data" step will analyze quantitative and qualitative data and will include an analysis of knowledge gained from any operational changes. Such analysis will inform SoCalGas's recommendations for a statewide hydrogen injection standard. Many of the items below have been assessed through literature review, laboratory testing, and/or vendor

[13] API, *Pipeline Safety Management Systems* (July 2015), *available at*: https://flipflashpages.uniflip.com/3/94156/1106646/pub/html5.html.

surveying. The project will allow for operational review and confirmation of the following within the limitations of the proposed project site:

- Odorant compatibility
- Leak detection equipment compatibility
- Material compatibility
- Component (e.g., fittings, valves) compatibility
- Blend consistency (hydrogen blending injection skid)
- End-use customer appliance compatibility
- Review of Gas Standards for the construction, maintenance and operations of hydrogen blended natural gas system
- Effects on metering,
- Impact on emissions of end-use equipment

Table 3 provides an overview of the type of data that SoCalGas will collect with the project. Each data element serves to validate past hydrogen blending research. Data will be collected prior to, during, and after the project. The data will be analyzed to provide insights to confirm hydrogen blending compatibility of the gas system and end-use equipment. More detailed information on SoCalGas's preliminary data collection plan can be found in Exhibit 2A: Preliminary Data Collection Plan.

Table 3: Preliminary Data Collection Plan

Area	Objective	Frequency	Pre-Demo	During Demo	Post-Demo
Odorant sampling	Confirm hydrogen does not affect efficacy of current natural gas odorant	Monthly	✓	✓	
Leak surveys	Safety checks; repair any leaks prior to starting demo; determine if hydrogen blends affect leakage from fittings, valves, etc.	Quarterly; And as needed for customer service calls	✓	✓	✓

Leak survey equipment	Evaluate performance of new leak survey equipment	Quarterly; And as needed for customer service calls		✓	
Heating value measurement	Monitor and Analyze changes to heating value of gas supplied	Monthly	✓	✓	
Customer meters	Analyze and validate select meter performance	Quarterly		✓	✓
Customer equipment evaluation	Confirm equipment is working properly; validate gas interchangeability	As needed for customer service calls	✓	✓	✓
Customer equipment checks for emissions, including NOx	Perform measurement on emissions from various end-uses in community	To be determined based on comprehensive customer survey	✓	✓	

Table 4 below summarizes the incremental hydrogen blending level schedule. Please note that the actual blend percentage will depend on available hydrogen production and usage demand. This blending schedule aligns with recommendations from UC Riverside Study. Per the study, "[I]t is critical to conduct real world demonstration of hydrogen blending under safe and controlled conditions; and…[a] three year timeline is proposed to complete these activities and the adopt a hydrogen blending standard."[14] Prior to introduction of hydrogen, the demonstration area will be baselined with regular natural gas. Data collection will start with a target blend level of 0.1% and gradually go up to 5%. Six months of data will be collected up to 3% and 12 months of data will be collected for the blends from 4-5%.

Table 4: Estimated Blending Intervals by Increments

% Blending Level	Timeframe
Baselining at 0%	3 months prior to demo
Up to 1%	Months 1 to 3
Up to 3%	Months 4 to 6
Up to 4%	Months 7 to 12

[14] UCR, *Hydrogen Blending Impacts Study* (July 2022) at 4; *available at* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.

Up to 5%	Months 13 to 18

3. Billing Impacts

Since the introduction of hydrogen will have the potential to change the heating value of the gas supplied to the City of Orange Cove, SoCalGas plans to apply retroactive volumetric adjustments to applicable customer bills to accurately charge residents and businesses based on therm usage. SoCalGas intends to address this directly with residents during project implementation.

4. Asset Validation

At the end of the data collection period and hydrogen blending has concluded, leak surveys will be performed to verify no additional leaks have developed. SoCalGas will also confirm with city personnel that there have been no reports of equipment malfunction. SoCalGas and the other IOUs will then work with an independent third-party to gather data collected and disseminate results accordingly.

D. Phase 3: Decommissioning, Equipment Removal, and System Restoration

At the end of Phase 2, and with input from the Commission and the City of Orange Cove, SoCalGas will evaluate whether decommissioning of the equipment is appropriate or if the system should remain in place. After completion of the demonstration, the equipment could be utilized as an injection point for clean renewable hydrogen into the distribution system. Because the project will be designed to produce hydrogen via a microgrid and inject into a portion of the distribution system, the grounds for a hydrogen injection point into the localized gas distribution system are already established and set up. That way, if a hydrogen injection standard is established, there will already be infrastructure in place to begin injecting hydrogen, and a source for producing clean renewable hydrogen. The project is designed with an automatic bypass, so while the hydrogen injection standard is still being determined, the hydrogen blending system can be bypassed and continue to supply natural gas to the community.

In the event that decommissioning shall occur, SoCalGas can remove the hydrogen blending and production equipment and donate the solar array and associated battery energy storage equipment to the city for its own use to provide community benefits as well as save decommissioning costs to ratepayers. SoCalGas would restore the site where the hydrogen equipment was temporarily located as per terms and conditions to be developed with the City of Orange Cove.

Lastly, if none of the assets shall remain in place, SoCalGas can decommission the entirety of the site that was installed during Phase 1 and restore the area to its pre-demonstration condition. Phase 3 cost estimates reflect this conservative scenario in which full decommissioning might occur.

E. Phase 4: Data Analysis and Dissemination

After the demonstration's completion, all of the data collected will be analyzed to guide any operations and maintenance updates needed for hydrogen blending and to support a future hydrogen injection standard in the California gas system. Additionally, any impacts observed will be documented via data collection protocols proposed above and in Exhibit 2A. The Applicants will work accordingly with any selected independent research organizations to provide necessary data and coordinate results that can published for independent evaluation. A report will be published and made available to the general public. A public workshop will be held to share the project's findings.

III. PROJECT GUIDANCE

A. API RP 1173 Pipeline Safety Management System

Safety is at the core of this Amended Application, of paramount importance at SoCalGas, and at the forefront of the Open System Project. The Open System Project utilizes the API RP 1173 PSMS Plan-Do-Check-Act model[15] and is currently in the "Plan" stage. SoCalGas will move into the "Do" stage by initiating the controlled blending demonstration that has been informed by the "Plan" stage. In advance of this Amended Application filing, SoCalGas has continually engaged various stakeholders to garner feedback on the technical details of the proposed demonstration. This way, stakeholder feedback can be accurately incorporated into any operational, safety, or data collection plans. Leading up to and during the "Do" stage, SoCalGas will be establishing operational controls, training to operate with hydrogen blends, documenting and recording data from the demonstration, and continuing to engage with stakeholders, including the communities and end-users. Following this stage, the project leads into the

[15] API, *Pipeline Safety Management Systems* (July 2015), *available at:* https://flipflashpages.uniflip.com/3/94156/1106646/pub/html5.html.

"Check" stage where SoCalGas will learn from the data collected, including utilizing the data for an integrity/risk management analysis. Finally, during the "Act" stage, SoCalGas will be reviewing and updating a potential hydrogen injection standard to allow for blended hydrogen in the distribution system more broadly. SoCalGas will translate the knowledge gained from the project to safety policies and mitigations for the rest of our natural gas distribution system and customer installed equipment. The Plan-Do-Check-Act model is a continuous loop and SoCalGas intends to expand risk modeling, revise standards, policies, and procedures to safely blend hydrogen, and consider future larger scale demonstrations.

B. Overarching Safety Case

Throughout the course of this demonstration, SoCalGas will implement safety protocols in accordance with existing safety codes and standards. SoCalGas's safety efforts to be taken before, during, and after the Open System Project include, but are not limited to:

- Hydrogen safety education for personnel
- Safety assessment for hydrogen storage and hydrogen components
- Offer surveys of end-use customer equipment to confirm behind-the-meter equipment present is free of leakage and is operational
- Conduct pre-, during, and post-implementation leak surveys
- Mitigation measures to prevent hydrogen or hydrogen blends from reaching natural gas storage areas and electrical switching equipment
- Create hydrogen blending specific customer protocols and emergency response plans
- Continuous remote monitoring of hydrogen production, storage, and blending areas
- Automatic and remote shutdown capabilities for the hydrogen production and blending facility in the case an alarm is triggered or a leak is detected
- Offer gas system operational tests and equipment tests (e.g., customer appliance leak, customer appliance flame-out, or pilot light failure), and other operational activities that occur in a natural gas distribution system
- Test existing and new leak survey equipment

C. ATCO's Fort Saskatchewan Hydrogen Blending Project

A separate hydrogen blending demonstration currently underway is ATCO's Fort Saskatchewan Hydrogen Blending Project (ATCO Project) in Fort Saskatchewan, Canada, which is currently demonstrating successful blending up to 5% hydrogen by volume into a subsection of the Fort Saskatchewan natural gas distribution system.[16] According to the ATCO Project website, "About 2,100 customers became the first in the province to use hydrogen-blended natural gas to safely and reliably fuel their homes and businesses."[17] ATCO plans to increase the hydrogen blend in the natural gas system from 5% to 20% to some customers in the project zone in the near future, however, timing for the increased blend is uncertain at this time. As noted by ATCO, this increase will remain safe and reliable.[18]

Building on the success of the ATCO Project and the knowledge gained, SoCalGas proposes to conduct a similar demonstration where hydrogen blends are introduced into a larger subsection of the distribution system. It is important to emphasize that although SoCalGas and other stakeholders can learn from the ATCO Project, there is still a need to conduct a California-specific hydrogen blending demonstration due to potential different designs in pipeline systems and end-use equipment. The operational data that will be collected and analyzed for the gas system and end-use equipment will validate past hydrogen blending research and facilitate future hydrogen blending in the wider gas distribution system in California.

D. Stakeholder Engagement Plan

SoCalGas recognizes that education, outreach, and engagement are important components of the Open System Project, as a broad range of stakeholder groups will be touched by the proposed hydrogen blending demonstration project. Additionally, in accordance with D.22-12-057, Applicants are required to take into consideration the parties' comments and stakeholder input regarding the project.[19]

As such, SoCalGas has worked closely with the City of Orange Cove and various other parties to discuss hydrogen blending and the proposed projects. In order to meet the requirements in D.22-12-057, Ordering Paragraph (OP) 7(h), on June 13, 2023, Applicants hosted a public

[16] ATCO, *Fort Saskatchewan Hydrogen Blending Project, available at:* https://gas.atco.com/en-ca/community/projects/fort-saskatchewan-hydrogen-blending-project.html.
[17] *Id.*
[18] *Id.*
[19] D.22-12-057 at 69 (OP 7.h).

stakeholder workshop to solicit feedback from interested parties. Applicants collectively followed up with any outstanding questions that were not addressed during the workshop so that all feedback was taken into account. To solicit best practices from industry experts and technical stakeholders, on November 6, 2023, Applicants held a technical focused workshop to solicit feedback on their proposed data collection and test plans. Follow-up questions submitted by stakeholders were addressed by the Applicants in a timely manner. Through these various engagement techniques, SoCalGas was able to gather information and inform additional details about the project implementation.

SoCalGas has been specifically proactive in its stakeholder engagement throughout the Orange Cove community. Below is a list of additional activities that SoCalGas has taken to engage stakeholders and solicit feedback:

- Facilitated tours with community leaders, including city officials, first responders and business organizations of SoCalGas's H2 Innovation Experience, providing a real-world example of an existing hydrogen blending facility. The tours enabled SoCalGas to further solicit feedback on the proposed project.
- Completed project briefings with elected officials and presented to the Orange Cove City Council
- Hosted a community engagement meeting in Spanish and English to provide residents with information about the proposed project, solicit feedback from the community, and share valuable information about the bill-assistance programs available to them.[20]

SoCalGas intends to continue working with the City of Orange Cove, which can use this demonstration project in its community as a showcase for advancements in clean energy. SoCalGas will continue performing stakeholder outreach with city staff, residents, businesses, and interested parties after filing of the Amended Application so that the community continues to stay engaged throughout the demonstration period. SoCalGas will keep community members abreast of project updates as additional details become available and project planning unfolds.

SoCalGas will work with the local community to identify relevant community-based organizations (CBO) for project engagement and will hold stakeholder meetings for participation

[20] Mid Valley Times, *SoCalGas presents hydrogen blending to Orange Cove* (November 13, 2023), *available at*: https://midvalleytimes.com/article/news/2023/11/13/socalgas-presents-hydrogen-blending-to-orange-cove/.

of relevant CBOs. CBO collaborations will be formalized through Memorandum of Understandings (MOU). SoCalGas will provide compensation for CBOs based at $150/hour.[21] SoCalGas proposes CBO engagement meetings not to exceed four (4) per year during Phase 1 and an additional three meetings, one at the conclusion of each additional project phase, to share updates, conclusions, and findings. SoCalGas will work with identified CBOs to determine appropriate workshop frequency.

Lastly, SoCalGas will develop a dedicated means of communicating with stakeholders that provides easy accessibility for stakeholders to get in touch about the project.

IV. ORDERING PARAGRAPH 7 COMPLIANCE

D.22-12-057 outlined several requirements for the implementation of hydrogen blending demonstration projects and the Applicants engaged the Commission's Energy Division throughout the development of this Amended Application to address any interpretation issues. Below is a detailed discussion of how SoCalGas's proposed Open System Project complies with OP 7 of D.22-12-057.

A. OP 7a

Ensures the long-term safety of the California pipeline, the prevention of hydrogen leakage, the inclusion of hydrogen monitoring, the consideration of the dilution rate, and the monitoring and reporting of all mechanical characteristics of hydrogen blends in the natural gas pipeline stream

Within the Open System Project, SoCalGas intends to take various steps to maximize safety, prevent hydrogen leakage, monitor hydrogen production and storage facilities, measure the hydrogen blends in the demonstration program, and monitor all mechanical characteristics. As such, SoCalGas will perform enhanced leak detection protocols to verify that the introduction of hydrogen is not compromising the safety of the gas system and associated end-use equipment throughout the duration of the demonstration. As outlined in Section II.C.2, SoCalGas will increase leak testing to a quarterly basis compared to the standard annual frequency. SoCalGas will deploy robust monitoring surrounding the hydrogen production, storage, and blending facilities to detect leakage or issues with the hydrogen equipment. Remote and continuous

[21] This hourly rate is consistent with CBO compensation outlined in SoCalGas Advice No. 6146G; *available at:* https://tariff.socalgas.com/regulatory/tariffs/tm2/pdf/submittals/GAS_6146.pdf.

monitoring on these systems will notify SoCalGas of leakage to the hydrogen facilities and prompt SoCalGas to respond to address any issues as necessary. If an alarm is triggered or leakage is detected in the hydrogen production and storage area, the hydrogen system will go into a shutdown mode, isolating equipment, stopping hydrogen production, and returning the pipeline system to 100% natural gas. A gas measurement analyzer will be installed at the outlet of the blending skid so that the blend percentage introduced into the system is accurate. Additionally, gas sampling will be implemented by taking measurements downstream of the introduction point to monitor the hydrogen blends at select points in the system. SoCalGas will continually monitor the operation of the hydrogen blending, storage, production, and associated electrical and water aspects of the project. SoCalGas intends to perform upfront inspections as well as continuous inspections on various points of this demonstration. Exhibit 2A outlines detailed data collection plans.

B. OP 7b

Prevents hydrogen from reaching natural gas storage areas and electrical switching equipment directly or through leakage

There will be no modifications to the pipeline system, other than the piping installed to divert gas downstream of the regulator station to the associated blending equipment. However, there are no natural gas storage facilities in the area. SoCalGas will install backflow prevention so that no hydrogen blends flow backward into the system upstream of the regulator station. Hydrogen storage, production, and blending equipment will be sited in a plot of land across from SoCalGas's regulator station, and there is no known electrical switching equipment within proximity. The site will be designed in a matter that if any electrical equipment switching equipment were to be present, it will be located in unclassified areas or will be protected by classified enclosures per applicable industry codes and standards. Lastly, independent risk analyses will be performed prior to project implementation and will inform if any unforeseen risks are present regarding a potential for hydrogen to reach natural gas storage or electrical switching equipment. If anything is found during the risk assessment stages, design will be implemented for mitigation.

C. OP 7c

Avoids end user appliance malfunctions

SoCalGas will work with the community, including the business customers, to analyze the various end-uses and make sure there are no known processes that would be impacted by hydrogen blends, even at low percentages. SoCalGas will offer equipment inspections prior to introduction of hydrogen to verify the appliances are in working order and will provide contact information for customers to use should they experience difficulties with their appliances. SoCalGas will work with City staff to ensure that once blending commences, any reports of appliance malfunction are documented and, if necessary, SoCalGas will provide operational support.

Additionally, research shows that common appliances can operate safely with blends above 20% hydrogen. A study from GTI, which tested various partially premixed combustion equipment with no adjustments, has shown that heating equipment "…was successfully operated up to 30% hydrogen-blended fuels."[22] This demonstration is designed to further validate previous research findings.

D. OP 7d

Evaluates hydrogen injection at blends between 0.1 and five percent and five to twenty percent; such evaluations must adhere to approved monitoring, reporting, and long-term impact study in accordance with the approval of the pilot project application, and must include validation programs to confirm performance

The Open System Project will evaluate blends from 0.10 to 5% in an open system. In doing so, it will adhere to approved monitoring and reporting that are in alignment with the UC Riverside Study. Please refer to Section II.C.2 and Exhibit 2A for complete details of a preliminary data collection plan. SoCalGas's proposed Closed System Project, SDG&E's Project, Southwest Gas's Project, and PG&E's project, outlined in Chapters 1, 3, 4, and 5, respectively, will evaluate hydrogen blends between 5% and 20% in closed systems.

E. OP 7e

Specifies the amounts of funding necessary to complete all aspects of the proposal and proposes testing durations adequate to draw meaningful conclusions

[22] Glanville, P., Fridlyand, A., Sutherland, B., Liszka, M., Zhao, Y., Bingham, L., and Jorgensen, K., *Impact of Hydrogen/Natural Gas Blends on Partially Premixed Combustion Equipment: NOx Emission and Operational Performance* (February 24, 2022), *available at:* https://www.mdpi.com/1996-1073/15/5/1706.

A level 5 cost estimate was performed to calculate the funding necessary for all four phases of the Open System Project. Section V summarizes the project cost and WP-2 provides a breakdown of the project cost.

Regarding the demonstration's duration, SoCalGas's Open System Project is in line with other notable hydrogen blending studies and would allow sufficient time to show changes in seasonal gas flows. Testing duration is in line with previous successful demonstrations, such as the HyDeploy Trial Phase I and Phase 2 demonstrations discussed in Chapter 1, that were performed for 18 months[23] and 10 months,[24] respectively. As of February 2022, ATCO's demonstration blending 5% hydrogen into the gas system has been in service for 16 months with plans to increase to 20% hydrogen blends in the near future. The Open System Project will test at a minimum of three (3) months for lower levels and six (6) months for greater hydrogen concentrations. This also aligns with the three-year timeline to adopt a hydrogen blending standard proposed by the UC Riverside Study.[25]

F. OP 7f

Is consistent with all directed courses of action specified in this decision relevant to leakage, reporting, heating value, system safety, environmental considerations, end-use emissions, and all other elements enumerated in this decision

The Open System Project is consistent with all directed courses of action specified in decision D.22-12-057. Details of how SoCalGas's proposed Open System Project addresses all courses of actions has been discussed throughout this prepared testimony and summarized in Table 5 below.

Table 5: Directed Courses of Action in D.22-12-057

Topic	Recap of SoCalGas's Action	Reference
Leakage	The project will be designed to minimize and monitor leakage for hydrogen, methane, and a hydrogen/methane blend with sensors, remote alerts, and other detection systems.	Section II. C.2, IV.A and Exhibit 2A

[23] *See* HyDeploy Phase 1, *available at:* https://hydeploy.co.uk/project-phases/.
[24] *See* Hydeploy Phase 2, *available at:* https://hydeploy.co.uk/project-phases/.
[25] UCR, *Hydrogen Blending Impacts Study* (July 2022), at 4; *available at* https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF.

Reporting	The project's testing program explained will collect and analyze data, and will report the findings of the project. SoCalGas will work with a selected third-party and the Joint Utilities to report on findings.	Section II
Heating value	Gas composition will be monitored after blending skid and at various points downstream of the injection point. Additionally, SoCalGas is evaluating gas chromatographs capable of detecting and measuring hydrogen up to 20 vol%.	Section II.C.2, IV.A and Exhibit 2A
System Safety	Various safety and alert systems are in place so that the project adheres to safety requirements, including a remote monitoring and alarm system. All relevant codes and standards will be applied.	Section III.B and IV.A
Environmental Considerations	The project will produce important information about the potential for carbon reductions using different blend percentages. Other emissions will be measured. Additionally, solar energy is being procured for production of clean renewable hydrogen throughout the duration of the project. Lastly, non-potable water sources will be utilized where possible.	Section II, II.C.2
End-use Emissions	NOx, CO_2, CO, and Oxygen will be measured from select end-use equipment to monitor the emission performance.	Section II.C.2, Exhibit 2A
Blending Limitations	The project will evaluate hydrogen blending between 0.10% to 5% by volume in an open system as directed in D.22-12-057 and clarified by Energy Division. The open system is a real-world gas distribution network using components of gas distribution pipeline. The project is focused on ensuring the long-term safety of the California pipeline.	Section I, II, IV.D
Additional Consideration	Section IV address how the project is in compliance with the directives of D.22.-12-057.	Section IV

G. OP 7g

Proposes rigorous testing protocols consistent with the UC Riverside Study

The Open System Project is consistent with all directed courses of action specified in the UC Riverside Study as well as actions specified in decision D.22-12-057. Additionally, on November 6, 2023, Applicants sought feedback on their data collection plans from stakeholders, the public, and industry experts in their technical stakeholder workshop. Applicants incorporated feedback from stakeholders into their respective data collection plans.

Rigorous testing protocols proposed and will be further developed to address leakage rates, impacts on end-use appliances, impacts to the existing natural gas pipeline system, impacts on fittings, and other components. Exhibit 2A demonstrates the test plan developed for different aspects of the project.

This filing represents pre-development of the Open System Project. Upon application approval, the Applicants will contract an independent party as directed to finalize a research plan for assessment, measurements, monitoring, and reporting. This plan will consider feedback from the technical workshop held on November 6, 2023, as well as the UC Riverside Study.

H. OP 7h

Takes into account parties' comments and further stakeholder input and includes the opportunity for compensation for parties and for community-based organizations

SoCalGas has and will continue to consider parties' comments and stakeholder input. Refer to Section III.D for more details on SoCalGas's stakeholder engagement activities to date, plans for engagement post-Amended Application filing, and CBO compensation.

Applicants utilized public stakeholder workshops to gather feedback from the public. SoCalGas also worked closely with impacted stakeholders within the City of Orange Cove to take into account feedback from the community. SoCalGas hosted a community engagement event to discuss hydrogen blending demonstrations and field questions from residents. The project will provide educational materials and information sessions to disseminate knowledge on the technology, safety measures, and progress on the project.

I. OP 7i

Proposes a methodology for performing a Hydrogen Blending System Impact Analysis that can ensure that any hydrogen blend will not pose a risk to the common carrier pipeline system

This System Impact Analysis would be a checklist for Joint Utilities and potential third parties connecting to the gas system to use to confirm the common carrier pipeline system will remain safe should a hydrogen injection standard be established.

The Joint Utilities propose developing a methodology for performing the Hydrogen Blending System Impact Analysis upon completion of the projects. The proposed methodology will provide a framework so that hydrogen blends do not compromise gas system integrity, safety, or impact end-use equipment.

The methodology will benefit from using the data collected from the demonstration projects. The proposed methodology for hydrogen blending will follow a similar framework as a biomethane interconnection agreement. The framework will include, but will not be limited to:

- Identification of downstream systems.
- Potential materials.
- Operating pressures.
- Equipment (e.g., valves, meters, etc.).
- Review of pipeline history and end-use equipment.
- Any further analysis that is deemed necessary by the interconnecting utility.

J. OP 7j

Includes new or revised heating values and discusses whether heating values would be modified through the use of propane or other means and whether such modifications to heating value can be done safely

Propane or other means will not be used to supplement heating values during the demonstration. The composition of the blended gas will be measured at the outlet of the blending skid and also downstream of the point of injection. This will inform any impacts to heating value at the point of injection and also downstream at strategically selected customer meter set assemblies. Specific information is detailed in Section II.C.2 and impacts to bills are discussed in Section III.C.3.

K. OP 7k

Demonstrates the ability to reliably detect leakage of any hydrogen, methane, or hydrogen/methane blends and describes rigorous hydrogen leak testing protocols that are consistent with leak testing and reporting elements identified in the University of California at Riverside's 2022 Hydrogen Blending Impacts Study, identifies and addresses the comments presented by parties in this proceeding regarding leak issues, *and identifies and addresses the comments presented by workshop stakeholders in this proceeding regarding leak issues*

The Open System Project will include procedures to monitor, identify, and quickly repair leaks to minimize safety risks, including appropriate methods for prompt and reliable leak detection, such as the use of odorant. First, the project will utilize the appropriate design and construction standards, as well as operating gas standards within the designed parameters to minimize the risk of hydrogen leakage. In addition, continuous monitoring of the hydrogen storage and production facilities will be deployed to detect leakage. Also, more frequent leak detection will be utilized through the duration of the project for the blended gas lines and customer equipment. Instrumentation systems will be utilized to measure performance of the system, including temperature, pressure, and gas quality. More information can be found in Section II.C.2, IV.A and Exhibit 2A.

L. OP 7l

Contains an independent research plan for assessment, measurement, monitoring, and reporting through an independent party, which must be engaged in such activities during the development, construction, operational life, and decommissioning of the pilot project

Upon approval of this Amended Application, Applicants will issue a request for proposals (RFP) to solicit competitive bids from an independent party or parties to complete the independent research plan. Given the differences in demonstration projects, different entities might be contracted for development of the research plan. The application phase of the project is pre-development, and therefore the cost of the independent party involvement will be assessed and recovered after the Commission’s decision on the Amended Application through a subaccount.

V. COST ESTIMATES

An unloaded direct cost estimate is provided in Table 6 below. The unloaded direct cost includes all anticipated expenses, with contingency, for the entirety of the Open System Project. The costs are based on a level 5 estimate and shown in 2023 dollars. Please see WP-2 for the detailed breakdown of cost estimates by project phase. Details on revenue requirements are described in the Direct Testimony of Nasim Ahmed and Marjorie Schmidt-Pines (Chapter 6).

Table 6: Unloaded Direct Cost Estimate

2025	2026	2027	2028	Total
$34,366,986	$11,709,582	$966,419	$1,371,045	$48,411,032

VI. CONCLUSION

A live hydrogen blending demonstration is the next critical step to develop a hydrogen injection standard for California. SoCalGas's proposed Open System Project will provide the necessary operational and material data to support such a standard for using the larger distribution gas system to transport natural gas and hydrogen blends. SoCalGas and the City of Orange Cove are looking forward to taking this next step to help California achieve its decarbonization goals.

This concludes my prepared direct testimony.

VII. QUALIFICATIONS

My name is Blaine Waymire. I am employed at SoCalGas as a Project Manager in the Gas Engineering and System Integrity organization. Currently, I lead the Hydrogen Blending Strategy Team's planning for live hydrogen blending demonstrations and regulatory applications. Prior to this, I have held positions within SoCalGas including Sr. Distributed Energy Resources Advisor and Sr. Account Executive, with various engineering analysis and regulatory responsibilities. I have been employed at SoCalGas since May 2012. I hold a Bachelor of Science degree in Mechanical Engineering from California State University, Long Beach. I am a licensed Professional Engineer in the State of California.

MEDIA CONTACT
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Application Seeks to Further California's Efforts to Develop Hydrogen Blending Standard

Hydrogen blending has been identified by the State of California as an important decarbonization tool to help meet its ambitious climate goals

LOS ANGELES – March 1, 2024 – Southern California Gas Co. (SoCalGas) today, along with three other California utilities, filed an application with the California Public Utilities Commission (CPUC) to develop a series of projects that demonstrate blending clean hydrogen into the natural gas system is a safe and effective way to reduce greenhouse gas emissions, improve air quality and begin to scale up hydrogen as laid out in California's climate plan. The application is in furtherance of the CPUC's direction that gas utilities establish hydrogen blending demonstration projects in support of a safe hydrogen injection standard.

California has identified clean renewable hydrogen as a key tool in its ambitious climate goals, with Gov. Gavin Newsom calling it "an essential aspect of how we'll power our future and cut pollution." The blending of hydrogen into the natural gas system specifically has been identified in the California Air Resources Board's 2022 Scoping Plan for Achieving Carbon Neutrality as a tool that can help "reduce demand for fossil energy and GHGs, and improve air quality." In February, the California Energy Commission (CEC) released its 2023 Integrated Energy Policy Report which concluded that California should support efforts to assess hydrogen storage and delivery approaches, including blending into existing gas infrastructure, to help address the state's climate challenges.

"More than two decades of research and real-world experience in the U.S. and abroad shows that blending hydrogen into natural gas infrastructure is a safe and proven way to deliver cleaner fuel to customers," said **Neil Navin, SoCalGas Chief Clean Fuels Officer**. "These demonstration projects are an important step for us to adopt hydrogen blending statewide, which has the potential to be an effective way to replace fossil fuels and create significant demand for the production of clean hydrogen at the scale identified by the California Air Resources Board as necessary for our energy transition."

Hydrogen has been safely and reliably utilized around the world for decades. Hawai'i Gas, which has been using hydrogen in its fuel mix for a half-century, has more than 1,100 miles of pipelines that transport up to 15% hydrogen, serving homes, restaurants, and businesses. Other countries with hydrogen blending projects include Belgium, Canada, Denmark, France, Germany, Italy, and the United Kingdom. For example, in Canada since October 2022, ATCO has been safely blending 5% hydrogen into the Fort Saskatchewan natural gas distribution system, serving some 2,100 customers, with plans to increase the blend to 20% hydrogen.

In line with the state's climate goals and in response to the CPUC's directive, SoCalGas is proposing two demonstration projects that would begin blending amounts as low as 0.1% hydrogen into isolated sections of the natural gas system and incrementally increase the hydrogen concentrations based on safety and technical feasibility testing throughout the demonstrations. One project would serve the University of California, Irvine's (UCI) Anteater Recreation Center and another would serve residents and businesses in the City of Orange Cove. SoCalGas will employ extensive safety measures on both projects that include leak surveys and detection technology, safety assessments of hydrogen storage and components, end-use equipment surveys, and education and training.

The partnerships with UCI and Orange Cove are part of a joint hydrogen blending demonstration application with San Diego Gas & Electric Co. (SDG&E), Pacific Gas and Electric Co. (PG&E) and Southwest Gas Corp. filed Friday with the CPUC. The CPUC's decision on the utilities' application could be decided as early as next winter.

[UCI QUOTE HERE]

"We appreciate SoCalGas' selection of Orange Cove for the hydrogen blending project. The City Council is pleased to support this project, which has the potential to transform the future of Orange Cove and the State of California," said **Orange Cove Mayor Guerra Silva**. "We are delighted to begin this partnership and look forward to its positive impact on this small but innovative community."

As hydrogen gas is made up of carbon-free molecules, blending it with natural gas could lower carbon emissions in various sectors of the economy. For example, at a 20% hydrogen blend by volume, the typical carbon dioxide (CO_2) reduction potential of hydrogen is 6.3%. If California's gas system was 20% hydrogen by volume in 2020, the CO_2 reduction in just one year would have been equivalent to removing 1.52 million gasoline-powered passenger vehicles from the road or replacing about 6% of California's registered automobiles with zero-emission vehicles.

In 2019, the CPUC began working to develop a hydrogen blending standard, prompting SoCalGas and SDG&E to propose blending demonstration projects in their service territories. Since then, the CPUC has worked to gain a better understanding of hydrogen blending in the natural gas system, enlisting the University of California, Riverside to perform a comprehensive study of blending. That study concluded that "it is critical to conduct real world demonstration of hydrogen blending under safe and controlled conditions" in order to close knowledge gaps.

Over the past two decades, SoCalGas has worked on dozens of hydrogen research projects exploring ways to decarbonize industries such as heavy transportation and chemical processes to demonstrate safe hydrogen integration into California's energy systems, including the United States' first successful power-to-gas project in 2016 with UCI, which blended clean hydrogen into a natural gas pipeline to help power parts of the school's campus.

For more information, please visit https://www.socalgas.com/h2blending.

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About SoCalGas

Headquartered in Los Angeles, SoCalGas® is the largest gas distribution utility in the United States. SoCalGas delivers affordable, reliable, and increasingly renewable gas service to over 21 million consumers across 24,000 square miles of Central and Southern California. Gas delivered through the company's pipelines will continue to play a key role in California's clean energy transition—providing electric grid reliability and supporting wind and solar energy deployment.

SoCalGas' mission is to build the cleanest, safest and most innovative energy infrastructure company in America. In support of that mission, SoCalGas aspires to achieve net-zero greenhouse gas emissions in its operations and delivery of energy by 2045 and to replacing 20 percent of its traditional natural gas supply to core customers with renewable natural gas (RNG) by 2030. Renewable natural gas is made from waste created by landfills and wastewater treatment plants. SoCalGas is also committed to investing in its gas delivery infrastructure while keeping bills affordable for customers. SoCalGas is a subsidiary of Sempra (NYSE: SRE), an energy infrastructure company based in San Diego.

For more information visit socalgas.com/newsroom or connect with SoCalGas on Twitter (@SoCalGas), Instagram (@SoCalGas) and Facebook.

This press release contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements are based on assumptions about the future, involve risks and uncertainties, and are not guarantees. Future results may differ materially from those expressed or implied in any forward-looking statement. These forward-looking statements represent our estimates and assumptions only as of the date of this press release. We assume no obligation to update or revise any forward-looking statement as a result of new information, future events or otherwise.

In this press release, forward-looking statements can be identified by words such as "believe," "expect," "intend," "anticipate," "contemplate," "plan," "estimate," "project," "forecast," "should," "could," "would," "will," "confident," "may," "can," "potential," "possible," "proposed," "in process," "construct," "develop," "opportunity," "initiative," "target," "outlook," "optimistic," "poised," "maintain," "continue," "progress," "advance," "goal," "aim," "commit," or similar expressions, or when we discuss our guidance, priorities, strategy, goals, vision, mission, opportunities, projections, intentions or expectations.

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impact of climate and sustainability policies, laws, rules, regulations, disclosures and trends, including actions to reduce or eliminate reliance on natural gas, increased uncertainty in the political or regulatory environment for California natural gas distribution companies, the risk of nonrecovery for stranded assets, and our ability to incorporate new technologies; weather, natural disasters, pandemics, accidents, equipment failures, explosions, terrorism, information system outages or other events that disrupt our operations, damage our facilities or systems, cause the release of harmful materials or fires or subject us to liability for damages, fines and penalties, some of which may not be recoverable through regulatory mechanisms or insurance or may impact our ability to obtain satisfactory levels of affordable insurance; the availability of natural gas and natural gas storage capacity, including disruptions caused by failures in the pipeline system or limitations on the withdrawal of natural gas from storage facilities; and other uncertainties, some of which are difficult to predict and beyond our control.
These risks and uncertainties are further discussed in the reports that the company has filed with the U.S. Securities and Exchange Commission (SEC). These reports are available through the EDGAR system free-of-charge on the SEC's website, www.sec.gov, and on Sempra's website, www.sempra.com. Investors should not rely unduly on any forward-looking statements.

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