REMEDYING UNDERPERFORMING SOLAR PV ASSETS WITH ELECTROLYZER RETROFITS

by

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Abstract

This study explores and quantifies the value of retrofitting utility-scale solar PV-only assets with PEM electrolyzers to produce green hydrogen. Momentum for global hydrogen demand as well as pathways towards decarbonization, are discussed. The study then highlights ways in which green hydrogen electrolyzers could benefit solar PV assets' financial performance. Hypothetical assets within California's CAISO jurisdiction are examined and good candidates for retrofits are identified. Aspects unique to the CAISO market are fleshed-out like The Duck Curve and the high proportion of renewable energy sources. The study uses a Monte Carlo simulation to demonstrate probabilistic combinations of solar PV and green hydrogen lifecycle costs. Use of this framework as a guide would enable project developers and/or investors to facilitate necessary transitions to a reliable, affordable, and clean economy.

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Dedication

To my entire family, both immediate and extended, especially, my sister, Jennifer Corby, PhD, and brother-in-law, Jamie Aroosi, PhD, whose academic journeys inspired me to reach further than I thought possible. To me, this academic work and the curriculum that precedes it represent the acknowledgment of climate change, attribution to human activities, and an end to business-as-usual.

Executive Summary

This study incorporates a great deal of academic knowledge and analytical methodologies accrued through the Energy Policy and Climate (EPC) program at Johns Hopkins University's - Krieger School of Arts and Sciences - Advanced Academic Programs. The curriculum supports the immense backdrop of climate action that precedes this publication. Global consensus for the need to abate climate change, international pledges corroborating such consensus, and the domestic policies that follow have spurred widespread transformation of the global economy. Energy systems writ large must adapt to support decarbonization of other sectors of the economy. One such adaptation is the advent of green hydrogen–that is, hydrogen that was produced using renewable, carbon-free sources of electricity. Once procured, green hydrogen can be integrated into myriad of applications to transcend the traditional compartmentalization of sectoral decarbonization. In assessing the financial viability of green hydrogen, the authors utilized open-source datasets produced by CAISO, solar analysis software, lifecycle financial analysis, and Monte Carlo analysis. Using these techniques, the authors constructed a probabilistic assessment of solar + hydrogen given a wide range of financial inputs. While generalizations about the feasibility of solar + hydrogen are known, this analysis presents novel success at the periphery of conventional wisdom.

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Chapter 1 - Introduction

Section 1.1 The Clean Energy Transition

Decarbonizing the electricity grid is a well-known pathway towards achieving climate goals declared during the internationally recognized Paris Agreement. To achieve these goals, energy portfolios must increasingly consist of low carbon or no-carbon resources. Many countries have already initiated this arduous transition in the electricity sector from fossil-fuel generators to renewable resources. Many obstacles to this transition stem from the intermittency of renewable resources. Although wind and solar assets utilize abundant, carbon-free energy resources, their sources are variable and often irregular. Unlike traditional fossil-fuel generators, renewable generators are non-dispatchable, meaning electricity cannot be generated on-demand.

While the United States has expanded its renewable energy portfolio, on average, approximately half of total installed solar PV capacity installed to-date resides within California (California Energy Commission, 2022). California sits on the cutting-edge of the clean energy transition and serves as the poster-child for many other markets and countries that will soon experience the obstacles that California currently does with regards to the transition. Thus, energy mixes rich in wind and solar sources and the associated electricity grids, like in California, stand to benefit from a broader decarbonization of the overall economy, including transportation, heating, agriculture, buildings, and more.

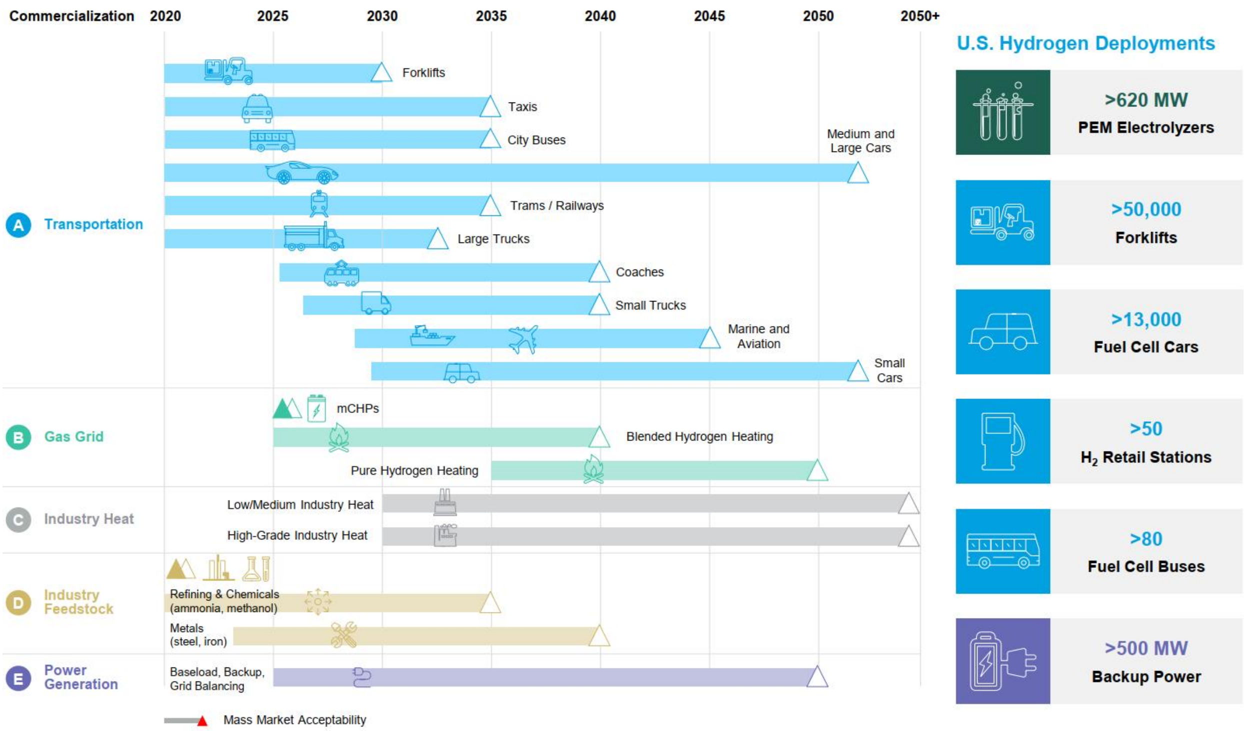
Although California exemplifies American ambition in renewable energy deployment, it suffers from mismatches between electricity supplied and demanded, displacing daily load curves (Jorgenson & Denholm, 2018). This mismatch is a function both spatially, which adds congestion to the constrained transmission grid, and temporally, which adds stress to existing grid-tied assets that must maintain reliability on the grid in real-time. If demand for renewable electricity can be augmented via hydrogen-producing electrolyzers, then operators can restore the balance to the grid and minimize net load (Frankowska, et al., 2022) while simultaneously providing pathways to decarbonize other sectors in the economy.

Section 1.2 The Current and Future State of the Hydrogen Economy

In 2021, hydrogen comprised 2.5% of the final energy demand portfolio (IEA, 2022). By 2050, hydrogen is forecasted to comprise 15-20% of the final energy demand portfolio. In considering pledges to the Paris Agreement, countries around the world have sought to mitigate greenhouse gas emissions (GHGs) from hard-to-abate sectors of the economy. To-date, thirty-five national policies aimed at subsidizing hydrogen procurement have been implemented, illustrating the ambition and willpower to grow the hydrogen economy (Morgan Stanley, 2022). While most of the hydrogen produced today is *Gray*–meaning it was derived from natural gas–a growing share of final energy demand will be *Green* (Frankowska, Mańkowska, Rabe, Rzeczycki, Szaruga, 2022). Hydrogen is anticipated to be a key input across heavy industries and long-haul transportation. (H2 International).

Figure 1 – *Hydrogen Technology*

Clean hydrogen market perspectives



(Morgan Stanley, 2022)

Hydrogen can be repurposed as a feedstock, both directly and indirectly, for other pathways more broadly referred to as Power-to-X (H2 International, 2019). Direct utilization of hydrogen may comprise power-to-heat or power-to-mobility applications like HVAC use and transportation, respectively. Indirect utilization of hydrogen may comprise of power-to-power or power-to-gas like electricity grid storage or feedstocks to industrial processes, like fertilizer and/or syngas production. The flexibility inherent within Power-to-X concepts facilitates opportunities to decarbonize hard-to-abate sectors of the economy. Hydrogen is anticipated to be a key input across long-haul transportation, heavy industries, and fuel-blending (H2 International, 2019).

Transportation. Hydrogen may serve as an alternative fuel for long-haul transport, with several applications to the marine shipping sector. Liquid hydrogen could be used directly as a fuel or converted into either ammonia or methanol for subsequent combustion. In recognition of these possibilities, many public-private partnerships are underway to develop commercially viable shipping vessels. Companies like Shell and Maersk have partnered with Hyundai Heavy Industries and Samsung Heavy Industries to manufacture shipping vessels capable of utilizing hydrogen-based ammonium and methanol fuels. Estimates suggest that large-scale hydrogen and ammonia engines will be commercially available by the mid-2020s. Momentum in favor of decarbonization looks to also promote hydrogen-based aircraft development. Where smaller aircrafts will utilize fuel cell design, medium to long-range aircraft will combust mixtures of hydrogen and carbon dioxide directly. In 2022 alone, airlines, Airbus and Delta, struck deals with Plug Power and Siemens to furnish e-fuels and "Hydrogen Hub" airports (Morgan Stanley, 2022).

Industrial Process. In addition to transportation, many high-temperature industrial processes stand to benefit from incorporating hydrogen. 85% of industrial processes that require direct heat deal with iron, steel, chemical and cement production, each of which significantly contributes to annual GHG emissions. Cement production alone accounts for around 5% of total global GHG emissions (Hasanbeigi, 2021). Although heat is generally considered a waste product of energy transfer, hydrogen provides a low/no-carbon alternative if using infrared and plasma heating. This pathway would require minimal design modifications while also slashing GHG emissions from lifecycle production (Morgan Stanley, 2022).

Hydrogen Blending. While the future of hydrogen looks to grow rapidly and diversify in scope, immediate projects are already underway. A great deal of this deals with hydrogen blending for CCGT units. Hydrogen blending combines natural gas with hydrogen gas prior to combustion and energy generation. Blending reduces tailpipe emissions of generators due to foregone natural gas emissions, although deep decarbonization would be achieved if practitioners utilized green hydrogen. The study conducted by the University of Texas study (2022) concluded that a 5% green hydrogen blend would result in a 2.2% reduction of GHG emissions. Emission reduction grew to 20% if using a 30% green hydrogen blend.

In recognizing these benefits, as of November 2022, more than fifteen American energy and utility companies are actively developing projects to incorporate hydrogen within CCGT facilities (Clean Energy Group, 2022). The Intermountain Power Project (IPP) in Delta, Utah, for example, demonstrates the transition to decarbonize the energy sector. Owners have begun decommissioning its coal-fired power plant to replace it with a less carbon-intensive CCGT unit. To achieve additional emissions abatement, the facility plans to blend up to 30% of its fuel with green hydrogen. Before combustion, the facility will utilize adjacent salt caverns to store hydrogen months before use. Such an arrangement demonstrates the ability for hydrogen to provide elongated energy storage, which current battery technology cannot satisfy (Intermountain Power Agency, 2022).

Section 1.3 The Potential for Green Hydrogen in California

Hydrogen can be produced from solar PV through an electrolyzer. The electrolyzer takes electricity from the solar PV asset and splits a water molecule into its fundamental hydrogen and oxygen atoms. The hydrogen can then be captured, purified, treated, compressed, stored, and transported for its ultimate use-case. Hydrogen can be further defined by the characteristics of the electricity going into the electrolysis process:

- **Green Hydrogen**. If the lifecycle emissions are near zero and the electricity source is carbon-free.

- **Blue Hydrogen**. The electricity source is generated from hydrocarbons, but the lifecycle emissions are mitigated via carbon capture, utilization, and storage (CCUS).
- **Gray Hydrogen**. The electricity source is generated from hydrocarbons, and the lifecycle emissions are not-abated (Choksey, 2019).

While most of the hydrogen produced today is gray, a growing share of final energy demand will be green (Frankowska, Mańkowska, Rabe, Rzeczycki, Szaruga, 2022). Due to its abundance of solar and wind generation, California uniquely stands as a market with immense opportunity for growth in the green hydrogen economy.

This study specifically seeks to analyze the application of retrofitting an existing utility-scale solar PV asset with electrolyzers that produce green hydrogen. Retrofitting distressed utility-scale solar PV assets within California Independent System Operator (CAISO) jurisdiction may provide a landing point for hydrogen developers while also remedying underperforming solar investments. This study will seek to highlight one or several combinations of technological and economic variables that would lend themselves to positive financial returns from electrolyzer retrofits. The study will also conduct stress tests upon the economic inputs to the distressed assets to guide future investment solar PV plus electrolyzer retrofits.

The analysis examines the benefits, costs, risks, and opportunities of pairing solar generation with hydrogen production from the perspective of project developers, investors, and owners. The methods for the analysis include cost-benefit analysis, lifecycle cost analysis, techno-economic analysis, and Monte Carlo simulation. Industry and academic professionals would benefit to understand what combination of techno-economic factors signal potential financial improvement from hydrogen electrolyzer retrofits.

Chapter 2 - Methods for Assessing the Feasibility of Green Hydrogen Retrofits

Section 2.1 Identifying the Duck Curve Problem

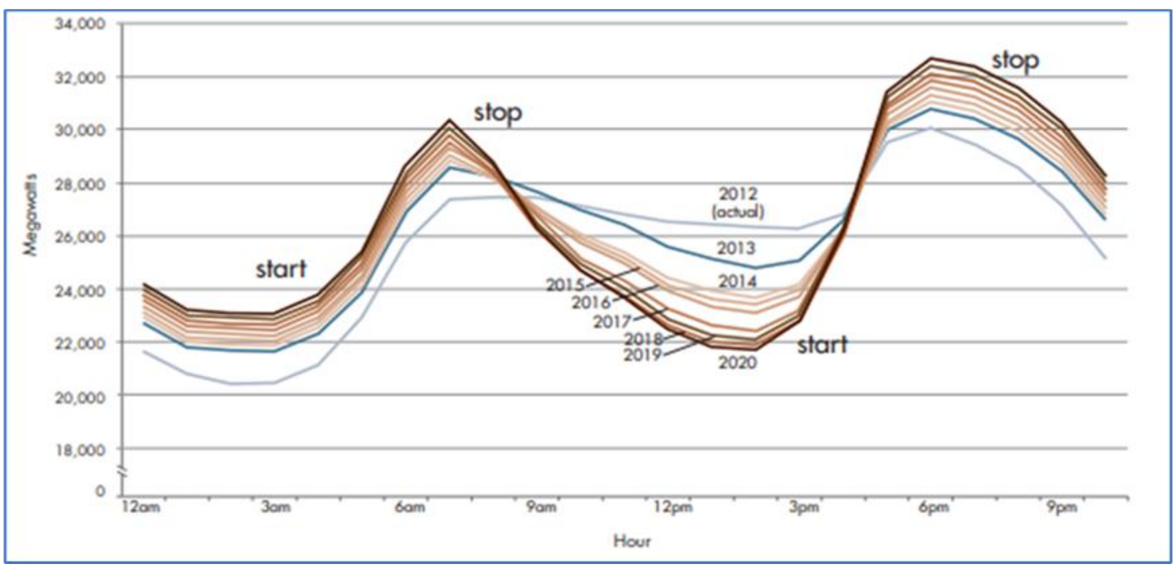
The electricity grid was originally designed, engineered, and constructed to meet variable demand with dispatchable supply. The difficulty with high penetration of renewable energy resources in the supply stack manifests itself with how grid operators now must balance both variable demand and variable supply.

Typical electricity grid operation relies upon substantial planning, analysis, and forecasting. Grid operators aim to satiate electricity demand and do so in a least-cost planning method known as the Production Cost Model (PCM) (Jorgenson & Denholm, 2018). Grid reliability and cost-effectiveness drive these PCMs. The ability to dispatch generator units to achieve optimal power flow allows operators to attenuate the supply of electricity to grid load in the most cost-effective manner. Traditional energy generation units such as coal-fired power plants, CCGTs, and even nuclear generators are dispatchable, meaning that operators can solicit their generation on command. Barring ramp-up times and fuel shortages, these sources of energy can be controlled. On the other hand, wind turbines and solar photovoltaic arrays must conform to ambient components of weather patterns like wind speed/direction and solar irradiance. They produce electricity when natural Earth cycles permit, not necessarily when it is economically advantageous (Lin & Magnago, 2017). This paradigm shift challenges grid infrastructure and reliability.

Figure 2 illustrates that rapid changes in net load require traditional generators to meet shortened, aggressive ramp times, which increases stress on the grid and diminishes asset lifespan. Operators not only risk damaging the grid if surplus electricity is not curtailed, they can also undersupply the grid if dispatchable resources cannot fulfill intermittent supply gaps (CAISO, 2017). Moreover, energy mixes consisting of large proportions of inverter-based assets challenge aspects of grid reliability like frequency response, which ensures electricity quality (Jorgenson & Denholm, 2018). The difference between forecasted load and expected electricity production from variable generation resources is known as Net Load, or The Duck Curve (CAISO, 2016).

Figure 2 – *The Duck Curve*

What the duck curve tells us about managing a green grid

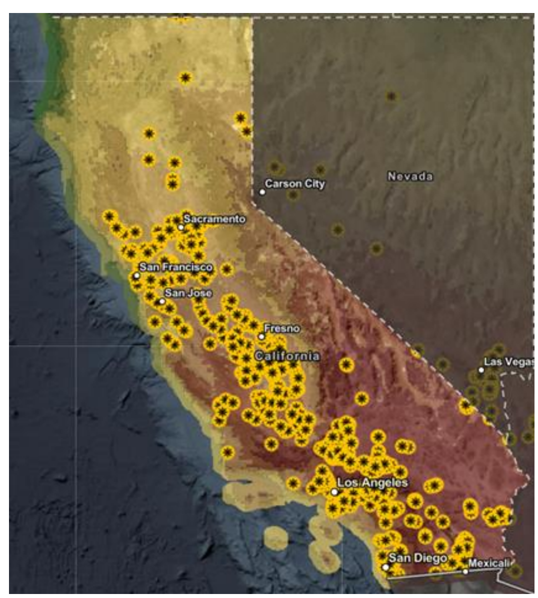


(CAISO, 2016)

Due to physical and economic constraints of the transmission grid, large amounts of electricity need to be intermittently curtailed throughout CAISO and other renewable-intensive energy networks. Economic curtailment provides grid operators with least-cost options for dealing with excess demand. This is the practice of reducing power output of a solar photovoltaic (PV) asset due to economic reasons (e.g. the price of power is negative) when it could have otherwise produced power. Because these curtailments rely on price indicators, they are market-based and therefore more efficient than other forms of curtailment like exceptional dispatch (CAISO, 2017). Abundant supplies of solar-derived electricity crowd the market and plummet the market-clearing price of power. This alters not only instantaneous pricing but also average pricing over extended periods of time. Figure 3 overlays California high voltage transmission network against the global horizontal irradiance index. Yellow dots represent utility-scale solar PV assets. This illustrates that the highest solar irradiance is in Southern California in regions that do not have a robust transmission network to bring the solar power to the load centers.

Figure 3 – California Solar Irradiance and Energy Distribution

Interactive GIS data viewer



(EIA, 2022)

As a result of the Duck Curve and the general mismatch of supply and demand for renewable electricity in California, the market experiences deleterious price signals to market participants. During these events, forms of demand management (i.e., Hydrogen production) could alleviate potential economic and infrastructure stresses related to electricity grid planning within CAISO (California Independent System Operator) while also fulfilling demand for green hydrogen.

Section 2.2 Green Hydrogen

As an alternative to exporting low-value electrons onto the electricity grid, the electrons can be converted into green hydrogen by way of an electrolyzer. In other words, the electricity generated from the solar PV asset can be transmitted to an electrolyzer via distribution lines, transformers, inverters, and rectifiers. The electrolyzer then uses that electricity to split a water molecule into hydrogen and oxygen. The hydrogen is then captured, dried, purified, compressed, and stored for a myriad of use-cases such as methanol, ammonia, oil refining, synthetic fuels, heating, or even electricity production. Hydrogen may also be liquefied and transported, typically via trucks, ships, rail, or pipes, for its ultimate use-case. For this study, green hydrogen is evaluated at the point of production, including production, compression, and storage but not liquefaction, transportation, or dispensing (G. Turk, personal communication on October 23, 2022).

Suppose the source of the electricity comes directly from a clean energy generator (e.g. solar PV asset). In that case, the resultant hydrogen can be codified as green, meaning it is a low-carbon process. Hydrogen may also be codified as turquoise, blue, gray, pink, etc. depending on if the technology uses pyrolysis or steam methane reformation and if the source of the energy comes from fossil fuels or clean energy sources (National Grid, 2022).

Section 2.3 The Promise of Green Hydrogen

Green hydrogen has been viewed under the lens that it may be a solution to the Duck Curve by improving the financial performance of the most impaired assets. When the CAISO wholesale market prices are suppressed, the solar PV asset could produce green hydrogen instead of curtailing energy output or selling energy during low value hours. This gives the asset two pathways for its electricity output and the opportunity to seek out high-value revenue streams to improve the asset's financial performance in the eyes of project appraisers (Christensen, 2020).

Currently, there are three leading commercial electrolyzer technologies: Alkaline, Proton-Exchange Membrane (PEM), and Solid Oxide (SOEC). For this study, only PEM electrolyzers are evaluated due to their ability to pair with the fluctuations and variability of solar PV production in-real time. The solid-state chemistry in a PEM electrolyzer allows its capacity to ramp up and down in a way that is compatible with non-dispatchable resources like solar PV (DOE, 2022).

Section 2.4 Evaluation of the Green Hydrogen Retrofit

To demonstrate the effect of hydrogen electrolyzer retrofits, this case study uses a fixed balance of system (BOS) solar PV array and compares its financial performance against adjustments to input costs. As the results are recorded, a portfolio is built, and the results normalized. By highlighting those combinations of financial inputs that resulted in the best financial performance, the case study will serve as a launch point for solar PV practitioners. The intended purpose of this study is to eliminate the ambiguity and guesswork involved in the decision-making process of a distressed utility-scale solar PV asset.

Section 2.5 Building the Cost Benefit Analysis Framework

The cost benefit analysis framework is an effective tool for evaluating the business case of building new-generation clean energy infrastructure assets. In this framework, the asset's forecasted revenues can be compared against its estimated costs for a myriad of applications. The results of these cost benefit analyses can then be compared between the solar PV only asset and the solar PV asset that is retrofitted with green hydrogen facilities. These results enable the evaluation of the financial viability of the project (Domah and Pollitt, 2001). The cost benefit analysis can be used from the perspective of an investor, developer, or owner of the asset.

Section 2.6 Building the Life Cycle Cost Analysis

In this study, the cost benefit analysis is paired with a life cycle cost analysis to incorporate the time dimension for the benefit and cost streams. The asset's costs and benefits may extend through the useful life of the project. The useful life is defined as the period between the commissioning and decommissioning of the project (NREL, 2022). The useful life for the solar PV asset is determined to be 35 years and the useful life of the green hydrogen asset is determined to be 20 years, with the inclusion of replacement costs on the electrolyzer stacks. The coupling of a cost benefit analysis with a useful life cycle assessment (or a discounted cash flow model) allows for the evaluation of a project's return of investment (ROI).

A project's ROI is the metric by which an asset's financial performance is measured. The ROI is calculated by dividing the project's net profit over the useful life by the cost of the investment. It is often expressed as a percentage and is the rate of return to make the investment's net present value equal to zero (Birken, 2022).

For this application, the ROI is calculated for both the solar PV asset alone and for the solar PV asset that is retrofitted with the green hydrogen facilities. The asset with the larger ROI shows stronger financial performance than its counterpart. The Investment Tax Credit (ITC) is incorporated for the solar PV asset at 30% and the Production Tax Credit (PTC) is incorporated for the green hydrogen facilities at $3 per kilogram of hydrogen. Outside of the inclusion of these federal policies, the ROI is calculated as pre-tax and unlevered to remain agnostic against policies levied by local authorities having jurisdiction (AHJ) and against investment preferences for the financing assumptions.

Section 2.7 Economic viability

To assess the financial performance of an asset, a lifecycle financial model, known as a pro forma, is often constructed. The pro forma amortizes annual revenues and expenditures over the lifespan of the asset. In doing so, the pro forma calculates key metrics such as earnings before interest, taxes, depreciation, and amortization (EBITA) and internal rate of return (IRR). Additionally, the pro forma accounts for itemized price fluctuations over time, which is often the result of discounted cash flows and/or depreciation. By enumerating cash flows proactively, the pro forma allows developers, investors, and policymakers to increase the specificity of their decision making.

Section 2.7.1 EBITA

The pro forma calculates EBITA year-over-year and reflects the asset's operating costs, excluding up-front capital expenditures. The EBITA figure demonstrates how well the asset performs at the margin, which is especially useful when considering assets with a diverse set of expenditure and revenue streams (Hayes, 2022). The pro forma used within this study accounts for revenue streams from the contractual sale of electricity, the wholesale sale of electricity, renewable energy credits (RECs), wholesale hydrogen market, and hydrogen PTC. Similarly, this study accounts for operating costs such as the cost of water, electricity, and general operation and maintenance O&M). Thus, EBITA represents these figures as net cash flows per annum.

Section 2.7.2 IRR

The IRR accounts for both fixed and operating costs and determines overall financial feasibility. While fixed costs do not affect profitability at the margin, they do provide accurate financial forecasting of project to-be. The IRR encompasses a comprehensive suite of financial attributes and can be used to compare one project to another. The formula used to calculate the IRR is described below.

Equation 1: Return on Investment

$$\boldsymbol{NPV} = \sum_{t=0}^{t} \left[\frac{\boldsymbol{C_t}}{(\mathbf{1} + \mathbf{r})^{\mathbf{t}}} \right]$$

NPV = the net present value of the project investment, equal to zero when solving for [r]

C_t = the annual cash flow

r = the internal rate of return

t = the number of years

Section 2.8 Building the Techno-Economic Analysis

This study also includes a techno-economic performance analysis, which is an assessment of the overall value of technology. In this application, the technical performance of the solar PV asset and the green hydrogen asset are included in the evaluation of technological risk and its cascading impacts on the asset's financial performance. For example, the solar PV's production output, the electrolyzer's efficiency, the overall project's degradations, etc. are determined through technological evaluations and the resulting predicted performance of the asset.

National Renewable Energy Laboratory's System Advisor Model (NREL SAM) was utilized to determine the performance of the solar PV asset. The Software is a techno-economic model that takes the solar PV system equipment, orientation, and configuration to determine both the annual production and hourly production of electricity from the solar PV asset. This study used annual weather data from Blythe, California to simulate annual solar irradiance. The BOS included a SunPower SPR-E19-310-COM monocrystalline silica PV array with a 120MW dc nameplate capacity. The array held a 0° tilt with a ground-coverage ratio (GCR) of 0.3. The system utilized a 380V Yaskawa Solectria Solar: SGI 750XTM with a 1.2 DC-AC ratio, therefore the array's ac output was 100MW. Based on these inputs, NREL SAM determined the specific production of the solar array was 2,347 kWh/kWp.

To identify economically distressed assets, the predicted hourly production is critical to determine the solar-weighted locational marginal price (LMP) for the selected CAISO nodes. The predicted annual production is cited to evaluate the project's ROI as the electricity output may be sold to the wholesale market or utilized by the electrolyzer to produce green hydrogen and then sold to an off-taker. In both scenarios, the technical performance of both the solar PV and green hydrogen assets are critical to the financial performance.

Section 2.9 Building the Monte Carlo Simulations

Incorporating risk and uncertainty enhances the project appraisal because the techno-economic benefits and costs over the useful life are not deterministic values but rather subject to variation under different future scenarios. In this application, the variables are stochastic and vary significantly due to uncertainty in future asset performance, energy market dynamics, and policy settings, etc. Furthermore, the risk profile of the solar PV and green hydrogen assets are not equal (e.g., technological risk, financial risk, policy risk, etc.) and the input variables and their corresponding ROI cannot simply be compared in a deterministic way.

A Monte Carlo simulation is a computer-based technique that uses statistical sampling and probability distribution functions to simulate the effects of uncertain variables (GNZ, 2015). Monte Carlo simulations should be paired with a cost benefit analysis because it is meaningful to attach statistical distributions to model the uncertainty. The Monte Carlo simulation is executed for 5,000 multi-dimensional trials and applies a normal distribution (Equation 2: Normal Distribution for Assessing Social Benefits) to each variable.

Equation 2: Normal Distribution for Key Project Assumptions

$$f(x|\mu,\sigma^2) = \frac{1}{\sqrt{2\pi\sigma^2}} e^{-\frac{(x-\mu)^2}{2\sigma^2}}$$

μ= the expected value of the benefit

σ = the standard deviation of the benefit value

x = the simulated outcome of the benefit value

Chapter 3 – Methods for Assessing Distressed Solar PV Assets

Section 3.1 California Electricity Market Fundamentals

CAISO serves as the regional transmission operator (RTO) for most of California and parts of Nevada. CAISO develops policies and procedures to ensure reliable, safe, and economically efficient delivery of electricity. The market consists of two major markets and several submarkets. Both the Day-Ahead Market (DAM) and the Real-Time Market (RTM) account for various factors like infrastructure congestion, weather, and power disruptions. Whereas the DAM is forecasted for the next 24 hours, the RTM serves as a spot market to meet immediate needs. Ancillary submarkets such as frequency response, spinning reserves, and non-spinning reserves further protect grid reliability. These submarkets are incorporated into both the DAM and RTM (FERC, 2022).

The participation in these markets produces a market-clearing locational marginal price (LMP). LMP's vary from node to node throughout CAISO because they incorporate transient factors such as: generation costs, infrastructure constraints, transmission congestion, transmission loss, and other operating characteristics. These variables necessarily change at each location therefore nodal pricing reflects grid attributes at the local level (Lin & Magnago, 2017).

Section 3.2 - Electricity Market Forecasts

Like other RTO's, CAISO conducts annual resource planning for both the short- and long-term. Much of the planning must consider the mismatch between supplied solar PV electricity and peak demand, also known as *net load*. Abundant solar irradiance coupled with sluggish demand for electricity can cause LMP's to plummet and therefore suppress potential revenue streams. In extreme instances, ample supply can result in negative price signals. Such externalities associated with CAISO's electricity market discourage participation as they deflate an asset's ability to generate revenue (Sivaram, 2019).

To avoid the market volatility of the wholesale power markets, renewable energy generators have historically signed power purchase agreements (PPAs). The PPA allows the generator to mitigate market risk by identifying an off-taker with price and delivery clarity. However, both price and contract duration of PPAs are trending downwards and will continue to do so as renewable portfolios expand (Sivaram, 2019). Moreover, existing assets are beginning to roll off their PPAs signed at the beginning of life and are now entering its era of selling merchant power to the wholesale market.

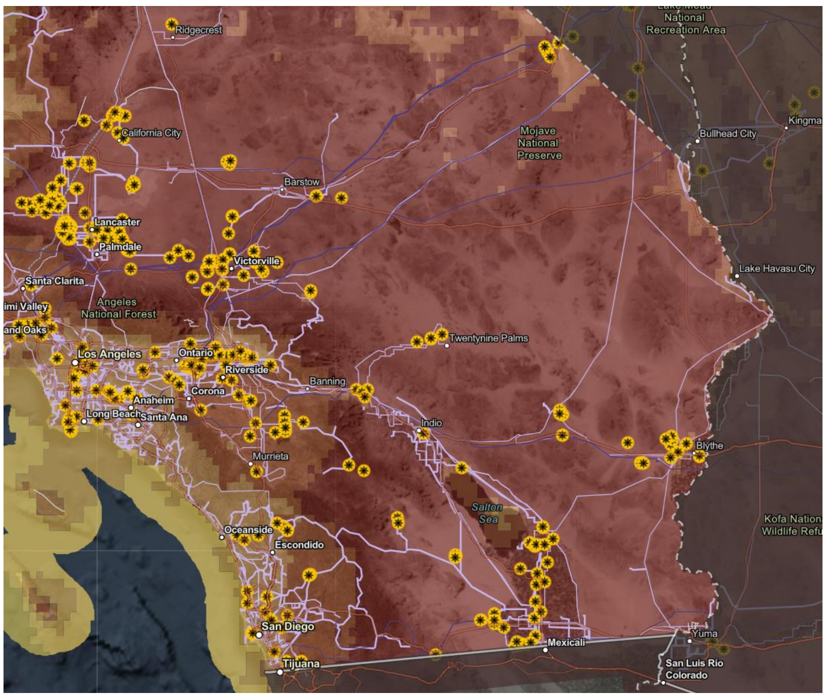
Section 3.3 Solar PV Financial Performance

This study establishes and applies a framework for identifying economically distressed assets that have an increasing likelihood to be strong candidates for experiencing financial benefits from green hydrogen retrofits. A solar PV asset may be experiencing financial hardship for a myriad of reasons, including but not limited to a sub-par revenue contract, lower than expected equipment performance, higher capital or operating costs, and unfavorable market conditions.

Once a project completes its PPA tenor, it may sell power directly into the wholesale market and be compensated at the LMP rate. Because the LMP varies at each node, one project may be compensated at a different rate than another project because it is interconnected to a different node. Furthermore, LMPs and revenue streams from the wholesale market are not guaranteed, thus aging solar PV assets operating outside of a PPA are exposed to financial risk. Due to the innovation of green hydrogen, it is now possible to mitigate price volatility.

Section 3.4 Criteria for Determining Good Candidates for H_2

Figure 4 – *Area of Study: Southern California*
Interactive GIS data viewer



(EIA, 2022)

While a solar PV asset may experience financial hardship for many reasons, this study explains a process for identifying that hardship from the wholesale market perspective. In this study, seven nodes and two hubs were examined. Nodes were selected based on the following criteria:

- Located in Southern California due to the high density of solar PV assets
- Located on the CAISO price map along transmission corridors
- Collectively cover a widespread electrical and topographical area

Table 1 – *Node Locations*

ID	Node	Relative Location	Exact Location
A	BLYTHESC_1_N005	Blythe - along Highway 10	33.615, -114.680
B	C493GEN_7_N003	Ocotillo - along Highway 8	32.739, -115.994
C	DEVERS_1_N103	Sunfair - along Highway 62	34.189, -116.091
D	BAKER_1_N001	Baker - along Highway 15	35.285, -116.060
E	SANGERCO_7_B1	Fresno - along Highway 99	36.707, -119.610
F	CAMINO_2_N001	Fenner - along Highway 40	34.830, -114.990
G	TOT427A_7_N001	Lancaster - along Highway 14	34.704, -118.302
H	SP-15	Southern California	N/A
I	NP-15	Northern California	N/A

Figure 5 – *CAISO Hubs*
OASIS

(California ISO, 2022)

In addition to Nodes A-G on *Table 3*, SP-15 and NP-15 represent regional wholesale electricity market trading hubs in Southern and Northern California, respectively. Using public CAISO datasets, each of these nodes and hubs were then examined at the day ahead market price for the entire year of 2021. The nodes and hubs were then compared on the basis of curtailment, average LMP, and solar-weighted LMP.

- **Curtailment**. Curtailment is identified as the number of hours that the nodal LMP price is negative, hence the solar PV asset is better off to not produce electricity when it could have done so. Nodes that exhibit higher curtailment, in terms of both hours and energy, are more likely to be economically distressed because they are intentionally not producing as much power as they could.

- **Average LMP**. Average LMP is the average for all 8,760 hours of the year.

- **Solar-Weighted LMP.** The solar-weighted LMP is the price relative to the MWh produced by the solar PV asset. It is determined by taking the sum-product of the hourly LMP and the hourly energy yield and then dividing it by the annual energy yield. Nodes that exhibit a lower solar-weighted LMP are less favorable locations to sell power into the wholesale market.

Using NREL SAM, a typical, representative utility-scale solar PV project was modeled under the assumptions listed in the table below. Production data from the simulation was then incorporated into a financial model to determine the representative financial performance of an asset.

Table 2 – *Solar PV Operational Parameters*

Parameter	Assumption
Location	Southern California
Capacity	100 MWac / 120 MWdc
Commercial Operation	December 31, 2010
Power Purchase Agreement Tenor	15 years

The assumptions pertaining to revenue contracts, equipment performance, capital costs, operating costs, and wholesale market prices were then stress-tested in three scenarios: a base case, a favorable case, and an unfavorable case. The favorable and unfavorable cases are representative of the upper and lower bounds, respectively, for a typical solar PV asset of the listed size, location, and commissioning date. Specific assets may experience circumstances outside of the boundaries presented in the assumptions table below.

Table 3 – *Solar PV Financial Parameters*

Parameter	**Unfavorable**	**Base**	**Favorable**
Power Purchase Agreement (PPA) Price	$120 / MWh	$140 / MWh	$160 / MWh
Locational Marginal Price (LMP)	$30 / MWh	$40 / MWh	$50 / MWh
Specific Production	-5%	2,347 kWh/kWp	+5%
Capital Cost	$5.00 / Wp	$4.25 / Wp	$3.50 / Wp
Operating Cost	+10%	$950k / Year	-10%
PV Degradation	0.75%	0.50%	0.25%

Chapter 4 - Methods: Layering on Green Hydrogen

Section 4.1 Solar PV + Green Hydrogen Financial Performance

Like the framework applied for the solar PV financial analysis, an identical framework is applied to solar PV + green hydrogen assets. For these assets, the study examines the condition whereby the solar PV asset is installed and assesses whether or not to retrofit the facility with an electrolyzer to produce green hydrogen. It is assumed that the solar PV has just completed its 15-year PPA of a 35-year useful life; thus, it has 20 years remaining in its asset life with the option to produce hydrogen and/or electricity. The base case for solar PV plus hydrogen assumes PEM electrolyzer installation following a solar-only PPA contract at year 15. This simulates a realistic opportunity for owners to procure revenue streams following PPA expiration. Whereas the solar-only tenor begins in year, 2010, the hydrogen tenor begins in year, 2025.

For this analysis, a typical, representative utility-scale solar PV + green hydrogen project was modeled under the operational parameters table listed in the table below. These assumptions were then inserted into a financial model to determine the representative financial performance of an asset. As follow-up to the stress test and Monte Carlo simulation, adjustments to the sizing and electricity allocation of the electrolyzer relative to the solar PV array were made. The study also examined 1:1 and 2:1 solar PV-to-electrolyzer ratios and 25, 50, 75 and 100% electricity allocation to determine the effects on the internal rate of return (IRR) and solar-weighted locational marginal price (SW LMP).

Table 4 – *Hydrogen Operational Parameters*

Parameter	Assumption
Location	Southern California
Commercial Operation	December 31, 2025
Hydrogen Equipment Useful Life	20 years
Solar PV Equipment Useful Life	35 years

Section 4.2 Revenue Assumptions

The assumptions about revenue streams, equipment performance, capital costs, operating costs, and wholesale market prices were then stress-tested in three scenarios: a base case, a favorable case, and an unfavorable one. The favorable and unfavorable cases are representative of the upper and lower bounds, respectively, for a typical solar PV + green hydrogen asset of the listed size, location, and commissioning date. Specific assets may experience circumstances outside of the boundaries presented in the assumptions table below.

Table 5 – *Hydrogen Financial Parameters*

Parameter	Unfavorable Assumption	Base Assumption	Favorable Assumption
Hydrogen Price	$1.50 / kg	$2.00 / kg	$2.50 / kg

Specific Production	-5%	2347 kWh/kWp	+5%
Capital Cost	$2.00 / Wp	$1.50 / Wp	$1.00 / Wp
Operating Cost	+10%	$2,850k / Year	-10%
Electrolyzer Efficiency	55 kWh / kg	50 kWh / kg	45 kWh / kg
Electrolyzer Degradation	0.75%	0.50%	0.25%
Stack Replacement Interval	7 years	10 years	13 years

Section 4.2.1 Production Tax Credit (PTC)

The PTC is a subsidy furnished by the U.S. federal government through the Inflation Reduction Act of 2022 to qualifying clean hydrogen projects. The bill established a tiered hierarchy of subsidies based on lifecycle emissions. Hydrogen of lower carbon intensity garners greater federal support than that of higher carbon intensity. Tier 1 hydrogen demonstrates a 95% reduction from that produced from steam-methane reformation (SMR), or 0-0.45 CO_2/kgH_2, and qualifies for a \$3.00/kgH_2 production tax credits (PTC). Due to the no-carbon electricity source associated with green hydrogen, each of the solar plus hydrogen cases assume a revenue stream of \$3.00/kg of hydrogen produced through the lifespan of the electrolyzers.

Table 6 – *IRA Hydrogen Subsidies*

Adapted from *How the Inflation Reduction Act can help hydrogen hubs succeed*

Life-Cycle Emissions (kg CO_2e/kg H_2	**Investment Tax Credit (percentage)**	**Production Tax Credit Value (2022 \$/kg H_2)**
4 - 2.5	6%	$0.60
2.5 - 1.5	7.5%	$0.75
1.5 - 0.45	10%	$1.00
0.45 - 0.0	30%	$3.00
kg = kilogram, CO_2e = carbon dioxide equivalent, H_2 = hydrogen		

(Bergman & Krupnick, 2022)

Section 4.2.2 Price of Hydrogen

The study assumes that the price of hydrogen remains fixed at $2.00/kg of hydrogen produced throughout the lifetime of the electrolyzer tenor. This rate is competitive with other hydrogen being brought to market (Morgan Stanley, 2022).

Section 4.3 Cost Sensitivities

Section 4.3.1 Electrolyzer Operation and Maintenance

Operating costs of the electrolyzer in 2025 are assumed to be 1.5 times the operating costs of the solar PV asset in 2010 ($1,425,000), which is derived from Lazard's LCOE analysis (2021). Operating costs are applied each year and escalate 2% year-over-year to account for inflation associated with operations and maintenance costs.

Section 4.3.2 Electrolyzer Stack Replacement

Electrolyzer stacks must be replaced every 7-13 years. A 10-year replacement interval was selected for the base case, 13-year interval for the favorable case and 7-year interval for the unfavorable case. Stack replacements expenditures spell significant implications for the project lifecycle. Replacements typically cost $200,000 per MW, or $20,000,000 for a 100 MW solar array.

Section 4.3.3 Electrolyzer Capital

Capital costs are derived from three parameters: electrolyzer cost, development cost, and balance of system costs. Each parameter is typically measured in dollars per watt peak ($/Wp).

The sum product of these parameters totals $150,000,000 and serves as a fixed cost applied in the first year of operation only.

Section 4.3.4 Electrolyzer Efficiency Degradation

Electrolyzer efficiency is assumed to be 50 kWh/kg H_2 in the base case, 55 kWh/kg H_2 in the unfavorable case and 45 kWh/kg H_2 in the favorable case. Because electrolyzer efficiency degrades over time, the rate of degradation was also included within this study. Electrolyzer performance degraded by 0.25% per year and 0.75% per year in the favorable and unfavorable cases, respectively. The base case assumes 0.5% degradation per year.

Ch. 5 - Results

Section 5.1 CAISO Market Characteristics

Table 7 – *2021 CAISO Market Characteristics at Node and Hub Level*

ID	Node	Curtailed Electricity (MWh)	LMP ($/MWh)	Solar-Weighted LMP ($/MWh)	LMP Disparity
A	BLYTHESC_1_N005	10,018	47.24	$32.56	(-) 14.68
B	C493GEN_7_N003	4,992	49.08	$35.52	(-) 13.56
C	DEVERS_1_N103	13,663	48.35	$33.15	(-) 15.19
D	BAKER_1_N001	1,204	50.49	$37.04	(-) 13.44
E	SANGERCO_7_B1	1,827	53.22	$39.85	(-) 13.37
F	CAMINO_2_N001	4,898	47.68	$34.21	(-) 13.47
G	TOT427A_7_N001	4,119	50.43	$37.13	(-) 13.30
H	SP-15	5,209	49.94	$38.63	(-) 11.31
I	NP-15	1,296	52.36	$43.89	(-) 8.47

Every selected node within the study experienced curtailment in 2021. Curtailment also occurred in both Northern and Southern California hubs, albeit more prevalent in SP-15. The SP-15 hub curtailed electricity more frequently than NP-15, which resulted in four times the amount of foregone electricity. Because electricity hubs retain thousands of nodes within their jurisdiction, their data may be regarded as average – indicative of the collection of nodes. Nodes, A and C curtailed approximately double the electricity than their SP-15 hub. Node C exhibited the highest number of curtailed hours, curtailed energy (MWh), and lowest solar-weighted LMP.

Differences between the average annual LMP and SW LMP occurred throughout the sample nodes and hubs. The smallest distinction occurred at hub, NP-15, whereas the largest difference occurred at node, C. LMP disparity varied by \$6.21/MWh for an average difference of \$12.98/MWh.

Table 8 - *Summarized 12x24 Chart for Node, C*

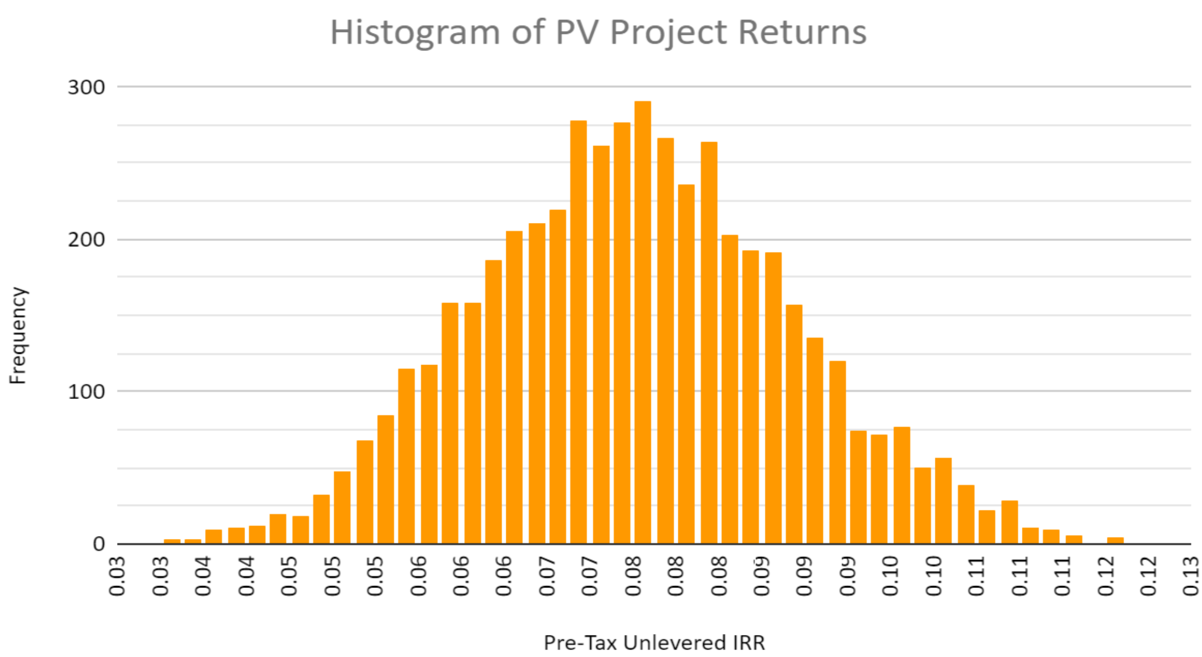
	Hour												
Month	7	8	9	10	11	12	13	14	15	16	17	18	19
1	0	0	274	1235	1290	1241	1373	1168	1090	0	0	0	0
2	0	0	165	685	955	1046	1083	1260	857	244	0	0	0
3	0	166	1423	2310	2278	2121	2064	2106	2224	2004	1035	0	0
4	0	0	100	200	400	400	389	398	200	180	88	0	0
5	0	0	0	400	499	499	399	400	300	97	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0

Table 8 summarizes annual curtailment on a monthly and hourly basis. Hours 1-6 and 20-24 are excluded because it is unnecessary to curtail at night when solar PV assets are not supplying electricity to the grid; thus, those values are zero and unnecessary. On average, node C curtailed most frequently in springtime afternoons, and the majority of which occurred in the month of March. Because this chart broadly demonstrates when electricity is foregone, the highlighted areas suggest times when hydrogen production could potentially occur.

Table 9 – *Results from Solar Only Stress Test*

SOLAR Sensitivities	Low	Med	High
PPA Rate ($/MWh)	120.00	140.00	160.00
Pre-tax, unlevered IRR	**5.948%**	**7.546%**	**9.200%**
Specific Production (kWh/kWp)	-5%	2,347	+5%
Pre-tax, unlevered IRR	**6.877%**	**7.546%**	**8.20%**
PV Capital Cost ($/Wp)	5.00	4.25	3.5
Pre-tax, unlevered IRR	**5.651%**	**7.546%**	**10.15%**
PV Operating Cost ($000s/yr)	+10%	950	-10%
Pre-tax, unlevered IRR	**7.496%**	**7.546%**	**7.59%**
LMP ($/MWh)	30	40	50
Pre-tax, unlevered IRR	**7.147%**	**7.546%**	**7.90%**
PV Degradation (%/year)	0.75	0.5	0.25
Pre-tax, unlevered IRR	**7.217%**	**7.546%**	**7.86%**

Figure 6 – *Histogram of PV Project Returns*



Section 5.2 Solar Only Economic Sensitivities

Curtailment data, alone, is an insufficient means to gauge asset performance. Table 8 summarizes the findings for each scenario of the solar only economic stress tests. The base case for the representative solar only asset held an IRR of approximately 7.546%. The PPA rate and capital costs were the biggest drivers of the economic performance of the asset. Specific production is the next biggest driver of economics. Finally, LMP resulted in non-negligible economic effects.

The Monte Carlo simulation expanded these individual findings into a normalized bell-curve by representing a probabilistic distribution of IRR outcomes. IRR is likely to reside between 6% and 9%, as this appears to be within one to two standard deviations. The maximum and minimum expected IRRs were approximately 12% and 3%, respectively.

Section 5.3 Solar Plus Hydrogen Economic Sensitivities

Table 10 – *Results from Solar Plus Hydrogen Stress Test*

HYDROGEN Sensitivities	Low	Med	High
Hydrogen Revenue ($/kg)	1.50	2.00	2.50
Pre-tax, unlevered IRR	**5.686%**	**6.074%**	**6.425%**
Specific Production (kWh/kWp)	-5%	2,347	+5%
Pre-tax, unlevered IRR	**5.272%**	**6.074%**	**6.852%**
H2 Capital Cost ($/W)	2.00	1.50	1.00
Pre-tax, unlevered IRR	**5.366%**	**6.074%**	**6.727%**
H2 Operating Cost ($000s/yr)	+10%	2,850	-10%
Pre-tax, unlevered IRR	**6.019%**	**6.074%**	**6.129%**
Electrolyzer Efficiency (kWh/kg)	55	50	45
Pre-tax, unlevered IRR	**5.724%**	**6.074%**	**6.461%**
Electrolyzer Degradation (%/year)	1.5	1.0	0.50
Pre-tax, unlevered IRR	**5.995%**	**6.074%**	**6.155%**
Stack Replacement Interval (Yrs)	7	10	13
Pre-tax, unlevered IRR	**5.979%**	**6.074%**	**6.078%**
PTC Duration (Yrs)	35-45	25-35	25-45
Pre-tax, unlevered IRR	**4.502%**	**5.169%**	**6.074%**

Similar stress tests were conducted for the PV plus hydrogen asset. The base case produced an IRR of 6.074%. Specific production and hydrogen capital cost were the biggest drivers of financial performance. The timing of the PTC tenor also played a substantial role in determining IRR.

Section 5.4 Hydrogen Allocation and Sizing Ratio

Table 11 – *Hydrogen Allocation and Sizing Ratio Matrix*

Electrolyzer Allocation	PV:H2 Ratio 2:1		PV:H2 Ratio - 1:1	
	SW LMP ($/MWh)	IRR (%)	SW LMP ($/MWh)	IRR (%)
100% H_2 Allocation	$60.63	7.18%	$-	6.07%
75% H_2 Allocation	$53.97	7.03%	$68.99	6.02%
50% H_2 Allocation	$47.69	6.81%	$55.72	5.79%
25% H_2 Allocation	$41.08	6.46%	$45.36	5.26%

IRR values diminished as less electricity was allocated towards hydrogen production. Whether equally sized, or offset by a factor of two, 100% allocation resulted in the highest IRR values. The 2:1 ratio experienced better financial performance than did the 1:1 ratio. That is, an electrolyzer with half the capacity as the solar PV array elicited better financial performance. In this 2:1 scenario, allocating just 25% of electricity towards hydrogen electrolyzers resulted in a higher IRR than 100% allocation in a 1:1 ratio.

Ch. 6 – Discussion

Section 6.1 CAISO Market Characteristics

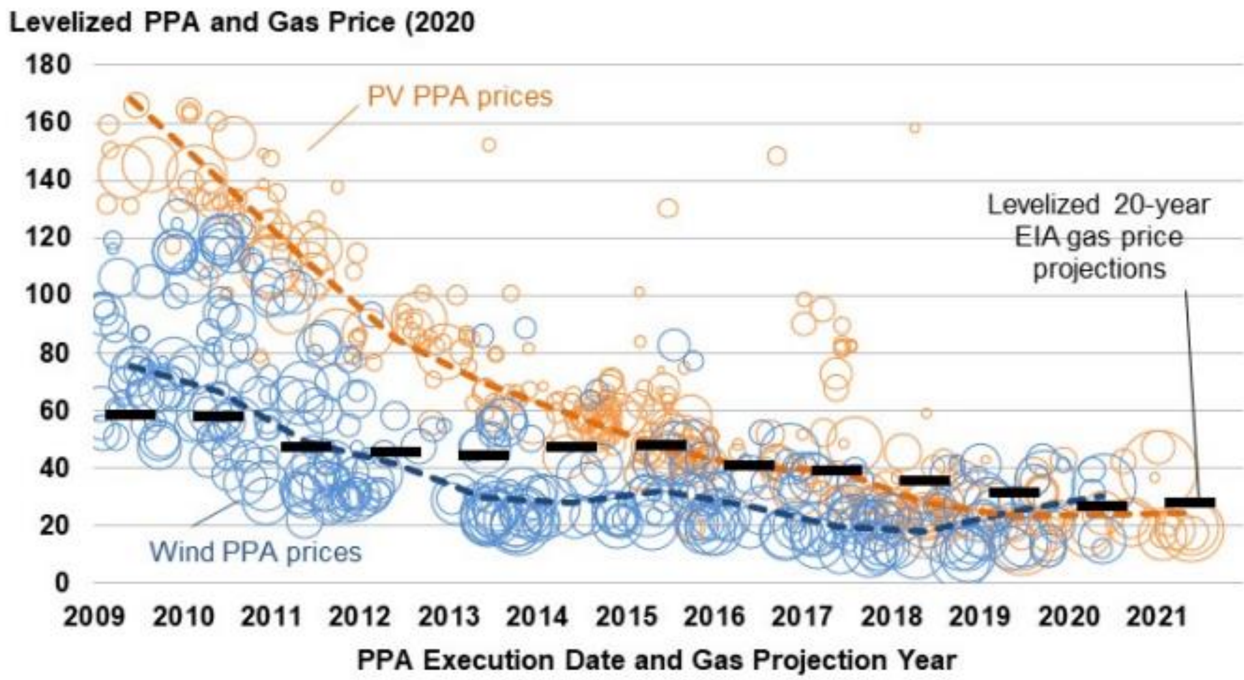
The level of curtailment occurring at both the hub and nodal levels suggests that electricity supplied is – at times – outpacing demand. The disparity in curtailed hours between SP-15 and NP-15 confirms that oversupply to the electricity grid is more prevalent in Southern California than in Northern California, occurring about three times as often. Solar-weighted LMP was negatively correlated with curtailment. Node C curtailed the most energy (MWh) and exhibited the lowest solar-weighted LMP. On the other hand, NP-15, which experienced the least amount of curtailment, also witnessed the highest SW LMP. These characteristics align with symptoms of transmission congestion related to issues stemming from oversupply. The findings ostensibly demonstrate *net load* and other economic disparities associated with the Duck Curve.

Section 6.2 Economic Sensitivities: Solar Only

The PPA rate and capital costs were the biggest drivers of the economic performance on the asset; however, these parameters are typically known by the time of project financing. Because PPA prices directly affect the revenue streams, higher PPA rates bolster asset performance. The rates used in this study reflect 2010 prices when the hypothetical project was created. These rates have greatly reduced. In 2021, PPA contact prices for utility-scale solar PV projects within the CAISO averaged just $20/MWh—a reduction of approximately 85% (Feldman & Margolis, 2021). Thus, given modern PPA rates, a solar only arrangement would not be as successful as demonstrated in this study and may stand to benefit from electrolyzer retrofits.

Figure 7 - *Levelized PPA*

Fall 2021 Solar Industry Update



(Feldman & Margolis, 2021)

Section 6.3 Economic Sensitivities: Solar + H2

PTC implementation, capital costs, and specific production were the biggest indices of financial performance. The results of the PTC parameter suggest that the timing of electrolyzer retrofits and their revenue streams affect operation. Because asset performance and its ability to generate cashflows degrades over time, retrofitting a solar array with electrolyzers earlier in its tenor will help to recoup its capital costs. This aspect of the study suggests that owners who retrofit their assets quickly will see better results.

The Solar + H2 base case hampered financial performance by reducing the IRR from 7.546% to 6.074%. Depending on macroeconomic conditions, this IRR may not be sufficient. Investors may want to improve the expected IRR before allocating capital. According to Mendelsohn & Feldman (2013), financially viable projects are those where the weighted average cost of capital (WACC) is less than the IRR. For utility-scale solar PV projects, IRR values should be between 7-10%. Well-known strategies to improve traditional financial performance include downsizing the ratio of electrolyzer to PV capacity and optimizing revenue streams by curtailing electricity based on LMP parameters (Mendelsohn & Feldman, 2013).

Section 6.4 Electrolyzer Sizing and Allocation

The sizing and allocation results demonstrate that it is more ideal to downsize the capacity of the hydrogen facility relative to the capacity of the solar PV facility. Scenarios with higher hydrogen allocation performed better financially than scenarios with lower hydrogen allocation. This is because under sizing the electrolyzer relative to the solar PV array bolsters the capacity factor of the retrofits. As more electricity is allocated to the electrolyzer, the utilization of that equipment increases, which allows it to recoup its initial capital cost investment. A secondary benefit is that the remaining electricity that is not allocated to the hydrogen electrolyzer can be sold to the wholesale power market at high value hours, evidenced by the increasing solar-weighted LMPs.

When considering the optimal equipment size and electricity allocation a project developer, investor, or owner should compare the financial metrics for each scenario. In addition, the volume of hydrogen and electricity output should be evaluated on the requirements of any transactions that may exist between the asset and an off-taker.

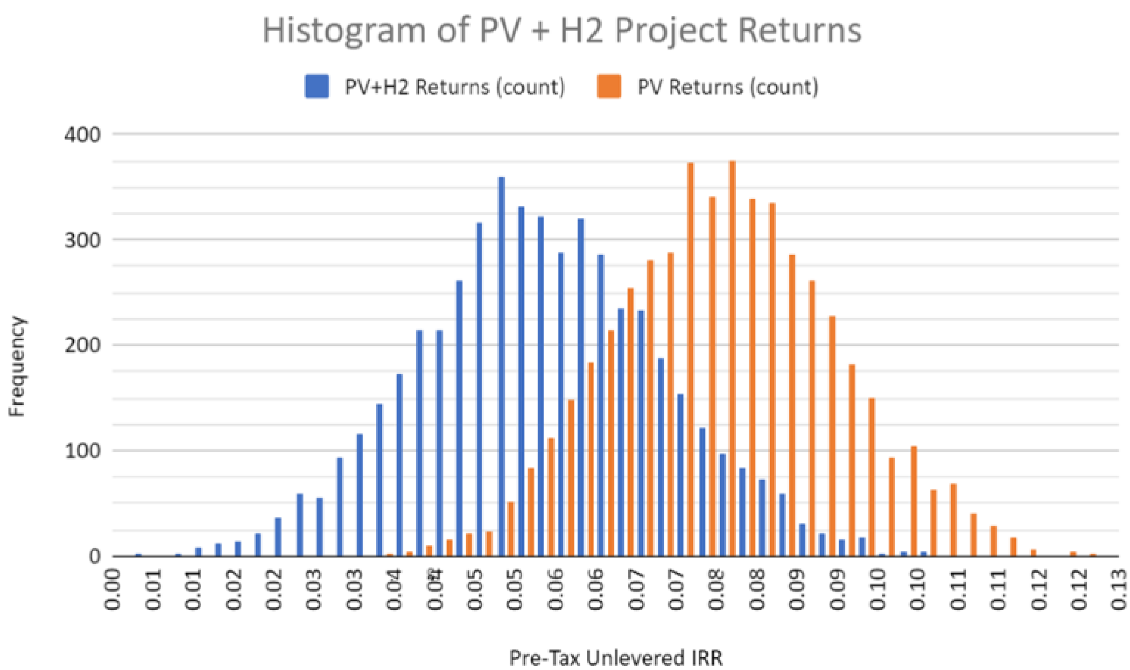
Section 6.5 Policy Implications

The impact of national policy on hydrogen procurement and use cannot be overstated. The Bipartisan Infrastructure Law of 2021 incentivizes the development of hydrogen infrastructure and electrolysis manufacturing. Grants and subsidies encourage the development of "hydrogen hubs", or centers of agglomeration aimed at mass-producing hydrogen (IEA, 2022). Imperative nomenclature defines Clean Hydrogen as that which is, "produced with a carbon intensity equal to or less than 2 kg CO2/kgH2 produced on-site and 4 kg CO2/kgH2 in lifecycle emissions" (Morgan Stanley, 2022, p. 77).

In terms of project finance, both the solar and hydrogen projects greatly benefit from direct subsidies. The investment tax credit (ITC) and renewable energy credit (REC) both support solar production, while the PTC subsidizes hydrogen production. This study illustrates the importance of these financial mechanisms in boosting IRR values and overall asset performance. Were it not for these subsidies, the range of possible outcomes may skew probability distributions to the left, towards lower IRR values.

Section 6.6 Solar + H_2 Probabilistic Success

Figure 8 – *Histogram of PV and H_2 Project Returns*



While the solar + PV base case produced a lower IRR than the solar only case, project uncertainty and inherent risk can elicit many unforeseen outcomes, which the Monte Carlo simulation exemplifies. There are situations in which hydrogen retrofits within these specific assumptions improve IRR, indicated by the overlapping normal distributions in Figure 8. Such situations are defined by exceptionally low PPA-rate, low cost of capital for both solar and hydrogen assets, high LMPs associated with the project's corresponding trading node, and high price of hydrogen.

Although the financial performance of the PV only base case suffered due to the volatility of LMP prices, high-rate PPA revenue streams earlier in its lifespan corrected these drawbacks. As demonstrated by this study, were it not for these guaranteed PPA revenue streams, the solar + hydrogen case might have outperformed the solar only case.

Finally, the results suggest that assets would benefit from policies that encourage economies of scale, reduce transportation costs, and improve electrolyzer efficiency. Retrofitting assets with electrolyzers as early as possible, avoiding low PPA rates during solar-only timeframes, reducing the cost of capital, and under sizing the electrolyzer should maximize financial performance.

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