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Economic Case for Replacing High-Emitting Peaker Plants with Fuel Cells for Automotive Applications

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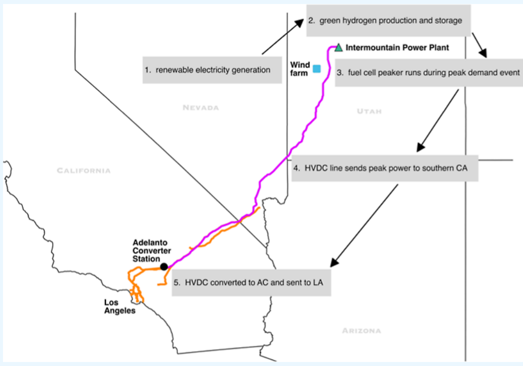
ABSTRACT: The identification of clean and cost-effective solutions to replace high-emitting peaker plants and support a just transition is a challenge faced by utilities across the US today. However, falling costs of hydrogen production as well as the widespread availability of fuel cells for automotive applications have made them an attractive option for a zero-emission peak power supply. This study evaluates the techno-economics, operation, and environmental justice impacts of siting a peaker plant based on fuel cells for automotive applications through the lens of the existing Intermountain Power Plant, in order to supply peak power to the Los Angeles basin. Compared to the fossil fuel-fired peakers in operation today, the fuel cell peaker would be lower-cost up to a 17% capacity factor with Inflation Reduction Act incentives while also reducing air pollution in environmental justice communities. With corresponding transmission upgrades, the Intermountain site could host up to a 5 GW fuel cell peaker in the future.



■ INTRODUCTION

Fossil fuel-fired peakers, power plants that sit idle most of the year except when dispatched to supply periods of high electricity demand, have traditionally played a key role in ensuring resource adequacy. However, these plants tend to be aged and inefficient, with above-average pollutant emissions per unit of generated electricity, and are disproportionately located in disadvantaged urban communities.[1−3] With equity a top priority in many jurisdiction's decarbonization plans, a number of projects across the US have focused on swapping high-emitting peakers with battery energy storage to unlock environmental, health, and economic benefits.[2−8] Although today's commercially available battery storage systems—which are largely based on lithium-ion technology—are well-suited for short duration applications (<10 h) like daily peak shaving, they are less-suited for long-duration applications (10−100 h) like multiday peak demand events due to their limited capacity and lifespan.[9,10] Further, previous work has questioned the economic viability of sizing battery storage systems to fully replace the service provided by existing fossil fuel-fired peakers, especially to meet the top fifth percentile of load events.[11] Against the backdrop of a growing need for peak power, as the power system is increasingly based on clean but variable renewables, the search for cost-effective clean peakers based on commercially available technologies continues.

Whereas historically the use of hydrogen in power generation has been regarded as cost-prohibitive,[9,10,12] recent developments have converged to present a new opportunity for its utilization. First, generous tax incentives from the Inflation Reduction Act (IRA) have substantially improved the economics of green hydrogen production.[13] This hydrogen can be leveraged in a stationary system of fuel cells for automotive applications, which have become widely commercially available as well as affordable: fuel cells for automotive applications cost only about 10−20% of fuel cells for stationary applications as a result of mass manufacturing, lower durability ratings, and a historical industry focus on combined heat and power rather than power-only applications.[14−19] Further, the fuel cells for stationary applications—which are typically considered for power generation—require high durability ratings to serve as baseload generation, translating to high assumed cost,[9] while fuel cells designed for automotive applications used to serve infrequent peak power demand events do not require similarly high durability ratings. Alternatives, namely, hydrogen combustion turbines, are not currently commercially available at scale—not least without blending with natural gas—and although they do not emit carbon, they do emit NOx—a precursor to ground-level ozone and PM2.5 formation.[20] While previous work has assessed the economic viability and technical feasibility of siting fuel cells designed for automotive applications in a stationary application for power generation,[21−27] questions remain about a fuel cell

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peaker's role in an increasingly clean and equitable energy system. Here, these questions are explored through the lens of the Los Angeles (LA) basin by evaluating the costs, dispatch and operation, and environmental justice benefits of replacing today's peak power generation from natural gas with a fuel cell peaker at the site of the Intermountain Power Plant (IPP).

■ METHODS

Peaker System Costs. The analysis focuses on the LA basin given its poor air quality, high incidence of urban fossil fuel-fired peakers, goal of 100% carbon-free energy by 2035, as well as its electrical connectivity to Delta, Utah, via a high voltage direct current (HVDC) transmission line.[28−30] Delta is home to the soon-to-be-retired coal-fired IPP as well as the largest salt dome in the Western United States (US), which is being developed for geologic hydrogen storage.[31−33] In order to leverage this interconnection and storage facility and avoid hydrogen transportation barriers, it is assumed that hydrogen production is located near the IPP site. The renewable potential within a 100-mile radius of the IPP is surveyed, and a site ∼45 miles SSW with strong wind conditions is identified (i.e., a capacity factor of ∼38%). Matching this capacity factor to NREL's Annual Technology Baseline (ATB), an estimate for the levelized cost of electricity (LCOE) at this location can be obtained;[34−37] 7 USD/MWh—factoring in the cost of a spur line to connect the wind farm to the IPP site. The electrolyzer capacity to wind capacity ratio is optimized in order to minimize the levelized cost of hydrogen, finding that a 1:1.05 ratio is optimal; this indicates that the wind farm is slightly oversized to support an electrolyzer load factor of 40%. The cost of hydrogen production includes the price of wind electricity used for production as well as the levelized cost of the electrolyzer investment (including the compressor), which comes out to 3.79 USD/kg H2.[22,35] A mature and commercial technology, hydrogen storage in salt caverns is generally regarded as the lowest-cost option—especially for applications like peak power generation, which are infrequent, yet may require large volumes when used—with costs expected to continue declining in the next 10−15 years; thus a levelized cost of storage in salt caverns of 0.22 USD/kg H2 is assumed based on monthly cycling.[36] The total unsubsidized cost of hydrogen fuel is, therefore, 4.01 USD/kg H2.

Capital costs of the fuel cell peakers are taken to be the sum of the stack and stack balance of plant (BOP),[14−16] plus the remaining costs including the electrical balance of system (BOS), the inverter, installation, and overhead and grid interconnection that are estimated from NREL's ATB for utility-scale storage of a 4 h duration at a 240 MW h scale.[37] Heavy duty vehicle (HDV) fuel cells based on proton-exchange membrane (PEM) technology with a power capacity of 275 kW are selected, given their lower cost and higher durability over light duty vehicle fuel cells when manufactured at scale.[14−16]

Provided certain wage and apprenticeship requirements are met, the fuel cell peaker system could claim several incentives from the IRA: the renewable energy production tax credit (PTC) of 27.5 USD/MW h for 10 years for the wind farm's generation, the hydrogen PTC of 3 USD/kg H2 for 10 years for the electrolyzer's production, and the investment tax credit (ITC) of 40% for the fuel cell system investment (increased by 10 percentage points from the standard 30% due to the energy community distinction, given the coal-fired power plant)—all levelized over a lifetime of 30 years starting with a model year of 2023.[13,38] With IRA incentives, the total subsidized cost of hydrogen fuel comes out to 11.89 USD/MMBtu (USD1.60/kg of H2). Meanwhile, a natural gas price of 3.42 USD/MMBtu is assumed, reflecting the EIA-reported daily Henry Hub spot price average from 2013 to 2022.[39] The capital cost of a HDV peaker with salt cavern storage comes to 390 USD/kW with the IRA ITC. Cost assumptions are summarized in Table 1; full cost assumptions can be found in Tables S1 and S2 in the Supporting Information.

Table 1. Key Cost Assumptions for the Peaker System

variable	unit	value	note
system lifetime	years	30	
discount rate	%	6	
wind LCOE	USD/MW h	37.7	class 7 moderate land-based wind, 2023[34]
electricity cost—subsidized	USD/kg H2	1.29	with IRA incentives
capital cost—electrolyzer	USD/kW	1441	includes stack, BOP, and EPC for PEM in 2023[35]
capital cost—compressor	USD/kW	47	22
electrolyzer load factor	%	40%	optimized
levelized storage cost—salt cavern	USD/kg H2	0.22	assumes monthly cycling[36]
total cost of H2 fuel—unsubsidized	USD/kg H2	4.01	with IRA incentives
total cost of H2 fuel—subsidized	USD/kg H2	1.60	
natural gas price	USD/MMBtu	3.42	daily Henry Hub spot price average, 2013−2022[39]
capital cost—HDV FC	USD/kW	235	275 kW PEM, stack and BOP, 100,000 units/yr[14]
electrical BOS	USD/kW	176	utility-scale storage in 2021, 4 h duration[37]
total FC system cost—unsubsidized	USD/kW	650	with IRA incentives
total FC system cost—subsidized	USD/kW	390	

Fuel Cell Peaker Dispatch and Operation. To simulate the operation of an fuel cell peaker, hourly technology-level generation data from NREL's LA100 study are used.[9] Because the LA basin is a summer peaking region, the 2045 (summer) peak demand week with the baseline SB100 scenario and moderate demand is analyzed. Since the majority of seasonal peakers are simple cycle gas turbines (SCGTs), their generation is replaced with a fuel cell peaker. To estimate the cost of reconductoring the Southern Transmission System (STS) and associated HVAC lines that bring power from the IPP to the LA basin, line length, voltage level, and number of circuit information is first obtained from refs 30 and 40 and cost estimates are derived based on methodology from ref 41.

Existing Peaker Emissions Analysis. To analyze the emissions of existing peakers in the LA basin, the utilization and operating profile of individual peaking units are first examined. A data set of all plants that are in current operation and primarily burn natural gas,[42] in the LA basin within LA county, is obtained and plants that serve as cogeneration or are run privately by refineries, medical centers, or universities are excluded, to focus on conventional gas-fired power generation. For the resulting 15 plants, since natural gas turbines often run below maximum capacity, the hourly unit-level generation data

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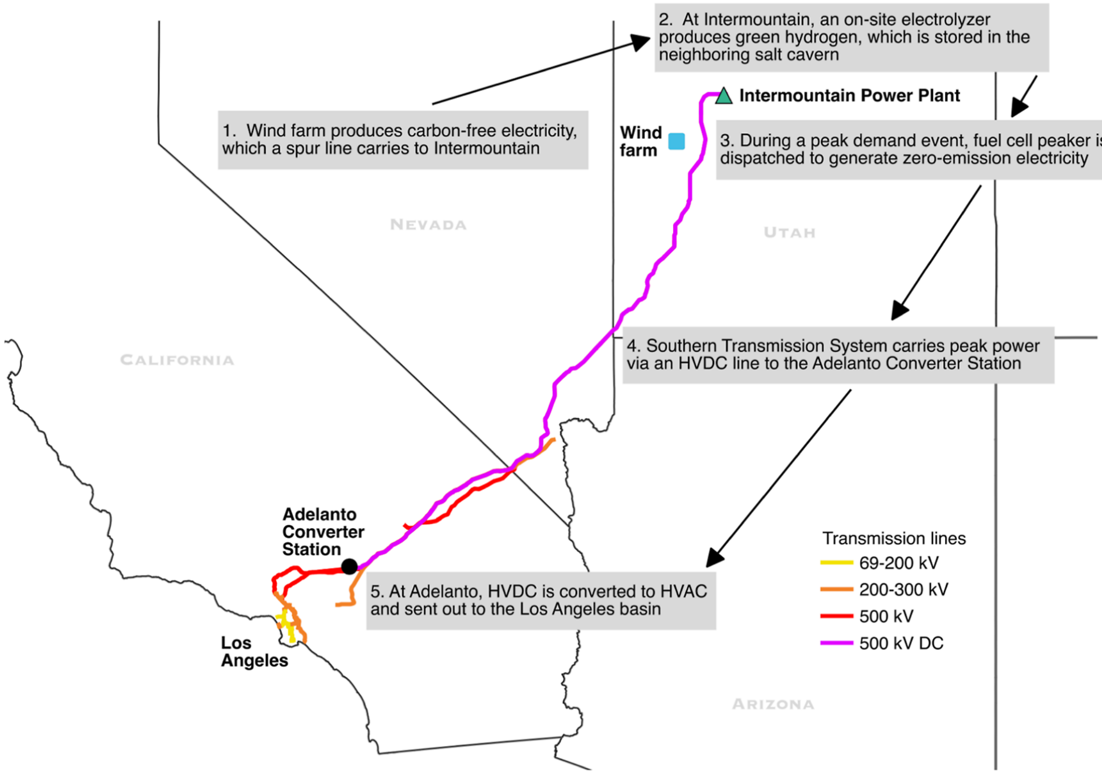

Figure 1. Schematic of the proposed fuel cell peaker. Transmission lines reflect those owned and operated by LADWP by voltage level. HVDC is high voltage direct current; HVAC is high voltage alternating current.

are used to obtain the total generating hours and average number of starts in 2021, the most recent year with complete data. From this, an average duration per start and an annual utilization rate is calculated. Based on these two metrics, each existing gas-fired unit in the LA basin is categorized as a seasonal peaker (average duration per start between 5 and 125 h and a utilization rate <10%), daily peaker (average duration per start <5 h, no limit on the utilization rate), or nonpeaker (all other plants). Once categorized, standard winter and summer generation profiles for the gas units in the LA basin are examined: seasonal peakers operate mostly in the summer, where they typically operate continuously for a few days to meet the higher demands of hot summer days, while daily peakers generally serve daily evening peaks and nonpeakers serve a baseload to intermediate load function throughout the year. To then analyze emissions from peaker plants, hourly unit-level NOx emission data are obtained and the average emissions per MW h in 2021, the most recent year with complete data, are calculated.[42] A summary of the results can be viewed in Table S3 in the Supporting Information.

To geospatially relate plant emissions to socioeconomic status, detailed data from the California Air Resources Board[43,44] on California priority populations are leveraged. These populations are made up of disadvantaged communities (as designated by California Senate Bill SB-535, communities identified by the California Environmental Protection Agency based on geographic, socioeconomic, public health, or environmental hazard criteria)[45] and low-income communities (per California Assembly Bill AB-1550, census tracts that are either at or below 80% of the statewide median income and/or below the Department of Housing and Community Development's designated threshold).[46] The latter bill additionally designates communities within a 1/2 mile of disadvantaged communities as well.

RESULTS AND DISCUSSION

Peaker Techno-Economics. A schematic of the proposed fuel cell peaker at the IPP site is shown in Figure 1. Powered by abundant local wind, an electrolyzer would produce green hydrogen on-site and store it in a large salt cavern. During a peak demand event, the fuel cells for automotive applications would draw hydrogen from the salt cavern to generate electricity, which would then be transmitted via the HVDC STS to the LA basin. At present, the STS is a 2400 MW, ±500 kV, 488-mile transmission line that primarily carries power generated at the 1900 MW coal-fired IPP—which primarily powers the LA basin, with the LA Department of Water and Power (LADWP) entitled to the largest share, albeit with some local Utah municipalities and cooperatives as well.[30−32,47] Notwithstanding the "IPP Renewed" project's plans to retire the coal plant in 2025, construct 840 MW of turbines burning a mixture of gas and hydrogen[31] and the several GW of local renewable energy projects that currently await in the interconnection queue,[32] there remains significant spare capacity on the STS for a FC peaker to complement existing plans while serving renewable droughts.

The annualized costs of a fuel cell peaker at the IPP site are next calculated, with stacked IRA incentives playing a key role in bringing down both the capital costs and operating expenses (hydrogen fuel) of the peaker system (Figure 2a). Compared to a conventional peaker—a natural gas-fired combustion turbine—a fuel cell peaker proves more economical up to approximately a 17% capacity factor, within the normal utilization of a typical seasonal peaker. In contrast, a combustion turbine capable of running partly or entirely on

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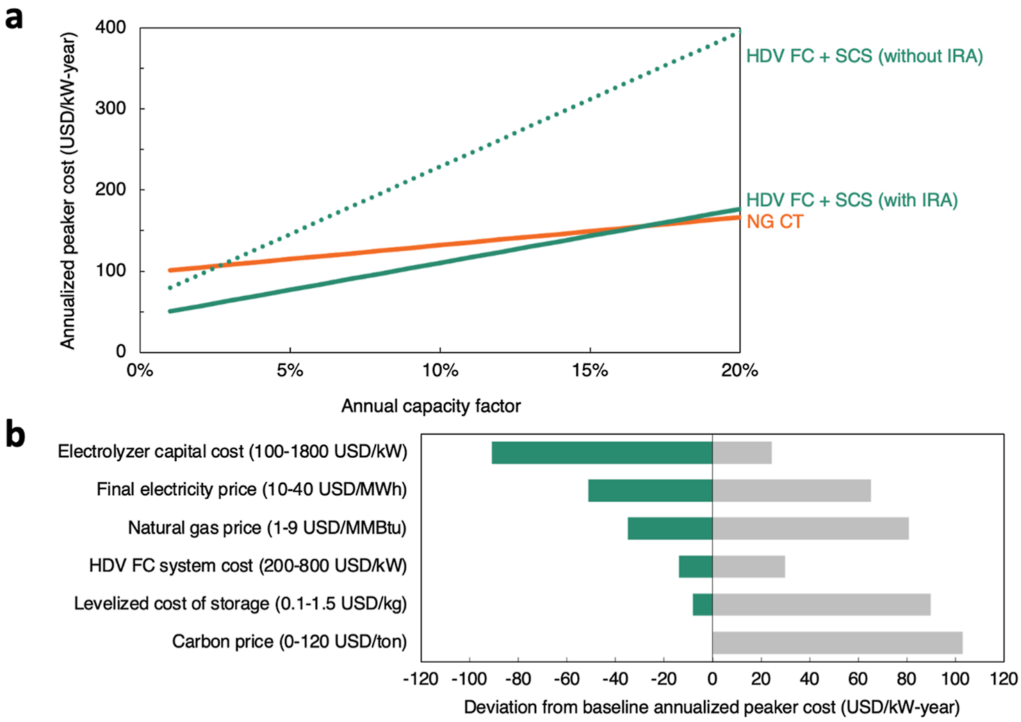

Figure 2. Annualized costs of an FC peaker at the IPP site compared to a conventional gas turbine. (a) Annualized costs as a function of annual capacity factor. (b) Sensitivity analysis for an FC and NG CT peaker system. Baseline annualized peaker cost is 157 USD/kW-year, the point at which an FC peaker breaks even with a NG CT peaker. Baseline assumptions include a 1441 USD/kW electrolyzer capital cost, 23 USD/MW h final electricity price, 3.42 USD/MMBtu natural gas price, 390 USD/kW HDV FC system cost, 0.22 USD/kg H2 levelized cost of storage, and zero carbon price. For each input, values are calculated as the deviations from the baseline peaker cost while keeping the baseline assumptions constant for all other inputs. Gray bars depict an increase in annualized peaker cost while green bars depict a decrease in annualized peaker costs, relative to baseline assumptions. The natural gas price and carbon price bar refers to the annualized cost of the NG CT, while the other values refer to the annualized cost of the FC peaker. HDV FC is heavy duty vehicle fuel cell; NG CT is natural gas combustion turbine; SCS is salt cavern storage; IRA is Inflation Reduction Act.

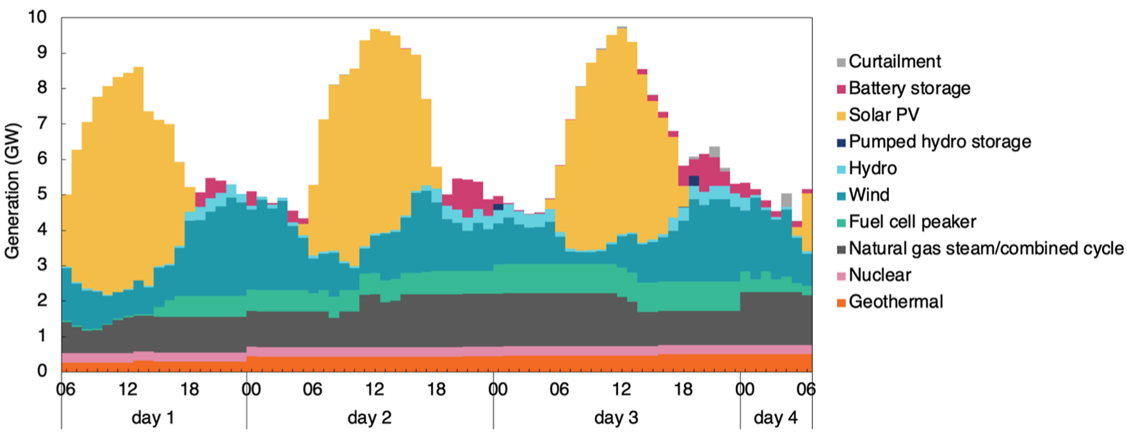

Figure 3. Dispatch of a fuel cell peaker in LADWP in 2045. It corresponds to the 2045 (summer) peak demand week with the baseline SB100 scenario and moderate demand. Different colors correspond to different sources of generation.

hydrogen would likely be significantly more expensive than a standard gas-fired combustion turbine of today. Further, while the support of the IRA incentives may decline depending on the starting year of operation, the subsequently analyzed sensitivities to key input variables show that the magnitude of the electrolyzer capital cost has the largest impact on the annualized cost of the fuel cell peaker (Figure 2b); however, costs of electrolyzers are predicted to fall significantly from 1441 USD/kW in 2023 to around 542 USD/kW in 2030 for the stack, BOP and engineering procurement and construction (EPC), counteracting lower IRA incentives.[35]

Dispatch and Operation. Figure 3 shows the LA basin's forecast hourly generation dispatch for a multiday peak demand event in the summer of 2045.[9] From a grid perspective, a fuel cell peaker would operate similarly to a natural gas peaker: it would ramp up at the start of the multiday peak demand event, at a rate equivalent to or faster than the ~25 MW/min or 10%/min of rated capacity of gas turbines today[48] and then operate continuously for several days

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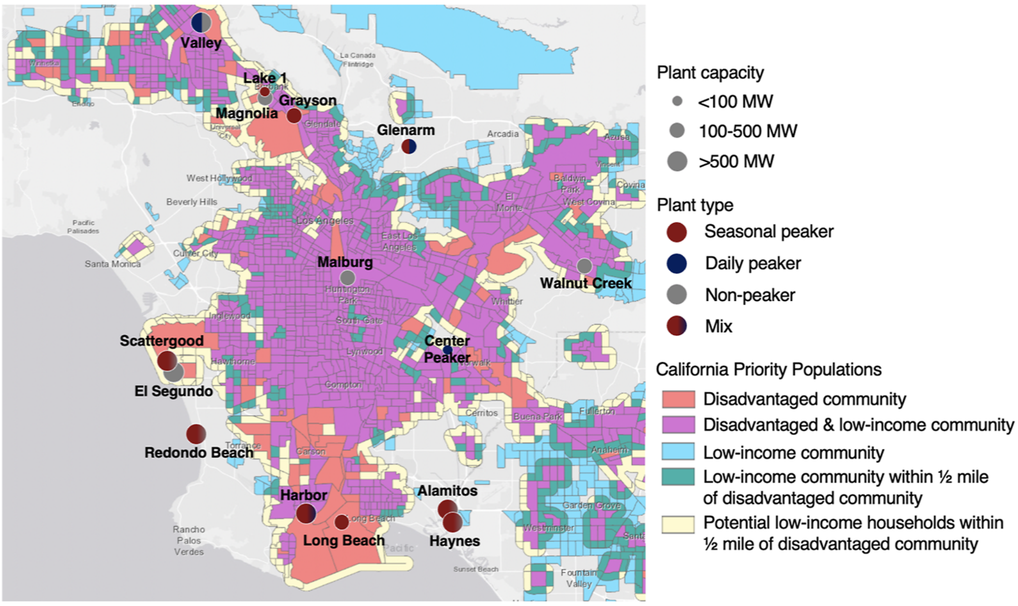

Figure 4. Map of natural gas-fired plants and California Priority Populations in the LA basin. Since some individual plants may be composed of colocated units with different utilization profiles (i.e., peaking, baseload, etc.), all plant types are shown by the colors in each circle in the figure. The size of the circle corresponds to the total plant capacity. The color of the census tract designates different California Priority Populations.

and ramp down when demand subsides and/or other lower-cost generation sources increase supply. During this multiday peak demand event, the fuel cell peaker provides a maximum contribution of 1 GW to LADWP's power mix, a capacity which could be accommodated on the existing 2400 MW STS without the need for additional transmission upgrades. Although the fuel cell peaker's contribution is contingent on sufficient hydrogen being available from storage, a 1 GW peaker with up to 100 h of duration would require ∼150 GW h of hydrogen storage, accounting for fuel cell efficiency, which represents the approximate capacity of one of two caverns that are in construction at the Utah salt dome.[33]

Shifting the peak power capacity out of the basin may raise concerns about grid reliability and system adequacy. To this regard, battery storage is well-suited to address in-basin stability issues and assist in early evening peak-shaving needs (Figure 3) as they can be geospatially distributed at the locations of former fossil-fuel fired plants, in line with the repowering plans of many existing plants in the LA basin.[28,49] For seasonal peak power, investigation of siting a fuel cell peaker with location-agnostic pressurized container storage over hydrogen combustion turbines is warranted. Future work should investigate the implications of FC peakers on reliability standards. In the near term, i.e., before 2035, existing fossil fuel-based capacity can be retained as a back-up for times of low renewable energy generation, transmission outages, and other contingencies, while under normal operation, cost-effective emission-free peak power could be sourced from the IPP site to help accelerate the phase-out of fossil-fuel based generation. Such an approach features several benefits: avoiding locking-in multiple years of emissions from new fossil-based firm capacity, lowering the relative value of new fossil power plants compared to renewables, and reducing the effective emissions of existing fossil fuel-based facilities despite the fact that they are not fully shut down.

With LADWP's peak demand set to rise from 6 GW to 8–10 GW by 2045,[9,28] several GW of seasonal peaker capacity is likely to be required, which motivates the exploration of transmission upgrade options to transport additional zero-emission peak power from the IPP site into the LA basin. Forecast dispatch of a peak demand event in 2045 assumes up to 2 GW of wind generation at a given moment, although this supply cannot be guaranteed during renewable droughts, along with up to 1.5 GW of natural gas combined cycle generation at any given moment (Figure 3). An alternative to this variable and/or dirty generation would be to site additional peaker capacity at the IPP, considering that the Utah salt dome is capable of hosting many more salt caverns.[33] However, this would necessitate increasing the transmission capacity of the STS as well as at least the two 500 and 287 kV lines that bring the power into the Rinaldi, Toluca, and Century Receiving Stations in the LA basin after it is converted to AC at the Adelanto converter station.[40] Reconductoring—replacing the existing conductor with an advanced, composite-based conductor—can up to double a line's power transfer capacity within existing right-of-way by expanding the range of thermal operation, while abiding by line sag restrictions.[41,50] While further work is required to assess the feasibility of reconductoring the STS and associates lines and its implications on the wider power system, the cost of reconductoring the HVDC line and three HVAC lines is estimated at 1 billion USD plus upgrades to converter stations in Delta and Adelanto. This upgrade would enable up to a 5 GW fuel cell peaker to be sited at the IPP as well as additional renewable power from Utah and Wyoming to be brought into the LA basin, likely at a fraction of the cost and permitting time of the new transmission.

Supporting a Just Transition. To evaluate the social and environmental health impacts of shifting peak power from natural gas to a fuel cell peaker at the IPP site, each operational natural gas-fired unit in the LA basin is categorized: there is approximately 3.5 GW of seasonal peaker capacity, 1 GW of daily peaker capacity, and 3.8 GW of nonpeaker capacity. In Figure 4, the location, capacity, and categorization of these gas-fired units on a plant level is plotted against a map of low-income and/or disadvantaged communities, referred to as

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California Priority Populations as identified through CalEnviroScreen.[42−46] Seasonal peakers, and natural gas-fired plants in general, are predominantly located in low-income and/or disadvantaged communities. Further, while most nonpeakers are combined cycle gas turbines, seasonal and daily peakers are more commonly SCGTs, which are lower-cost yet release more emissions.

Equity for environmental justice communities, with an emphasis on emissions and pollution reduction, is a stated priority in LA's decarbonization plans.[28] Prior work has shown that across the state of California, peakers tend to operate disproportionately on high ozone days.[2] The emissions of gas-fired units in the LA basin are next analyzed, finding that on annual average, seasonal peakers had 2 times the NOx emissions per MW h of generated electricity of nonpeakers, while daily peakers had 4 times the NOx emissions per MW h of generated electricity of nonpeakers, providing an imperative for the near-term replacement of these seasonal and daily peakers with cleaner alternatives. However, LADWP's current plans to meet 100% clean electricity by 2035 envisage either the offsetting of gas combustion emissions via renewable electricity credits (RECs) or replacing gas-fired plants with hydrogen combustion turbines, which do not actually eliminate NOx emissions and may increase NOx emissions without proper control systems in place.[9,28] Although power plants are likely to represent only a relatively small fraction of NOx emissions in a decarbonized LA in 2045—compared to NOx emissions from the port, buildings, transportation, and industry[9]—the avoided generation and emissions of in-basin gas-fired peakers through the sourcing of seasonal zero-emission peak power from the IPP site would support equitable decarbonization in several low-income and/or disadvantaged communities across the LA basin.

DISCUSSION

The identification of cost-effective and zero-emission solutions to replace high-emitting peaker plants and support a just transition is a challenge faced by utilities across the US, and the world, today. However, the improving economics of hydrogen production along with widespread commercial availability of fuel cells for automotive applications have made them an attractive option for a zero-emission peak power supply. Here, it is shown how up to a multi-GW peaker can be sited and operated to serve the LA basin, demonstrating that it proves cleaner and more cost-effective than the conventional natural gas-fired turbines which currently serve LA's peak power demand.

With LADWP being the largest municipal utility in the US as well as the largest owner and operator of natural gas-fired power plants in the LA basin,[28,44,51] LA's technology and policy decisions are poised to serve as a model for equitable decarbonization for urban areas across the US and the world. In fact, the environmental and human health benefits of phasing out fossil fuel-fired peakers in other locations, which may still burn oil or other petroleum products for peak power, may be even greater than in LA, which predominantly burns natural gas. Yet, despite the potential of fuel cell peakers, in the absence of action, utilities will likely have to turn to more polluting and/or more expensive alternatives to adhere to decarbonization timelines. For example, LA's current policy supports gas plant phase-out yet allows natural gas generation between 2035 and 2045 to be offset with RECs; further, the fuel cell peaker proposed here and corresponding transmission infrastructure upgrades to support up to a 5 GW peaker at the IPP site would likely be a fraction of the estimated 8.4−12 billion USD for developing renewable firm capacity and/or peaking assets for LA by 2045.[9,28] Alternative zero-carbon dispatchable technologies—namely, hydrogen combustion turbines—carry capital costs that may be up to an order of magnitude higher than peakers based on fuel cells for automotive applications.[9] Existing fossil fuel-fired power plants considering replacement or repowering with hydrogen combustion turbines, which would necessitate on-site hydrogen storage, should thus evaluate fuel cells as a lower-capex option. Yet, identifying the most attractive near-term fuel cell peaker deployment opportunities should account for the locations of the highest-emitting and/or most expensive peaker plants in current operation along with factors such as high-quality renewable resources, proximity to existing power infrastructure, and/or low-cost geologic hydrogen storage in the form of salt caverns, such as the Texas Gulf Coast or the European North Sea.[23]

Further work should be conducted to analyze the feasibility and procurement of a fuel cell peaker in LA and other potential locations. For one, there are likely opportunities for synergy with planned repowerings at the IPP (not investigated here) and other existing power plants, including the development of hydrogen storage. Water availability is not expressly evaluated here, although the projected water usage for electrolysis and salt dome development (2500 and 7000 acre-feet of water, respectively) as part of Utah's hydrogen hub development is projected to be well below the current demand of the IPP coal-fired generating units (12,500 acre-feet).[52] As systems grow in size and require the stacking of increasing quantities of fuel cells, the technical configuration of the system will likely have an increasingly prominent impact on system performance, most notably for ramp rates meriting further study to verify the cost assumptions.[53] Further, realization of fuel cell peakers' potential to grow to a multi-GW scale would necessitate the careful evaluation and associated scaling of supply chains. Lastly, it should be noted that the increasing commercialization of cost-effective long-duration storage alternatives, such as iron-air batteries, may affect the present-day cost competitiveness of peakers based on fuel cells for automotive applications.

ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acsomega.4c04227.

Cost assumptions for peaker techno-economics and sensitivity analysis (PDF)

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Notes

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