Scattergood Modernization Project Alternatives: Summary of Findings

National Renewable Energy Laboratory

Produced under direction of the Los Angeles Department of Water and Power by the National Renewable Energy Laboratory (NREL) under Work for Others Agreement number 47833.

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
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Strategic Partnership Project Report
NREL/TP-8A00-93026
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List of Acronyms

AC	alternating current
AEO	Annual Energy Outlook
ATB	Annual Technology Baseline
BESS	battery energy storage system
BTU	British thermal unit
CAISO	California Independent System Operator
CC	combined cycle
CCGT	combined-cycle gas turbine
CT	combustion turbine
DC	direct current
DR	demand response
EIA	U.S. Energy Information Administration
EV	electric vehicle
FCR	fixed charge rate
GW	gigawatt
GWh	gigawatt-hour
HVDC	high-voltage direct current
ISO	independent system operator
kW	kilowatt
kWh	kilowatt-hour
LADWP	Los Angeles Department of Water & Power
LCOE	levelized cost of energy
Li-ion	lithium-ion
LNG	liquified natural gas
MCFC	molten carbonate fuel cell
MMBTU	million British thermal units
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Corporation
NPC	net present cost
NREL	National Renewable Energy Laboratory
O&M	operations and maintenance
OEM	original equipment manufacturer
OTC	once-through cooling
PAFC	phosphoric acid fuel cell
PCM	production cost model
PDCI	Pacific DC Intertie
PEM	proton exchange membrane
PM	particulate matter
PPA	power purchase agreement
PV	photovoltaics
RFP	request for proposal
RPS	renewable portfolio standard
RTO	regional transmission organization

SB100	Senate Bill 100
SLTRP	Strategic Long-Term Resource Plan
SMP	Scattergood Modernization Project (used for this report only)
SOFC	solid oxide fuel cell
STS	Southwest Transmission System
T&D	transmission and distribution
TOU	time of use
TWh	terawatt-hour

Preface

This report was prepared by NREL for use by LADWP. The report has not received the external peer review that is required for all NREL published works.

NREL completed this analysis under the specifications established by the Los Angeles City Council motion 23-0039 and the subsequent Statement of Work agreed to by NREL and LADWP, as well as with technical input provided by LADWP subject matter experts.

Executive Summary

The Los Angeles Department of Water & Power (LADWP) operates the Scattergood Generation Station, which consists of multiple individual generators of various types, sizes, and ages. Included in this set of generators are two older units (Units 1 and 2), with a combined generation capacity of about 284 megawatts (MW) net. These units were completed in the late 1950s, are ocean-water cooled, and required to be shut down by December 31, 2029.

To replace this retiring capacity, LADWP has proposed the "Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project" which we refer to in this document as the Scattergood Modernization Project (SMP). The SMP consists of a new combined-cycle gas turbine power plant rated at about 330 MW and capable of burning a mix of natural gas and hydrogen. The Los Angeles City Council has requested a study to compare SMP to non-combustion alternatives including fuel cells, energy storage, demand response, and new transmission.

This study acts in part as an extension and update of the original Los Angeles 100% Renewable Energy Study (LA100), which identified the need to replace the retiring capacity at Scattergood, and found, in most cases, renewably fueled combustion turbines (similar in nature to the proposed SMP) were the most cost-effective technology to provide this dispatchable capacity. This supplemental study considers changes in technologies that have occurred since the completion of the LA100 analysis in late 2020. It reevaluates the need for dispatchable capacity at the Scattergood location and compares four technology options considering their constructability by 2029, contribution toward reliability, cost, ability to be sited at or near the Scattergood location, and other factors including safety and emissions. The scope of the study is limited solely to a comparison of SMP to non-combustion alternatives.

Based on this updated analysis, this report identifies six key findings on alternatives.

Finding #1: New dispatchable capacity is needed to replace the retiring once-through cooling units at Scattergood.

As in the LA100 study (and other studies), this study finds if the capabilities provided by the once-through cooling (OTC) units are not replaced, LADWP faces a significantly increased risk of unserved energy (outages) if certain transmission assets fail during periods of high demand. The highest risk of an outage is to customers in the proximity of Scattergood, including Los Angeles International Airport.

The capacity added to replace the OTC units must have specific characteristics; for example, it must be able to reliably address potential shortfalls of electricity for multiple hours (generally at least 10) in a row, for multiple days in a row—especially during late summer afternoons and into the evenings. As a result, simply adding variable generation resources, such as wind or solar, cannot meet the reliability requirements.

This additional resource must also be in basin (or out of basin but with an accompanying deployment of transmission delivering this energy in basin). Furthermore, most of this resource must be sited at or very close to the existing Scattergood site. This means many options—including less weather dependent low-carbon resources, such as geothermal—cannot provide an alternative unless accompanied by new transmission on new pathways (see Finding #2) that deliver this electricity into the LADWP grid near Scattergood.

Finding #2: New or upgraded transmission does not appear to be a viable alternative by the 2030 requirement.

The LA100 study included the additional transmission upgrades then planned to be completed by 2030 and did not find further transmission additions to be a viable alternative to replace the retiring OTC capacity at Scattergood by 2030. Avoiding the need for in-basin capacity will likely require *new* transmission on new pathways that can reduce vulnerability to wildfires and deliver energy into the LADWP system near Scattergood. New transmission typically requires more than 5 years to deploy, meaning it cannot be available by the end of 2029 and therefore is not considered a viable alternative to an in-basin resource.

Finding #3: Energy storage durations required to achieve the same level of reliability are at least 10 hours, resulting in a footprint that exceeds the land available at the Scattergood site.

The original LA100 study found battery storage technologies that could be sited at Scattergood were an uneconomic alternative compared to renewably fueled combustion turbines for replacing all the services provided by the existing Scattergood OTC unit. This finding was based on the long durations required to provide reliable service when transmission outages greatly reduce the availability of generation from solar and other renewable resources. This updated study found duration requirements for energy storage are likely at least 10 hours and could be higher if LADWP cannot complete all the solar and other renewable energy projects associated with its high renewable cases proposed in its 2022 Strategic Long-Term Resource Plan (SLTRP). At 10-hour duration, the land area required for a battery of equivalent capacity to SMP (330 MW) greatly exceeds the area available at the Scattergood site. Under the requirement the entire energy storage plant be sited at the Scattergood location, battery storage is not considered a viable alternative.

Additional considerations associated with the storage alternative include limited duration of operational hours before they need to recharge, and ensuring sufficient transmission and generation capacity are available to recharge the batteries. Our analysis indicates that during periods of extreme peak demand, batteries will need to be recharged largely from in-basin (natural gas) generation during overnight time periods. An additional issue that was beyond the technical scope of this study is the potential for reduced life of certain electrical equipment resulting from overnight charging, especially during heat waves. Typically, reduced overnight loads allow transformers and other equipment to cool, and additional loading from storage charging would reduce cooling opportunities, potentially increasing failure rates and requiring accelerated equipment replacement and associated costs, Finally, Appendix B.3 provides additional information on battery storage safety considerations that would need to be considered.

Finding #4: Fuel cells using 100% green hydrogen are unlikely to be a viable alternative to SMP by 2030. Fuel cells using hydrogen/natural gas blends may be a technically viable alternative but at a significantly higher cost premium and will face increased technical and operational risk/uncertainty.

The original LA100 study considered fuel cells uneconomic compared to renewably fueled combustion turbines in all cases, especially before 2035. Since LA100, fuel cells have seen additional albeit limited deployment, and costs remain high.

The city council motion language calls for the consideration of fuel cells that “solely utilize hydrogen that is produced using new, dedicated renewable energy resources or excess renewable energy resources.” The extensive quantity of fuel and related infrastructure required for fuel cells to operate solely on **100% green hydrogen** at the Scattergood location is highly unlikely to be available before 2030. Therefore, the fuel cell alternative that strictly conforms to the city council’s request is likely infeasible.

Alternatively, because SMP begins operation on a blend of hydrogen and natural gas, we also considered the option of fuel cells operating on this fuel mix. We identified two technologies that could potentially provide the same quality of service as SMP: the solid oxide fuel cell (SOFC) and the proton exchange membrane (PEM) fuel cell.

The SOFC is the more mature of the two technologies for stationary applications and can operate on hydrogen/natural gas blends. Costs are highly uncertain, but its total costs of installation and operation are projected to be more than twice those of SMP over a 30-year evaluation period, meaning an ***additional*** cost that would likely exceed $1 billion (net present value) over SMP.

The PEM option is less mature for stationary applications. Its primary benefit is the potential for reduced costs compared to SOFC. Based on National Renewable Energy Laboratory (NREL) estimates, PEM would likely have a cost premium over SMP of at least $600 million—but with a large uncertainty that could result in a cost premium that exceeds $1 billion. PEM cannot run directly on natural gas and requires a reformer to convert natural gas to hydrogen. This reduces the efficiency of the unit and results in some local NOx emissions.

Both fuel cell options result in a small ***increase*** (generally less than 1%) in systemwide CO_2 emissions in 2030 compared to SMP. This is due to the much lower efficiency of the PEM unit and limited flexibility of the SOFC that result in increased use of lower-efficiency gas units. There is negligible change in in-basin NOx emissions from the use of a fuel cell as an alternative.

In addition to the significant cost premium, fuel cell technologies face additional challenges for large-scale deployment before 2030. The largest existing SOFC installation in the United States is 16.6 MW and the largest PEM installation is approximately 1.5 MW, raising concerns about supply chain constraints, manufacturing scalability, and the feasibility of constructing a first of a kind facility of this scale in the time frame required. Other key challenges include operator training requirements, limited operational and maintenance experience at this capacity, and the need for comprehensive safety protocols. In addition, fuel cell technologies require long startup times, specific hydrogen purity levels, and infrastructure modifications to support fuel transitions. Based on these factors, this study aligns with the LA100 conclusion that fuel cells are unlikely to serve as a viable replacement for SMP within the required time frame.

Finding #5: Demand response, as a stand-alone alternative, does not appear to be available in sufficient quantity in the area near the Scattergood site.

Demand response (DR) as a sole alternative to SMP would need to operate for periods of 10 hours or more, and it would potentially be called on multiple days in a row. Although this study was not able to evaluate the required geographic distribution of DR resources, LA100 findings suggest much of the capability would have to be located in proximity to Scattergood. Under the assumption demand response in itself must match all these requirements, this study was unable to identify a sufficient amount of economic DR and methods to orchestrate it to match these requirements and consequently provide the same level of reliability as the SMP. Demand response alone was therefore not considered a viable option to replace SMP.

Consistent with LA100 and LADWP goals, this study does find individual sectors and end uses in the LADWP service territory could contribute significant capacity toward a balanced and economic solution. Achieving full potential would require an orchestration of DR resources with a level of coordination LADWP has not yet demonstrated but is anticipating in its request for proposal (RFP) to automate, consolidate program data, and introduce new offerings for DR. This approach depends on achieving high participation and response rates through well-designed programs and incentive structures as well as automation and visibility through advanced metering infrastructure and DR management systems not yet established within LADWP. In addition, it introduces uncertainties around design, development and implementation timelines and achievable outcomes. Such solutions were not simulated in detail.

Finally, it should be noted that the 2022 SLTRP (now called LA100 Plan), which includes SMP, already includes about 350 MW of demand response. This means to replace SMP, LADWP would need to obtain an *additional* 330 MW of DR, or a total of about 680 MW. Furthermore, this additional 330 MW of DR would be required for a sufficient duration and equivalent level of reliable response.

Finding #6: Combination options can reduce the cost premium of the alternatives but are still likely more expensive and do not eliminate significant technology risks

NREL identified several combination options that would cost less than an alternative consisting of a single option. These options include a combination of fuel cells and storage or a combination of fuel cells and DR. Although these can reduce the cost premium associated with the fuel cells, these combinations are still substantially more expensive than SMP, and do not eliminate technology risks associated with large-scale fuel cell deployments.

Overall, the findings of this study support the conclusions of LA100, which find it is difficult to identify economically viable and deployable alternatives to new combustion resources at the Scattergood location given the challenges of transmission constraints in the LADWP grid near Scattergood, the need to maintain reliable operation during extended outages, and the need to deploy an alternative by the end of 2029.

It is important to note the findings of this report are *specific to replacement of the retiring OTC units* and not general findings about the state of individual technologies, many of which are expected to make significant contributions toward LADWP's clean energy goals and reliability requirements. For example, although new and upgraded transmission likely cannot serve as an alternative to SMP, new and upgraded transmission can still provide significant economic benefits to the system as a whole by giving LADWP access to lower-cost renewable resources throughout the Western United States. Likewise, LADWP is developing both energy storage and demand response as part of LADWP's larger portfolio. As a result, this report does not replace LADWP's more extensive planning process, which considers the larger portfolio.

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1 Introduction and Background

The Los Angeles Department of Water & Power (LADWP) operates Scattergood Units 1 and 2, which are ocean-water cooled (once-through cooling [OTC]) power plants with a total net output of about 261 megawatts (MW).[1] This pair of units is abbreviated as the Scattergood "OTC" units in this document. These OTC units are required to be shut down by December 31, 2029.

To replace this retiring capacity, LADWP has proposed the "Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project," abbreviated here as "SMP."[2] This project consists of a combined-cycle power plant capable of burning natural gas or a mix of natural gas and hydrogen. The proposed plant has a capacity of "up to 346 MW" (gross), or about 330 MW net.[3]

In response to the proposed project, the Los Angeles City Council directed LADWP to

> "conduct a new or updated assessment of non-combustion alternatives to the project, including the use of green-hydrogen powered fuel cells, high levels of energy storage, large-scale multi-day demand response programs, new and upgraded transmission lines to import higher levels of renewable energy, and others that considers the public health benefits, safety risks, and costs and benefits."[4]

Subsequently, LADWP entered a task order agreement with the National Renewable Energy Laboratory (NREL) with the following description:

> "The National Renewable Energy Laboratory (NREL) shall provide technical and professional services related to the evaluation of alternatives to the Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project, in direct response to directives of the Los Angeles City Council (Council File No. 23 0039)."

1.1 Analysis Approach in the Context of LA100

The LA100 study identified possible pathways for LADWP to achieve 100% clean electricity in various time frames and with various technology options.[5] LADWP relies on imports from out-of-basin resources for much of its generation, and its extensive transmission network allows the import of relatively low-cost resources including hydropower, nuclear, wind, and solar. At the same time, LADWP relies on in-basin gas generators to provide reliable capacity and safeguard against transmission and other failures.

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[1] 2022 SLTRP Table E-1.

[2] https://www.ladwp.com/community/construction-projects/west-la/scattergood-generating-station-units-1-and-2-green-hydrogen-ready-modernization-project.

[3] Gross capacity is the generation before consideration of the power consumed by the plant to operate. Net capacity is capacity that would actually be delivered to the grid.

[4] LA Council File No. 23-0039.

[5] https://www.nrel.gov/analysis/los-angeles-100-percent-renewable-study.html.

As LADWP deploys a greater amount of renewable resources, various studies—including LA100—find much of this renewable capacity will be developed outside of the LA basin and be delivered via transmission capacity that travels into the basin. Among the key findings from the LA100 study was the continued need for "dispatchable" capacity located in the LA basin that provides resilience against transmission failures. This means the LADWP system must have capacity that can operate for extended periods, including during periods of high demand and/or low renewable output, whether because of actual low renewable supply or because the renewable capacity is unavailable due to transmission failure.

Much of this dispatchable capacity in the LA100 study scenarios is provided by combustion turbines burning hydrogen or other renewably derived fuels. All the LA100 study scenarios deploy significant quantities of this technology at all four of the in-basin locations at which LADWP has natural-gas-fired power plants, including Scattergood.

The LA100 study considered a variety of technology options to provide this dispatchable capacity, including the four options considered in this analysis. Some of these technologies—including new transmission delivering energy from new out-of-basin resources, demand response, and energy storage—were deployed in significant quantities in the LA100 study. However, these technologies individually or in combination were not able to replace renewably fueled combustion resources, based on cost, reliability, and other factors.

Since the completion of the LA100 study, there have been some notable changes in technology options—including a decline in energy storage costs. In response to the City Council directive, this study reassessed four technologies: new transmission, energy storage, fuel cells, and demand response, as well as combinations of these technologies. It considered whether there have been sufficient changes to consider them as economically viable alternatives to the very specific case as a replacement for SMP, including their ability to be deployed by the end of 2029.

The remainder of the report is structured as follows: Section 2 describes the basic characteristics of the LADWP system for comparison. Section 3 provides an overview of the technology screening process, Sections 4–7 discuss the four alternatives, and Section 8 discusses the possible combination of technologies. Section 9 concludes, followed by appendices that provide additional details of modeling and cost assumptions for the various technologies considered.

2 Characterizing a Baseline System for Comparison

2.1 Characterizing the LADWP System in 2030

To evaluate the potential role of SMP and alternatives, we first must establish base characteristics of the LADWP system in 2030. This system can then be simulated with SMP and various alternatives. Additional details are provided in Appendix A.

2.1.1 Electricity Demand

Two electricity demand cases were generated. Table 1 summarizes annual energy requirements and peak demand assumed in 2030. These values represent demand, including losses in transmission and distribution (T&D), and are therefore greater than total sales. It is also important to note these values are *before* the contribution of behind-the-meter rooftop photovoltaics (PV). Any contribution from PV therefore reduces the energy and peak demand needs.

Table 1. Demand Assumptions for 2030

Demand Case	Annual Energy (gigawatt-hours [GWh])	Peak Demand (MW)
Low	26,270	6,683
High	30,323	7,667

Values include losses in transmission and distribution; values are before subtracting the contribution of behind-the-meter PV.

Hourly load profiles were obtained from the LA100 study SB100 moderate scenario and scaled to match the values in Table 1.

2.1.2 Resource Mix

The mixes of resources in 2030 (and later years) were based on two cases from the 2022 Strategic Long-Term Resource Plan (SLTRP). The first is from the "SB100" case described as "a reference case based on California Senate Bill 100." The other is "Case 1," which is described as the "recommended" case—one of three "Core Cases outlining various paths that achieve 100% carbon-free energy by 2035." The other two cases in the SLTRP are described as having higher risk and higher cost and are not considered further in this analysis. For each of these two cases, a high and low demand mix was generated, resulting in four total cases abbreviated as SB100-low, SB100-high, Case 1-low, and Case 1-high.

These base cases include SMP, which is a combined-cycle gas turbine consisting of two generation components. The first is a gas turbine (jet engine) capable of burning blends of natural gas and hydrogen. The exhaust heat from this turbine is used to boil water to create steam, which drives a second generator. For modeling and comparison to alternatives, we assume 330 MW net.[6]

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[6] Derated to about 315 MW during periods of extreme heat.

We also assume both cases maintain the existing thermal (gas) capacity—including all generation resources at Haynes, Harbor, Valley, and Scattergood—except for the retiring Scattergood OTC units. We assume the OTC combined-cycle generators at Haynes Unit 8 and Harbor Unit 5 will have new cooling retrofits completed by the end of 2030.[7]

Figure 1 (top) shows the mix of capacity resources in 2030 for the four scenarios. Figure 1 (bottom) shows the generation by resource, which was estimated using the PLEXOS model.[8] Note for this study, the LADWP system was evaluated as an islanded system, without energy exchange with neighboring regions.

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[7] This consists of the Haynes units 8/9/10 and Harbor units 1/2/5.

[8] This model was used in the LA100 study and is described in more detail in the LA100 study report.

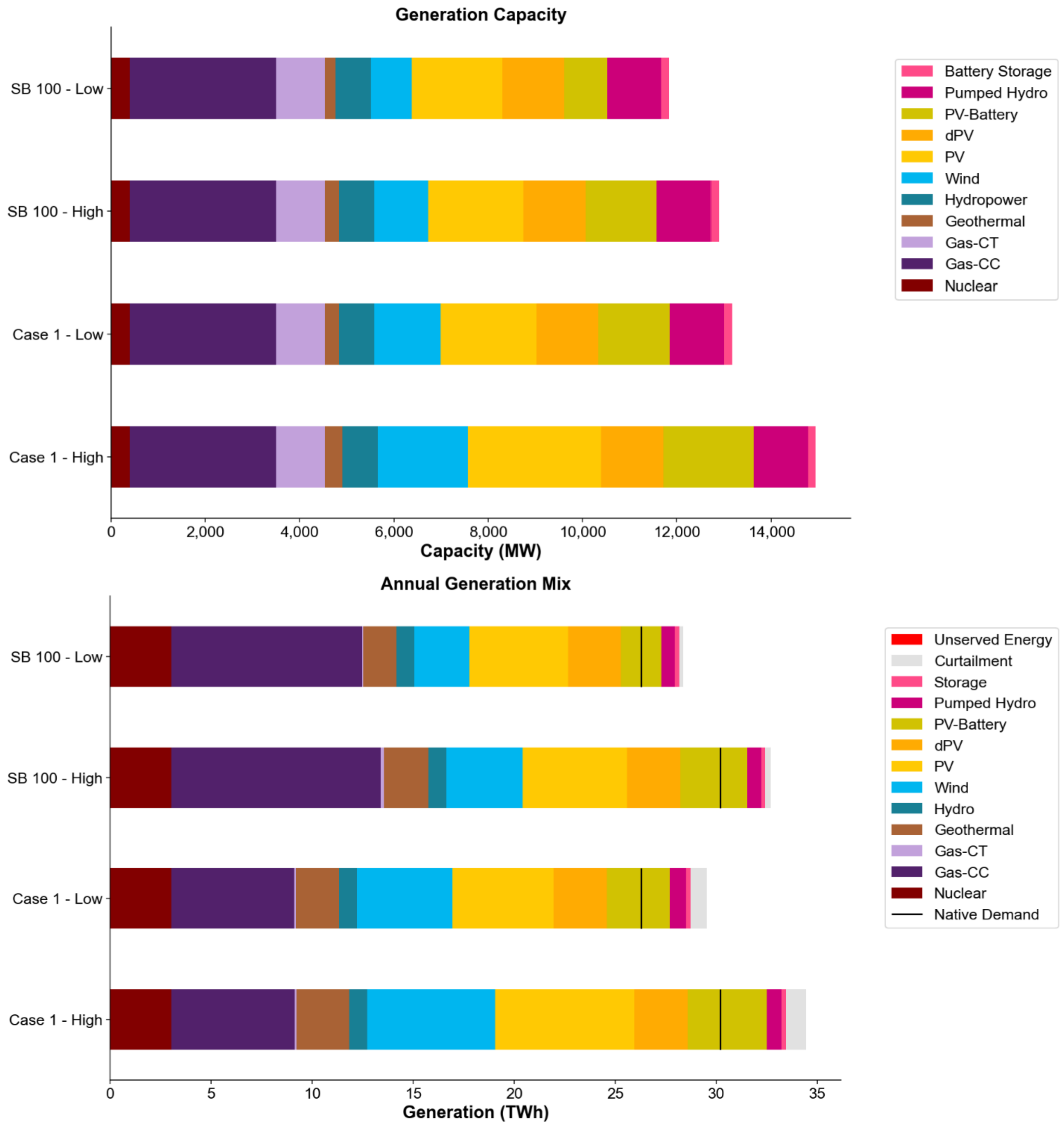

Figure 1. Capacity mix (top) and annual generation mix (bottom) for the four cases in 2030

Assumes islanded system under normal operation, including SMP and without considering the impact of major outages. TWh = terawatt-hours. Gas-CC includes plants with dual fuel capability.

The results in this section represent “normal” operating conditions without significantly unusual events such as transmission outages resulting from wildfires or above-average levels of generator outages. However, the LADWP system must also be robust to a reasonable set of combinations of failures on the transmission and generation system. The contribution of SMP toward maintaining reliability during these types of events is an important point of comparison and is discussed in Section 3.2.

2.2 Operation of SMP in 2030 Under Normal Conditions

The contribution of each generation resource varies significantly on an hourly, daily, and seasonal basis depending on demand and the contribution of various renewable resources. The Scattergood Modernization Project operates in various modes depending on demand, renewable resource, and how much hydrogen is required. Because it is LADWP's more efficient (and lowest emissions) gas resource in 2030, it is typically the first to be called on to generate when there is insufficient renewable supply, especially in scenarios where use of very high cost hydrogen is not required.

Power system operation is often illustrated in the form of a system "dispatch stack," illustrated in Figure 2. This shows a set of 3-day periods of operation of the LADWP power system in 2030 in the Case 1 low-demand scenario. SMP operation is shown as the hatched area and in the line plot below each dispatch stack image. The top figure shows a period of low renewable output. During the middle of the day on December 25 and 27, there is sufficient renewable supply to allow much of the gas-fired capacity to turn off. But there is lower solar output and very little wind on December 26, the SMP turns on to support demand during this period. The bottom shows a period of peak demand. During these periods, some of LADWP's most efficient gas plants operate at full output for multiple days.

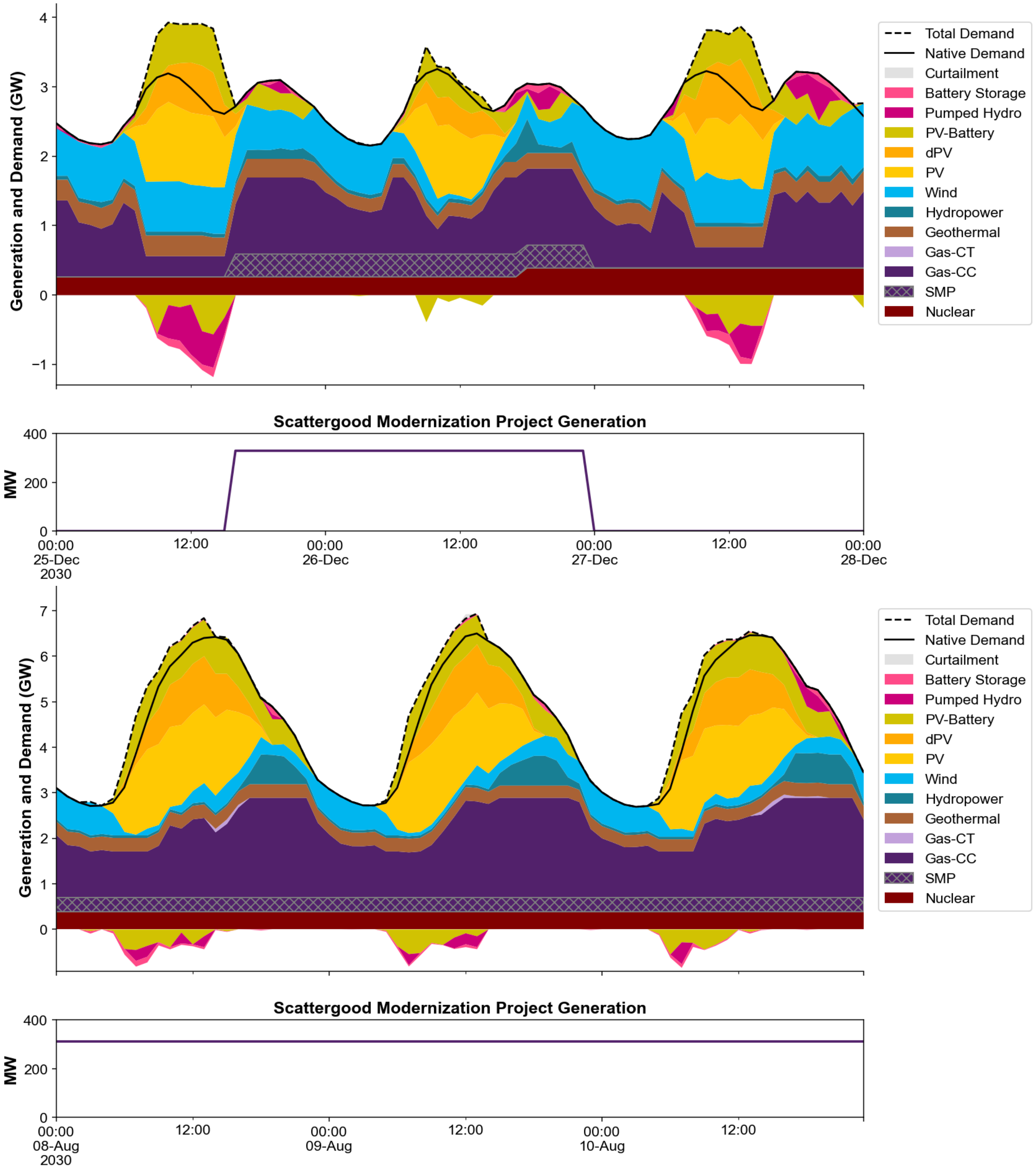

Figure 2. Examples of LADWP system dispatch in 2030 during a period of low renewable output (top), and a period with peak demand (bottom)

Scenarios are from Case 1-low. Gas-CC includes plants with dual fuel capability

The results in this section represent “normal” operating conditions without significantly unusual events such as transmission outages resulting from wildfires or above-average levels of generator outages. However, the LADWP system must also be robust to a reasonable set of combinations of failures on the transmission and generation system. The contribution of SMP toward maintaining reliability during these types of events is an important point of comparison and is discussed in Section 3.2.

2.3 System Resource Mix and Operation Beyond 2030

We focus largely on 2030 because a replacement for the retiring OTC units must be in place by this date to maintain reliability. However, a comprehensive assessment of the relative value of alternatives requires analysis over an extended period. Therefore, we produced a resource mix that follows the approximate trajectory of clean energy deployment of the 2022 SLTRP,[9] shown in Figure 3. This figure shows the fraction of total energy generation (as opposed to total sales).[10] Additional discussion is provided in Appendix A.4.

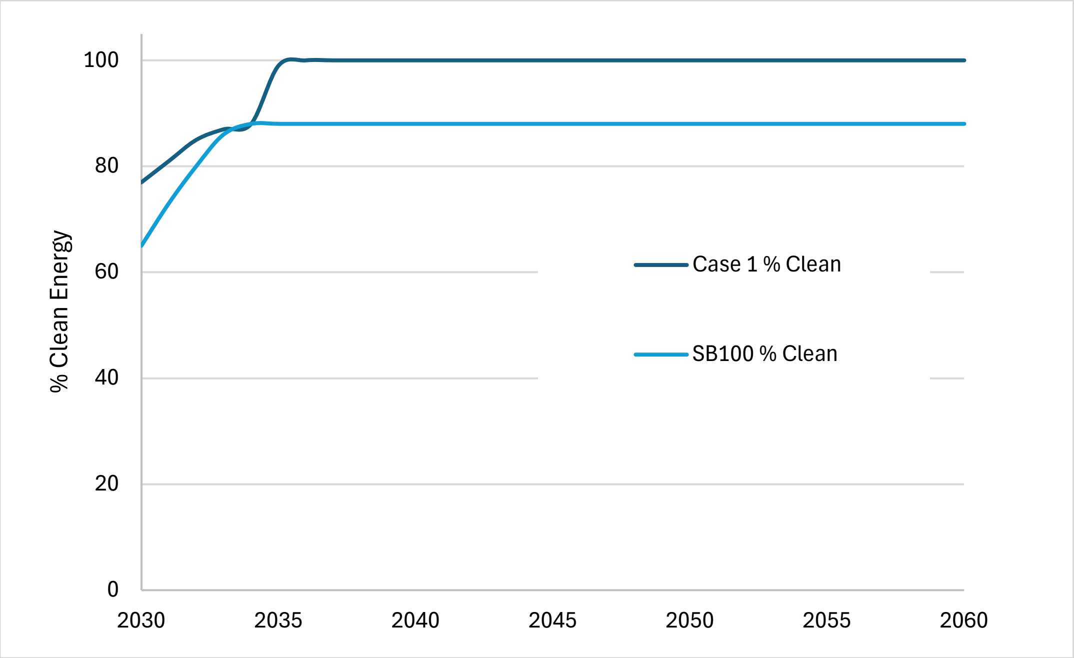

Figure 3. Assumed clean energy mix beyond 2030

Values are constant after 2040.

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[9] See 2022 SLTRP Figure 4-3 and Figure 4-6.

[10] SB100 requires 100% of sales to be provided by clean energy. Assuming a 12% loss rate, this corresponds to about 88% of total generation from clean resources.

3 Characterizing Alternatives and Screening Process

The process of screening and analysis is provided in Figure 4. The first three steps are shown as screening requirements, where if the requirements are not met, the option is not considered for further analysis (meaning analysis in the bottom box is not performed). Each step is described in greater detail in the corresponding section number.

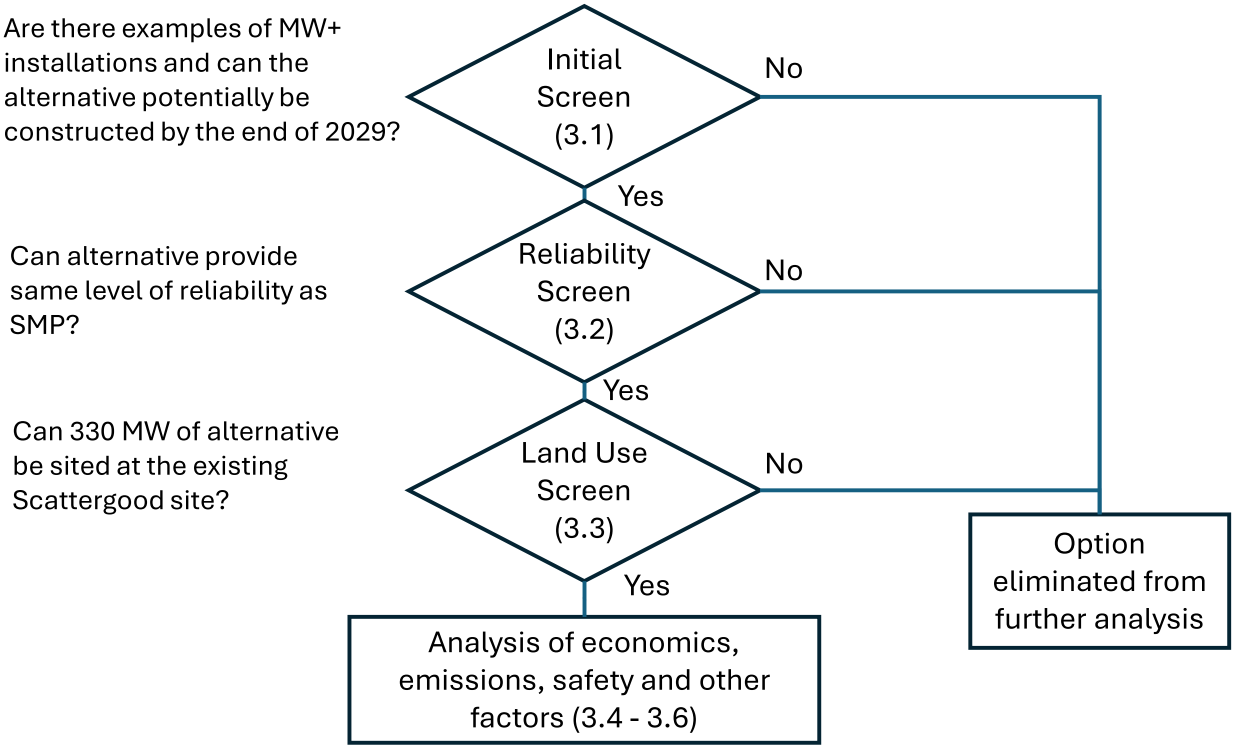

Figure 4. Screening and analysis process for alternatives

Table 2 summarizes the four general sets of technologies discussed in Sections 4–8 as part of this process. Any deployment of these technologies as an SMP alternative would be in addition to those already planned by LADWP.

Table 2. List of Technologies Considered

Technology	Notes
New and upgraded transmission	Detailed set of technologies not considered because transmission in general did not pass the initial screen
Energy storage	11 technologies considered
Fuel cells	4 technologies considered
Demand response	Residential, commercial and industrial demand response (with multiple individual resources within each category) plus electric vehicle managed charging
Technology combinations	Combinations of above technologies discussed in Section 8

3.1 Initial Screen

The initial screen determines if the alternative is commercially available with a demonstrated installed base and can be fully installed and fully operational by SMP's planned in-service date of December 31, 2029. This initial screening must meet two requirements to be considered feasible:

- The technology must have been deployed at multi-MW scale in the United States. This is used to identify (at least in this initial screen) the possibility of a supply chain capable of deploying the option at the scale required.

- The technology must have demonstrated the ability to be deployed in fewer than 5 years from project study/initiation to operational status in the type of urban environment as SMP.

Any option not meeting these two criteria was not evaluated further.

3.2 Reliability Screen

Removing the OTC units (and not replacing them with an alternative resource) decreases the overall reliability of the power system, reflected as increasing likelihood of unserved energy. This means local blackouts for some LADWP customers, with a higher risk to those in the vicinity of Scattergood including Los Angeles International Airport.[11] Reliability of alternatives (that passed the initial screen) was evaluated by simulating various stress conditions and ensuring the alternative can reduce the expected unserved energy to the same level as SMP.

The reliability analysis consists of three components:

- **On-peak availability (probability of a generator outage).** This reflects how often the alternative is unavailable because of required (scheduled or otherwise) maintenance. SMP is expected to be available about 95% of the time. The alternative must be available at approximately this level of reliability—otherwise be potentially derated and have its capacity adjusted to achieve the same level of available capacity.
- **Ability to vary output.** SMP will be required to frequently start and stop and vary output. Although an alternative may not be required to have the same technical characteristics as SMP, an alternative that cannot vary output in response to changing grid conditions might increase overall system costs by requiring more generation from more flexible but higher-cost units.
- **Generate during multihour periods over multiple days under stressed grid conditions.** This reflects the need to have capacity that can operate for extended periods during periods of high demand, such as during hot summer afternoons and other periods of grid stress.

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[11] For this discussion, reliability refers primarily to resource adequacy of the bulk power system or the ability of the generation and transmission system to supply enough energy to its customers. The ability to provide operational reserves was also considered, but this was secondary to the ability of the system to satisfy energy requirements.

Of these three requirements, the ability to generate for extended periods is the most critical—particularly for alternatives such as energy storage and demand response. The LA100 study determined the need for in-basin generation, including replacement of the retiring OTC capacity at Scattergood, based in part on the need to be resilient to failures of the transmission network resulting from wildfires and other events. Much of LADWP's existing and future clean energy generation is imported via several major transmission pathways. However, transmission lines are potentially vulnerable to fires and other natural disasters as well as normal failures that occur with all transmission lines. To evaluate conditions of grid stress, we established two scenarios where parts of the LADWP transmission system are unavailable for extended periods, including during the peak demand season as well as other times of the year. The first scenario is the loss of the Southwest Transmission System (STS), a high-voltage direct current (HVDC) line that runs from central Utah to the border of the LADWP service territory. The second scenario is the loss of multiple lines that could result from a fire similar to the 2019 Saddleridge fire. (Details of the individual lines impacted are provided in Appendix A.5.) In addition, smoke from wildfires is also assumed to reduce solar output by about 7%.[12]

3.3 Footprint Screen

For alternatives passing the reliability screen, the alternatives were screened for the amount of land required. This amount was then compared to the amount available at the Scattergood site. Alternatives that exceed space available were rejected from further analysis, based on the LADWP requirement that the entire capacity of the alternative must be located at the Scattergood site.[13]

The SMP Draft Environmental Impact Report identifies about 10 acres available for development at the Scattergood site in two separate parcels.[14] The land potentially available for an alternative is shown in Figure 5.

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[12] https://www.nrel.gov/docs/fy23osti/86640.pdf.

[13] Based on land acquisition risk and other factors established by LADWP.

[14] https://www.ladwp.com/sites/default/files/2024-10/Scattergood%20Modernization%20Project%20-%20DEIR.pdf

Figure 5. Footprint of site

Image from Google Earth.

The 7-acre southern parcel has irregular shape, and we use a lower value of about 6 acres to account for of potentially unusable area—resulting in a total of 9 acres. The costs of developing this land must be added to the costs of an alternative.

3.4 Economic (Net Cost) Analysis

For alternatives that passed the previous screens, we then performed an economic comparison that considered the *change* in total system costs over a 30-year evaluation period. This cost difference consists of the net present value of two components—fixed costs and variable costs, described in the following subsections.

3.4.1 Difference in Fixed Costs

This category represents the cost of building the plant (capital costs) and fixed operations and maintenance (O&M). For SMP, we used a low and high estimate for the fixed costs of SMP, summarized in Table 3. The costs of the alternatives that passed the screening process are discussed in the corresponding section. This does not include the possibility of a $100 million federal credit that may be possible based on feedback from LADWP (discussed later in this report).

Table 3. Net Present Cost of Adding SMP (Fixed Costs) Assuming $2024

	Estimated Cost (M$)	
Cost Component	**Low Value**	**High Value**
Capital	791	912
Fixed O&M	92	198
Total	**883**	**1,110**

3.4.2 Difference in Operating Costs

It is important to evaluate the difference in the costs of operating the system as a whole—not just the costs of operating SMP or an alternative. This is because each alternative may operate differently and significantly change the operation of the other generators in the LADWP system. This is also why *we do not use levelized cost of energy (LCOE) as a performance metric for comparing SMP to alternatives.* In some cases, the alternative does not produce electricity. In other cases, it is possible for an alternative to have a higher LCOE than SMP but still result in an overall lower cost—or it is also possible for an alternative to have a lower LCOE but result in a higher overall cost, meaning LCOE is of limited use as a comparative metric.

Variable costs are calculated by the PLEXOS model and include three cost categories: the cost of fuel, variable O&M costs, and costs associated with starting and stopping plants.

The total cost of fuel is the product of the cost per unit of fuel ($/British thermal unit [Btu), the fuel consumed per unit of generation (Btu/kilowatt-hour [kWh]), and total generation from gas units (kWh). SMP will be more efficient than most of the other gas plants in the LADWP generation fleet at the time of commissioning. Assumed fuel prices in 2030 are $4.1/MMBtu for natural gas and remains constant over the analysis period.[15] The cost for green hydrogen is assumed to be $30/MMBtu in 2030 declining linearly to $20/MMBtu in 2040.

Fuel costs for all gas plants were assumed to be the same as SMP; other variable costs were provided by LADWP or obtained from NREL's Annual Technology Baseline (ATB)[16] for similar plant types.

To determine the change in operating costs over the 30-year planning horizon, NREL first simulated operations for 2030, 2035, and 2040 either with SMP or an alternative. Results in intermediate years were interpolated, and cost differences were assumed to be constant after 2040—based on the constant fraction of clean energy seen previously in Figure 3.

3.5 Emissions Analysis

For alternatives that passed the screening process, a comparative analysis of carbon dioxide (CO_2) and nitrogen oxides (NOx) was performed. Particularly for CO_2, the most important comparison is systemwide emissions. The impacts of CO_2 on climate change are the result of

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[15] https://www.nrel.gov/docs/fy25osti/92256.pdf

[16] https://atb.nrel.gov/electricity/2024/index

global emissions, and the local or global impacts of climate change are largely independent of the point of origin of CO_2 emissions. Therefore, the analysis focuses on the total emissions resulting from the operation of LADWP's system as a whole. NOx has a more localized impact, so we focus on in-basin NOx emissions from LADWP power plants, noting these plants produced about 0.4% of citywide NOx emissions in 2012.

3.6 Analysis and Discussion of Safety and Other Factors

For alternatives that passed the screening process, several additional factors are discussed. These include potential safety concerns, supply chain, noise, and workforce availability. These issues are discussed primarily in a qualitative manner, especially considering the uncertainty associated with some of the alternative technologies.

4 Alternative 1: New or Upgraded Transmission

4.1 Initial Screen

The LA100 study did not find new or upgraded transmission to be a viable alternative to replace retiring OTC capacity at Scattergood by 2030. Upgraded transmission refers to changes to the existing lines that generally increase their capacity. This includes moving to higher voltages, new conductors that can carry more current, or installation of devices that allow the transmission system to be used more efficiently. All these options can increase the ability of LADWP to accommodate more renewables and decrease LADWP's use of its fossil-fueled generators; LADWP is actively pursuing several of these upgrades.[17] These upgrades were incorporated into the LA100 study as well as the analysis considered here. However, these upgrades do not sufficiently reduce the risk associated with extended outages of major transmission assets during fires or other outage conditions, and any loss of generation from out of basin, would need to be replaced with in-basin generation during these outages.

An important benefit of generation capacity at Scattergood is increased resilience to outages on multiple sets of transmission lines, such as occurred during the Saddleridge fire. Adding resilience to this type of event without replacement capacity at Scattergood would likely require constructing transmission on new pathways not vulnerable to the same event as existing lines. These pathways would largely require a full development process, including siting, permitting, environmental analysis, and installation. To deliver energy to the Scattergood location would require extensive development of transmission within the city (including new right of ways), or the use of offshore transmission. There is insufficient time to develop new transmission.

As a result, new and upgraded transmission does not pass the initial screening criteria and was not considered for additional analysis.

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[17] As discussed in the LADWP SLTRP.

5 Alternative 2: Energy Storage

The original LA100 study included several energy storage technologies; however, only lithium-ion (Li-ion) batteries with 4 or 8 hours of duration were included as an option for siting in the LA basin. The LA100 study found battery storage technologies that could be sited at Scattergood were an uneconomic alternative compared to renewably fueled combustion turbines to replace all the services provided by the existing Scattergood OTC unit.

Since the publication of the LA100 study, there have been both considerable deployment of Li-ion batteries and continued reductions in cost. More than 10 gigawatts (GW) have been installed in California as of August 2024, with another 4 GW either under construction or fully permitted and expected by the end of 2025. At least 51 projects in California with at least 100-MW power capacity have been completed since 2020. There are many examples of projects installed in densely populated areas, including Los Angeles County. There have also been demonstrations of several other storage technologies.

5.1 Initial Screen

NREL screened 10 storage technologies for this updated analysis.

The only storage technology that clearly passed our initial screening (demonstrating multi-MW installations in the United States) is Li-ion batteries. Technologies considered but that did not pass the initial screen are listed in Table 4. It is important to note this screening applies only to the specific case in this study of replacing SMP. These technologies could be options for LADWP for other future applications.

Table 4. Energy Storage Technologies That Did Not Pass the Initial Screen

Technology	Notes
Pumped hydropower storage	Not available at Scattergood location.
Concentrating solar power with thermal storage	Not available at Scattergood location.
Compressed-air energy storage	Not available at Scattergood location.
Thermal/pumped thermal storage	Not commercially deployed at scale.
Liquid air energy storage	Not commercially deployed at scale (no deployments in the United States).
Non-lithium-based battery types (vanadium and other flow batteries, zinc, iron, and sodium)	Several potentially promising battery chemistries could be competitive with lithium-ion batteries when deployed at scale, particularly for longer-duration applications. However, these technologies are all in the early demonstration phase, without multi-MW installations with multiple years of commercial operation, or with multiple vendors potentially representing a robust supply chain. The capacity of *all* utility-scale non-lithium-based batteries completed from 2020 to 2023 in the United

Technology	Notes
	States was less than 30 MW.[18] However, several technologies with recent or proposed demonstration projects warrant continued scrutiny for possible deployments.[19]
Flywheels	Not available with multihour duration.

5.2 Reliability Screen

Energy storage has demonstrated its capability of providing on-demand electricity during periods of high system stress in several regions of the country, including California. Batteries generally have high availability, but detailed data from official sources are not yet available. As a result, we have no basis to assume batteries have higher or lower availability than a gas plant, although the modularity of the batteries could help reduce the odds of an outage of the entire system—particularly if the system consists of independent units.[20] Batteries can operate extremely flexibly, quickly ramping, starting, and stopping (typically with much greater levels of flexibility than gas turbines).

Therefore, the main issue associated with batteries providing reliable operation is limited duration of operation before they need to recharge, and ensuring sufficient generation and transmission capacity is available to recharge the batteries. During periods of peak demand, batteries will recharge largely from in-basin (gas) generation during overnight periods – charging with only renewable energy does not result in reliable operation and is not a feasible alternative.[21] As in the LA100 study, this study found long durations (at least 10 hours) were required to meet the levels of reliability achieved by SMP.

5.3 Footprint Screen

To determine the feasibility of deploying Li-ion batteries at the Scattergood site, we first determined the space required per MW and per MWh of energy storage capacity. We measured the area required for 10 sites in California with installations of at least 100 MW as described in

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[18] Data from EIA 860. Note the installed capacity of non-lithium-based batteries in EIA 860 was significantly higher than 30 MW, but when we checked individual projects, most were actually lithium-ion. We also compared this to the Wood-Mackenzie database, and it estimates the total installed capacity of all nonlithium batteries installed since 2020 is about 24 MW.

[19] Several of these technologies have multi-MW deployments and so technically could be considered to pass our initial screen. Examples include an 18-MW zinc-based battery completed in South Carolina and relatively small (<10-MW) iron-based batteries expected in 2025. However, these technologies have a much greater footprint than Li-ion and therefore would be eliminated from consideration because of lack of space at the Scattergood site as discussed in Section 5.3.

[20] One of the few numbers we found (a 5% forced outage rate) is about the same as a combined-cycle gas turbine. https://www.energy.ca.gov/sites/default/files/2021-09/CEC-200-2021-009.pdf.

[21] One aspect not considered in this analysis is the potential reduced life of certain equipment resulting from overnight charging. Reduced loads overnight allow transformers and other equipment to cool, and additional loading from storage charging would reduce cooling opportunities, potentially increased failure rates or require accelerated replacement and associated costs.

Appendix B. These 10 sites have batteries with 4-hour duration, so we adjusted the requirement for a 10-hour battery.[22]

Table 5 summarizes the results of the analysis using two footprint values. The first row represents potential deployment based on a recently deployed project (2024) with relatively high density, requiring about 33 MW/acre for a 4-hour battery. After scaling this to the estimated requirement for a 10-hour battery (20.6 MW/acre), a 330-MW installation would require about 21 acres of area. If only 3 acres were available (the proposed SMP footprint), the maximum deployable capacity with this density is only about 47 MW; if the full 9 acres were available, the site could accommodate about 128 MW. The second row of the table represents siting characteristics of the highest density project we identified, which increases the potential capacity at Scattergood to as much as 180 MW—but this is still substantially smaller than SMP.

Table 5. Land Requirements for a 330-MW, 10-Hour Battery and Maximum Capacity Deployable at Scattergood Based on Existing 4-Hour Battery Projects in California

Case	Estimated 10-Hour Density (MW/acre)	Area Required for 330-MW, 10-hour Battery (acres)	Potential 10-Hour Capacity at Scattergood (MW)	
			3 Acre	9 Acre
Recent High Density: Cald BESS	20.6	21.1	47	141
Highest Density: Saticoy	25.1	16.5	60	180

Given that there is insufficient land available at the Scattergood site for batteries to provide a full replacement option for SMP, and based on significant uncertainty around the amount of time and process required to locate, obtain full site control and conduct environmental reviews on additional land located near Scattergood, batteries *cannot provide an equivalent alternative to SMP by 2030 and were not considered for further analysis.* Further discussion of batteries deployed as part of a combined solution is discussed in Section 8, with addition material related to battery costs and fire risks provided in Appendix B.

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[22] The original intention was to repeat the footprint analysis for each scenario with corresponding duration requirements. But because the best case (10-hour duration) did not pass the screen, analysis of the other scenarios with longer duration was not necessary.

6 Alternative 3: Fuel Cells

The LA100 study included a "generic" fuel cell technology as an alternative to combustion turbines. However, the technology was found to be uneconomic, and because of high assumed costs, this technology was deployed only after 2040, and in very small amounts in a limited number of scenarios.

Since the publication of the LA100 study, there have been additional deployments of fuel cells. As of September 2024, there were 382 MW of stationary fuel cells installed in the United States and 172 MW in California.[23] The maximum size at an individual site identified is 16.6 MW. Global installations exceed 1 GW.[24]

6.1 Initial Screen

We first screened fuel cells that conform to the city council request, which calls for the consideration of fuel cells that "solely utilize hydrogen that is produced using new, dedicated renewable energy resources or excess renewable energy resources." There are two options for producing sufficient green hydrogen to operate Scattergood on 100% green hydrogen in 2030. The first is to generate and store hydrogen at a remote location with high-quality renewable resources and develop entirely new hydrogen pipelines into the LA basin and to the Scattergood site. However, the time needed to permit and construct these pipelines is greater than the time allowed for completion by the end of 2029. An alternative would be to produce and store hydrogen at the Scattergood site. This would require large amounts of electricity delivered into the Scattergood site, along with storage capacity that greatly exceeds what is feasible at the Scattergood site. Overall, the extensive infrastructure required for fuel cells to operate on 100% green hydrogen at the Scattergood location does not exist and is unlikely to be available before 2030. Therefore, the fuel cell alternative that strictly conforms to the city council request *is likely infeasible and not considered for further analysis.*

However, because the Scattergood Modernization Project begins operation on a blend of hydrogen and natural gas, we also considered the option of fuel cells operating on this fuel mix. We considered four fuel cell types, listed in Table 6, with three passing the initial screen.

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[23] U.S. Energy Information Administration (EIA) Form 860M for September 2024, including capacity of fuel cells greater than 0.1 MW.

[24] https://observatory.clean-hydrogen.europa.eu/tools-reports/datasets.

Table 6. List of Fuel Cell Technologies Screened

Technology	Notes
Molten carbonate fuel cell (MCFC)	Did not pass initial screen. Cannot typically operate on pure H2.
Phosphoric acid fuel cell (PAFC)	Passed initial screen.
Proton exchange membrane (PEM) fuel cell	Passed initial screen. Very limited deployment for stationary applications, but some 1+ MW demonstrations (Largest deployed unit in the U.S. is 1.5 MW)[25]
Solid oxide fuel cell (SOFC)	Passed initial screen—of the types evaluated, SOFC has the largest number of deployments in the United States.[26] (Largest deployed SOFC in the United States is 16.5 MW)

Of these three technologies, PAFC and SOFC can operate on blends of H2 and natural gas (0%–100%). This means these technologies can work directly on the assumed 2030 blend (30% hydrogen by volume, equal to 10% on an energy basis.) PEM requires 100% pure hydrogen and so cannot work on natural gas/hydrogen blends. Therefore, to operate on a fuel blend in 2030, we consider PEM with the use of a reformer, which converts natural gas into hydrogen.[27]

6.2 Reliability Screen

There are limited data on the reliability performance of fuel cells compared to gas turbines. Manufacturer data suggest availability that meets or exceeds 95%, roughly equivalent to a gas turbine. The modularity of the fuel cells could potentially help reduce the odds of an outage of the entire system, particularly if it consists of independent units. We therefore assume the outage rates on fuel cells are similar to SMP.

A unit providing the same level of reliability of SMP must have the ability to vary output and start and stop. PEM can start and stop rapidly and vary output at rates much higher than SMP. However, the reformer needed for PEM to operate on natural gas requires at least 3 hours to start and reach full output. For this reason, we require the PEM installation to have sufficient on-site H2 storage to allow the fuel cell to operate at full output for 3 hours to allow the reformer time to start. Extensive part-load and cycling operation could reduce stack life and are accounted for in this analysis (see Appendix C).

The SOFC is less flexible. It has long start times (typically4–6 hours but can be higher), and each start/stop cycle can reduce the life of the unit. Once operating, each can vary output at rates similar to or greater than those of gas turbines. We allow SOFC to pass the initial screen, but the

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[25] https://blog.ballard.com/powergen/ballard-backed-powergen-project-completes-successful-datacenter-demo

[26] EIA does not report fuel cell type but based on other sources, most of this capacity is in the form of SOFC units (Wood Mackenzie, Stationary fuel cells market outlook, 2024). In addition, EIA lists Bloom Energy as owning more than 131 MW.

[27] This means the fuel cell is effectively using a natural gas/hydrogen blend in the same manner as SMP.

significant impact of starts and stops, or running the SOFC at low output to avoid a shutdown is considered in the economic analysis.

The PAFC is even less flexible because of significant degradation associated with each start/stop cycle. This means the PAFC is largely incompatible with the needs of an SMP alternative; for this reason, PAFC is eliminated from further consideration.

6.3 Footprint Screen

Details of the footprint screen are provided in Appendix B and summarized here.

For PEM, three major components are required: the fuel cell system, the steam-methane reformer (SMR), and storage. Table 7 shows the estimated footprint of each component with detailed discussion and layout provided in Appendix C.2.

Table 7. Area Required for 330 MW of PEM Fuel Cells

Component	Area Required (acres)	Notes
Fuel cell	1.7–1.8	Based on a flat configuration from two vendors
SMR	4.7–6.0	
H2 storage	0.3–0.8	3-hour capacity based on SMR start time
Total	**6.7–8.6**	**Requires development of additional land south of Grand Avenue**

SOFC fuel cells can operate directly on natural gas and so do not require the SMR or fuel storage. NREL estimates a flat layout for SOFC (using Bloom Energy fuel cells) would require about 7.3 acres, whereas a multistory configuration would require 2.2 acres.

As a result, we assume both PEM and SOFC pass the footprint screen, with additional land requirements (greater than the 3 acres allotted for SMP) considered in the economic analysis. However, because of greater uncertainty, we do not consider the multistory configuration for further analysis.

6.4 Economic Analysis

Fuel cells have considerably higher fixed costs than SMP. Figure 6 summarizes assumed net present value of the fixed costs of PEM and SOFC fuel cells along with SMP for comparison. It is important to note there is significant uncertainty in values for fuel cells in the figure; additional details are provided in Appendix C. These median values for the fixed costs of fuel cells are at least twice the median value for SMP.

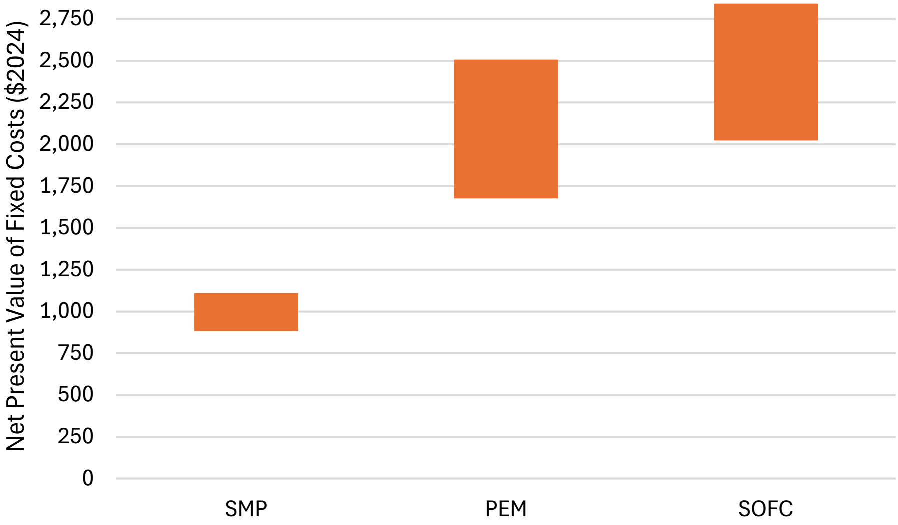

Figure 6. Net present value of fixed costs of fuel cells and SMP over the 30-year evaluation period

The net change in operating costs is calculated using the PLEXOS model by replacing SMP with the fuel cells. The PEM results in higher variable costs because of significantly lower efficiency. Each unit of electricity generated by a PEM will require 1.5 times the fuel used by SMP for the same amount of electricity.[28] As a result, the PEM unit displaces much less electricity from the other natural gas units in the LADWP system compared to the more efficient SMP.

The efficiency of an SOFC is similar to SMP. However, the SOFC incurs additional variable costs associated with starts and stops, and is often operated at low load to avoid a stop, generating electricity when other, more efficient units could be operating instead. Across the scenarios, replacing SMP with fuel cells increases the variable cost of operation by $25–50 million over the 30-year analysis period.

Figure 7 shows the total cost premium associated with replacing SMP with fuel cells. The PEM increases the cost by at least $600 million over the 30-year evaluation period, with a median value of about $1.1 billion. The SOFC increases costs by at least $950 million and a median increase of more than $1.4 billion. These values do not include the possibility of a $100 million federal grant associated with the use of hydrogen fuel at SMP, under the assumption this could be applied to a fuel cell operating with the same fuel mix.

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[28] As a result of the lower efficiency of the fuel cell, as well as the losses in converting natural gas to hydrogen in the reformer.

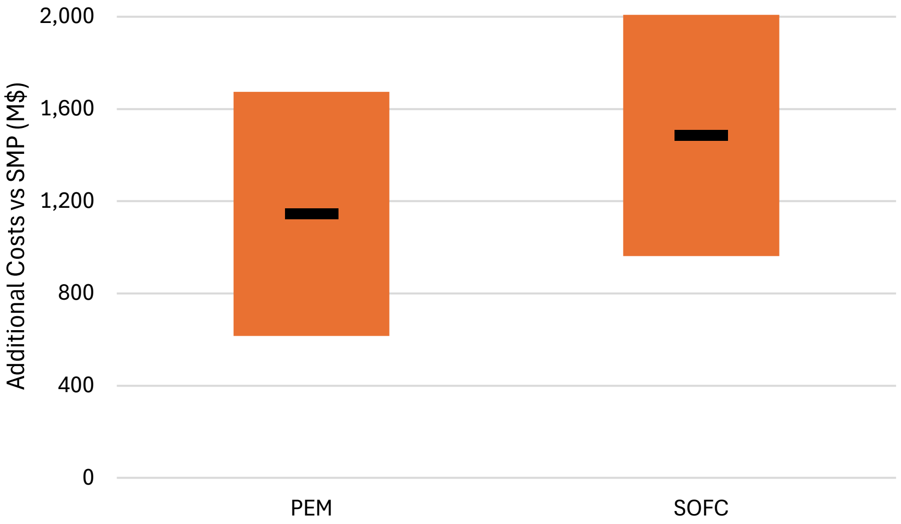

Figure 7. Additional costs associated with replacing SMP with fuel cells over the 30-year evaluation period

Overall, these results support the conclusion from the LA100 study that finds fuel cells to be an uneconomic alternative to a combustion-based resource required to be installed by 2030.

6.5 Emissions Analysis

The use of either a PEM or an SOFC as an alternative to SMP results in a small (less than 1%) *increase* in systemwide CO_2 emissions throughout much of the evaluation period. In the PEM case, it is driven by its lower efficiency compared to SMP. Each unit of electricity produced by SMP requires about 6,574 Btu of fuel. If operating on 90% natural gas (on an energy basis), this corresponds to about 690 pounds of CO_2 per MWh of generation from SMP.[29] PEM requires about 10,943 Btu of natural gas fuel to produce 1 kWh of electricity. If operating on 90% natural gas on an energy basis, this results in 1,149 pounds of CO_2 emissions per MWh of generation (about 1.6 times that of SMP). As a result of the lower efficiency, replacing SMP with a PEM fuel cell increases operation from less efficient gas units.

The SOFC has a higher efficiency than PEM (when running on natural gas) but is still about 13% less efficient, meaning it produces CO_2 at a rate 13% higher than SMP. In addition, the inflexibility of the SOFC fuel cell leads to increased operation of more flexible (but less efficient) gas units.

Replacing SMP with the SOFC results in a roughly equivalent amount of system-wide NOx emissions. Replacing SMP with the PEM increases systemwide NOx emissions by about 1% in 2030. Although PEM fuel cells do not directly produce NOx, the use of SMR produces some NOx. But the primary cause of the NOx emissions increase is the lower efficiency of the PEM

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[29] Assumes a natural gas to CO_2 emission rate of 116.7 lb/Btu. https://www.eia.gov/environment/emissions/co2_vol_mass.php.

fuel cell and resulting increase in operations from other gas units. The SOFC produces a slightly smaller increase in NOx emissions. This increase in emissions resulting from the use of fuel cells decreases over time, particularly as the PEM fuel cell transitions to 100% hydrogen, which eliminates SMR emissions and increases efficiency. However, the fuel cell cases never produce a significant reduction in NOx emissions compared to SMP. Furthermore, it should be noted the very small differences in NOx emissions observed could be greatly impacted by changes in emissions controls or other assumptions. As a result, there is considerable uncertainty in the NOx emission results, but it appears to be very unlikely that fuel cells could produce significant emissions benefits, particularly in the first few years of operations.

6.6 Discussion of Other Factors

In addition to significantly higher costs, there are other challenges associated with fuel cells. Perhaps the greatest is the significant uncertainty regarding installation and operation of a large single installation. Manufacturers surveyed for this analysis indicate sufficient manufacturing capacity exists to support the deployment of 330 MW—with Bloom and Ballard reporting capacity exceeding 1 GW/yr, with no major supply chain concerns reported. However, the largest installation at any site in the United States about 5% of the size required to replace SMP, which suggests potential for unknown construction and supply chain issues associated with deploying a first-of-a-kind plant at this scale at a single location.

The limited size and deployment of fuel cells to date results in other unknown factors regarding safety. Hydrogen-based fuel cell power plants require specific safety considerations because of their distributed fuel architecture, extensive piping networks, and frequent component replacements. These factors increase potential leak points, necessitating engineering safeguards to mitigate risks. Compared to traditional gas-fired power plants (such as SMP), which centralize fuel delivery and combustion, fuel cell systems distribute fuel across multiple stacks—inherently increasing leakage risks because of multiple high-pressure connection points. Although large-scale comparative data remain limited, qualitative and semi-quantitative risk assessments indicate distributed hydrogen systems require additional safety redundancies to address these challenges. Appendix C provides additional details, but we must emphasize a single 330-MW fuel cell installation has not been deployed at a single location, so quantification of safety and other issues is not possible at this time.

Other issues include training operators and maintainers on this technology, which is fundamentally different from gas turbines. LADWP operates multiple gas turbine power plants, including the existing combined-cycle plant at Scattergood, which is similar in size to SMP. Except for the hydrogen component, SMP would be similar to the existing plants and could therefore leverage capabilities of existing skilled workers.

Some of these factors may increase the risk of decreased project performance, such as lower availability; others increase the risk of higher installation or operational costs. Overall, there are insufficient data to quantify these impacts—however, they generally support that the estimates provided in the economic analysis (especially for PEM) likely represent a lower bound and fuel cells represent a significant cost premium over SMP in the 2030 time frame. Further discussion is provided in Appendix C.

7 Alternative 4: Demand Response

Demand response (DR) represents a fundamentally different approach to maintaining system reliability compared to supply-side resources, such as generators. Demand response refers to the ways utilities or grid operators can harness demand flexibility, often to reduce demand during periods of high grid stress. These programs typically call for participation from demand-side resources for a limited duration of time on an intraday basis. They are generally voluntary, and participation is compensated.

Examples of DR programs include time-variant pricing—such as real-time, time-of-use (TOU), and critical peak prices—to encourage demand-side participation and better align electricity demand and supply.[30] Other programs use incentives to enroll customers in programs that facilitate, for example, load reduction during DR events or electric vehicle managed charging, and include performance-based rewards for supporting grid operations.

There are many examples of utilities and system operators using DR as a reliable and dependable alternative to generation resources. Demand response is specifically included in many utilities' resource planning. Demand response is eligible to participate in several independent system operator/regional transmission organization (ISO/RTO) capacity, energy, and ancillary service markets, and the North American Electric Reliability Corporation (NERC) considers DR a reliable source of capacity in its long-term reliability assessments.[31] An overview of these programs is provided in the supplemental demand response appendix.

The 2022 SLTRP (now called LA100 Plan) also includes about 350 MW of demand response.[32] This means to replace SMP, LADWP would need to obtain at least an ***additional*** 330 MW of DR, or a total of about 680 MW. Furthermore, this additional 330 MW of DR would be required for a sufficient duration and equivalent level of reliable response. This means to get 330 MW of reliable, long-duration demand reduction may require more than 330 MW of actual DR participation. This was considered in the reliability screen. The LA100 study included DR from all sectors, with different levels of technical potential and participating resource by load projection. The 2030 Moderate projection (which is the closest to LADWP's current higher-load scenario) identified about 650 MW of on-peak demand response, which is close to the amount required to replace SMP. However, this value from the LA100 study does not include the duration required, how much of this could be sited near the Scattergood location, and several other factors that must be addressed before DR can be considered an alternative to SMP.

7.1 Initial Screen

NREL used several approaches to identify the deployable DR resource by 2030, which are summarized here and described in more detail in the supplemental demand response appendix. The first was a top-down approach leveraging 2023 EIA Form 861 data. In addition to total

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[30] Alstone et al. 2017; Durvasulu and Hansen 2018; Parrish et al. 2020; Asadinejad and Tomsovic 2017; Pourramezan and Samadi 2022.

[31] NERC 2023.

[32] LADWP Demand Response Program Development, Ronak Chikhalya, 10/22/2024. Note LADWP informed NREL that SLTRP has been renamed LA100 Plan during the course of this study and includes greater demand response targets of approximately 435 MW by 2030 driven by capacity shortfalls from IPP downsizing.

customers, retail sales, and revenues by sector, EIA Form 861 reports DR potential and actual peak demand reduction, as well as customers enrolled and cost, by sector for every utility in the United States. A total of 25 utilities similar to LADWP that operate DR programs were identified. Along with LADWP, their DR resource and use data were normalized by the energy sold in total and per sector. LADWP's achievable DR was then estimated based on the assumption LADWP could match the 90th percentile of these historical observations.[33] This provides a conservative estimate of achievable DR because it assumes DR resource and use in 2030 will look similar to today's and serves as a comparison value for the more granular bottom-up approach that is more able to account for technological change. These results, which do not include estimates of EV managed charging potential, suggest about 347 MW of DR is achievable by LADWP across the residential, commercial, and industrial sectors. The scale is comparable to LADWP's goals for 2030 as outlined in the DR RFP.

NREL also performed a bottom-up analysis by analyzing commercial, residential, and industrial loads by end use as well as electric vehicle managed charging, accounting for both the magnitude and potential flexibility of each end use. Results for the entire system (not just DR located near the Scattergood location) are summarized in Table 8. This DR would need to provide both the SLTRP goal and (in addition) the amount required to provide an alternative to SMP. The supplemental DR appendix provides additional details.

Table 8. Estimated Achievable System-Wide DR Potential by 2030

Sector	**Achievable DR Potential (MW)**
Residential	200–350
Commercial	80–140
Industrial	90–150
Electric vehicles	60–145
Total	**350–700**

The lower bound of Table 8 is roughly equal to the 2022 SLTRP goal and would therefore not provide any additional DR to provide an alternative to SMP. However, the higher value is generally similar to the DR potential values found in the LA100 study and does provide sufficient potential to pass the initial screen.

7.2 Reliability Screen

The upper bound of achievable DR identified in the initial screen could reduce demand in the LADWP service territory by at least 330 MW. However, this amount of DR cannot provide the

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[33] Uses data from the U.S. Energy Information Administration (EIA) Form 861 (U.S. Energy Information Administration 2023).

same level of reliability services as SMP because of factors including the required duration and location.

As noted in the discussion of energy storage, under extended outage scenarios, at least 10 hours of continuous discharge was required. For DR, this would require continuous load reduction over this period. Based on NREL's survey of existing programs, this type of DR program is largely unprecedented. We identified some potential candidates for this service; for example, some light-duty and medium-/heavy-duty electric vehicle charging could be deferred for this length of time. However, most of the shiftable loads identified in the bottom-up analysis cannot shift loads over this multihour period. Furthermore, an insufficient amount of demand response potential is located near the Scattergood site. The required reduction represents approximately 5% of peak load, equivalent to 5% of customers eliminating their entire consumption for roughly 9 hours (or 10% of customers halving their usage, etc.).[34] However, the majority of load reduction needs are concentrated near the Scattergood site, where there are an insufficient number of customers with flexible load capabilities.

Therefore, because of the duration and location requirement, demand response, by itself, *cannot provide an equivalent alternative to SMP and was not considered for further analysis.*

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[34] This target could be achieved by enrolling about 20% of total commercial load in a demand response program with a >45% response rate, combined with utilizing 50% of the industrial technical potential and 50% of the electric vehicle managed charging capacity over a 9-hour period.

8 Alternative 5: Combinations

There are potentially many combinations of alternatives that could be studied, but using the same screening methodology discussed in Section 3 eliminates several options. For example, combinations that involve new transmission are likely not viable because of the long development time required for new transmission.

One possible combination that might be technically feasible is the deployment of a combination of fuel cells, storage, and demand response. Figure 8 shows an example of two combination cases that pass the feasibility, reliability, and footprint screens. The first bar is the cost premium with a 330-MW SOFC, using the values shown previously in Figure 7. The next three bars show a case where 330 MW of SOFC is replaced with 230 MW of SOFC (placed on the main 3-acre site), whereas a 100-MW, 8-hour battery is placed on the parcel of land south of Grand Avenue. The combination would reduce the high cost of fuel cells while allowing for some deployment of energy storage at the Scattergood site. The use of dispatchable capacity at the Scattergood site (230 MW of fuel cells) also slightly reduces the duration of storage required to provide the same level of reliability as SMP compared to the storage-only option. The battery has lower capital costs per unit of capacity compared to the fuel cell. The storage is also potentially eligible for the investment tax credit, however given uncertainty, three different ITC values are evaluated: zero, 30% and 40%. Additional discussion of battery cost assumptions is provided in Appendix B.2. This combination would reduce the overall additional cost of the alternative by about $400–600 million compared to the case with just the SOFC. Note the higher cost SOFC (relative to the PEM) must be used in this example because the lower cost PEM requires additional land, so PEM + storage combinations exceed the space allowed.

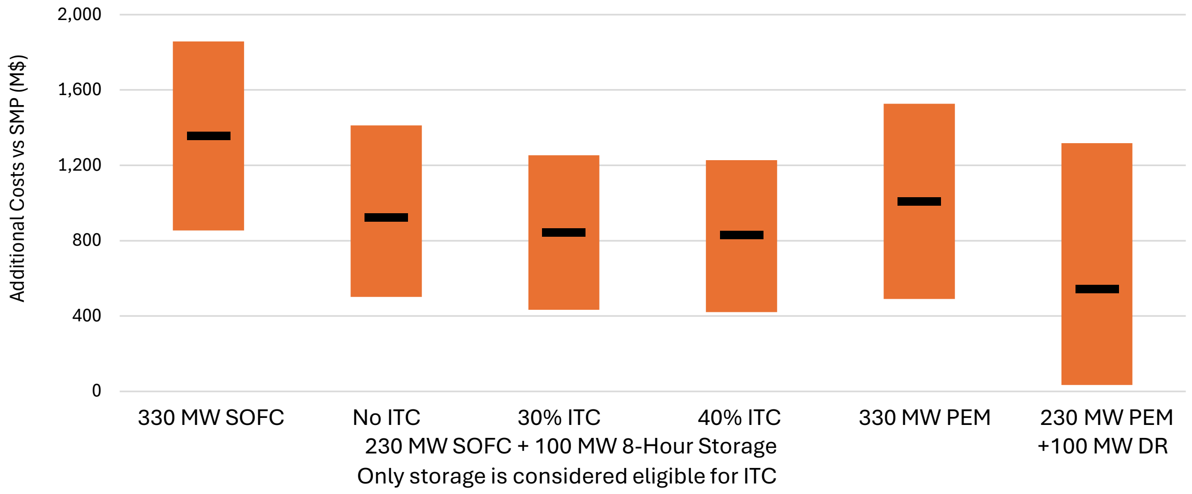

Figure 8. Additional costs associated with replacing SMP with only fuel cells, or a combination of fuel cells plus energy storage or demand response over the 30-year evaluation period

Although this combination reduces costs, it still represents a significant cost premium, with a median value of more than $800 million in additional costs compared to SMP. The limited amount of land available at Scattergood limits the potential for energy storage, and no combination of fuel cells and storage that can be sited at the Scattergood site has a lower cost than SMP. The options that include storage result in slightly reduced CO_2 and NOx emissions compared to the fuel cell only option, but this reduction is very small, and overall reduction in emissions compared to SMP is less than 1%. The large-scale deployment of storage at this site also raises additional considerations such as the need to mitigate against fire risks, as discussed in Appendix B

The last two bars compare a case with just PEM (again, a duplicate of the values in Figure 7) and a case with a combination of 230 MW of PEM and 100 MW of demand response. An overview of demand response cost assumptions is provided in the supplemental demand response appendix. The combination reduces the median cost premium by more than $400 million, but this combination still has a median cost premium of more than $550 million compared to SMP.[35] There are no significant emissions benefits in the combination cases with DR relative to SMP.

Overall, we identified no combination of fuel cells, storage, or demand response that were both feasible (based on the siting requirements or demand response availability) and had lower cost than SMP. These combinations also do not significantly change the emissions results compared to the fuel-cell-only cases. **It is important to acknowledge that all risks and limitations associated with individual technologies apply when the technologies are combined**. For example, while a combination with a 230 MW fuel cell is less than 330 MW, this is still roughly ten times the size of the largest single fuel installation in the United States.

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[35] This assumes an annual cost of demand response of 21.8 $/kW (low), $102.2 $/kW (median), and 372.5 $/kW (high). Additional discussion of the cost of demand response is provided in the separate demand response appendix.

9 Conclusion and Discussion

Potential alternatives to SMP offer a number of risks, benefits, and challenges. Significant challenges include the short time frame available, limited land availability, and limited utility experience with several technological options. Based on the analysis performed by NREL using data, information, and requirements provided by LADWP, combined with data from technology vendors and other peer-reviewed datasets, this study identified several key findings:

1. **There is a need for dispatchable capacity near Scattergood.** To maintain reliable service and increase resilience against transmission outages, new dispatchable capacity is needed to replace the retiring OTC units at Scattergood.
2. **New or updated transmission cannot replace the retiring OTC units in the required time frame.** Historical data indicate it takes significantly more than 5 years to site and build new transmission, leading to the conclusion that options that depend on new transmission are not feasible by the end of 2029.
3. **Fuel cells using 100% green hydrogen are unlikely to be a viable alternative by 2030.** The extensive quantity of fuel and associated infrastructure required for fuel cells to operate on 100% green hydrogen at the Scattergood location (including pipelines and fuel storage) does not exist and is unlikely to be available before 2030. Fuel cells using hydrogen/natural gas blends may be a technically viable alternative but at a significant cost premium and with negligible emissions benefits. In addition, the largest existing installation in the United States is less than 5% of the capacity required to replace SMP, raising concerns about supply chain constraints, manufacturing scalability, and the feasibility of constructing a first of a kind facility of this scale in the time frame required.
4. **Energy battery storage requires more space than is available at Scattergood.** A battery installation with sufficient duration to provide the same level of reliability as SMP would require more land than is available at the Scattergood site. Based on the requirement that full capacity be installed at the site, batteries cannot provide an equivalent alternative to SMP.
5. **Demand response alone is not an adequate alternative.** Although DR can be used to reduce demand at peak times, NREL did not find adequate additional DR capacity, with sufficient duration near Scattergood, to provide an alternative with the same level of reliability as SMP.
6. **Combination options can reduce the cost premium of the alternatives but are still likely more expensive and do not eliminate technology risks.** NREL identified several combination options that would cost less than an alternative consisting of a single option. These options include a combination of fuel cells and storage or a combination of fuel cells and DR. Although these can reduce the cost premium associated with the fuel cells, these combinations are still substantially more expensive than SMP, do not produce significant emissions reductions, and do not eliminate technology risks associated with large-scale fuel cell deployments.

Overall, although there will be continued technological improvements and cost reductions in several alternatives, this analysis finds renewably fueled combustion turbines are likely the lowest-cost and lowest-risk option in the 2030 time frame.

It is important to note the findings of this report are specific to replacement of the retiring Scattergood OTC units by the end of 2029. This report does not replace or inform appropriate system planning as part of LADWP's planning process, which considers the larger portfolio.

Appendix A. System Assumptions

A.1 2030 System Capacity

The assumed capacity in 2030 for the four scenarios is listed in Table A-1. While based on the 2022 SLTRP, the exact mix and locations are not specified in the SLTRP; therefore, the NREL scenarios do not exactly conform to the 2022 SLTRP.

Table A-1. 2030 Installed Capacity: Islanded System Before the Addition of SMP or Alternatives

Resource	Installed Capacity (MW)			
Category	SB100-low	SB100-high	Case 1-low	Case 1-high
PV Rooftop	1,320	1,320	1,320	1,320
PV Tracking	1,929	1,929	2,029	2,029
PV+Battery (PV)	545	945	945	1745
PV+Battery (Battery)	366	566	566	966
Wind	863	1138	1,413	1,913
Generic Storage	167	167	167	167
Geothermal	224	224	299	374
CC	2,798	2,798	2,798	2,798
CT	1,043	1,043	1,043	1,043
Hydro	735	735	735	735
Nuclear	387	387	387	387
Pumped Hydropower Storge	1,150	1,150	1,150	1,150
Total	11,526	11,577	12,851	14,627
Total Low Carbon	7,685	8,736	9,010	10,786
Total Renewables (including hydro)	7,298	8,349	8,623	10,399

A.2 Generator Characteristics

Performance characteristics of thermal generators, including capacity, heat rate, ramp rate, start time, and variable O&M were obtained from LADWP or from publicly available databases such as EIA 923. In most cases, they are very close to the values used in the LA100 study.

Solar and wind profiles were obtained from the LA100 database.

The model includes the provision of operating reserves, including contingency spinning and non-spinning reserves, regulation, and a flexible ramping reserve. Required quantities were calculated using the approach described in LA100.

A.3 Assumed Cost and Performance of SMP

We use two values for the capital cost of SMP. The lower value uses the NREL ATB. It assumes $1,848/kW (after adjusting to $2024), for a plant beginning construction in 2026, using an H frame 1x1 configuration, assuming installation in an "average" cost region of the United States in 2029. The NREL ATB applies a 1.18 multiplier for this plant installed in Southern California, resulting in a cost of $2,181/kW. This is further adjusted to hydrogen-ready capacity using a 10% increase based on EIA estimates, or $2617/kW. Data from LADWP (adjusted to $2024) uses an estimate of $2764/kW, which is higher than the NREL value and used as the upper bound.

For fixed O&M, the lower value from LADWP assumes a value of about $20/kW-year, while the upper range value assumes $45/kW-yr. This is translated into a net present cost, assuming a 30-year project evaluation period, and a discount rate of 5.5%.

Table A-2 lists assumed values for variable costs of SMP operation.

Table A-2. Variable Cost-Related Values for SMP

Parmeter	Value	Notes
Variable O&M	$2.5/MWh	
Heat Rate	6,574 BTU/kWh	At full load. Heat rate is higher at lower loads. Assumed min generation level is 147 MW.
Natural Gas Fuel Cost	$4.1/MMBTU	Remains constant
Hydrogen Fuel Cost	Varies over time	$30/MMBtu in 2030, falling to $30/MMBtu in 2040.
Start Fuel	128 MMBTU	
Non-Fuel Start Cost	$22,000 per start	

A.4 System Resource Mix and Operation in 2035

Table A-3 lists installed capacity in 2035.

Table A-3. 2035 Installed Capacity: Islanded System Before the Addition of SMP or Alternatives

Resource Category	Installed Capacity (MW) SB100-low	SB100-high	Case 1-low	Case 1-high
PV Rooftop	1,320	1,320	1,320	1,320
PV Tracking	1,929	2,029	2,029	2,029
PV+Battery (PV)	545	945	945	1,745
PV+Battery (Battery)	366	566	566	966
Wind	863	1,138	1,413	1,913
Generic Storage	167	167	167	167
Geothermal	224	299	299	374
CC	2,798	2,798	2,798	2,798
CT	1,043	1,043	1,043	1,043
Hydro	735	735	735	735
Nuclear	387	387	387	387
Pumped Hydropower Storge	1,150	1,150	1,150	1,150
Total	11,526	12,851	12,851	12,851
Total Low Carbon	7,685	9,010	9,010	9,010
Total Renewables (incl. hydro)	7,298	8,623	8,623	8,623

Figure A-1 provides the approximate fraction of fuel derived from H_2 in the two cases. Energy fraction is shown on a percentage energy basis. The SB100 requirements do not require large amounts of hydrogen combustion at SMP to achieve 88% clean energy.

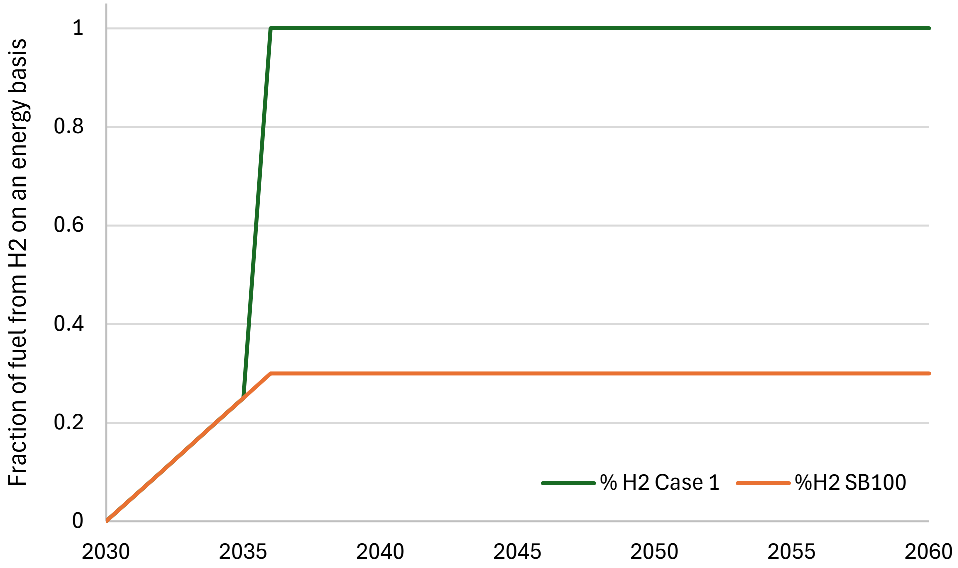

Figure A-1. Assumed hydrogen blend (on an energy basis)

Clean energy mix based on 2022 SLTRP. Hydrogen blend is an estimate based on requirement to meet clean energy trajectory.

A.5 Reliability Cases

The reliability cases simulate the impact of wildfire, which removes transmission elements listed in Table A-4. In addition, these cases assume a normal level of other plant outages, accounting for about 500 MW of thermal capacity, a 7% reduction in solar output due to smoke and haze. We assume no access to outside market generators during peak demand periods due to high demand across all of California

Table A-4. Wildfire Reliability Cases Evaluated

Case	Description
Saddleridge Fire	Loss of transmission during the 2019 Saddleridge Fire: Pacific DC Intertie (PDCI) bipole, Adelanto-Rinaldi, Victorville-Rinaldi, Haskell-Sylmar, Haskell-Olive, Castaic-Northridge, Haskell-Rinaldi, Owens-Gorge, Inyo-Barren Ridge, and San Francisquito Power Plant and Power Plant-Haskell lines
STS	Loss of STS
STS+Inyo	Loss of STS plus all Inyo lines

Appendix B. Battery Analysis

B.1 Footprint Analysis

To determine battery footprint requirements, we rely on direct measurement of actual projects. We identified six sites in California with installations of at least 100 MW that are also located in populated regions (listed in Table B-1). Five are located in Southern California. We then used Google Earth to measure the perimeter of the site and calculate its area. We define the footprint of the site as including all battery modules and power-related equipment (inverters). In some cases, we include equipment related to the substation, which is potentially redundant, as the substation equipment is required by all technologies, and the substation equipment associated with the SMP is not included in the allocated 3-acre site. However, including this equipment allows for some potential errors in our approach.

Figure B-1. provides an example for the 100-MW, 400-MWh Cald BESS, located in Florence-Graham, an area just outside of LADWP service territory in Los Angeles County. We estimate the area occupied by this battery as about 3 acres, so it is very close to the SMP site in size. As a result, this may be one of the best examples of a similar siting situation to Scattergood—it is in an urban area, surrounded on all sides by roads and occupied infrastructure, and installed in 2024, potentially representing state-of-the art technology and recent siting requirements and codes.

Measure the distance or area of a geometric shape on the ground

Perimeter: 0.40 Miles

Area: 12,301.69 Square Meters

☑ Mouse Navigation

Figure B-1. Example of footprint analysis for Cald BESS

Image from Google Earth.

In this example, the site occupies about 3 acres, meaning a density of 32 MW/acre for 4 hours. We found three sites that have a higher density than this project; the highest is the Saticoy facility installed in 2021 at about 40 MW/acre.

Table B-1 lists the six projects evaluated and their footprints. Note that all the projects have a duration of 4 hours. To adjust for additional duration requirements, we estimated the amount of space required for the energy-related components and then scaled the footprint accordingly. Based on a subset of projects evaluated, the space required for a 10-hour battery is about 2–2.1 times that of a 4-hour battery, which means that the area required to support a 100-MW, 4-hour battery would only support a (approximately) 50-MW, 10-hour battery.

Table B-1. Evaluated Battery Projects for Footprint Analysis

Name	Location	Op. Year	Power (MW)	Energy (MWh)	Area (Acres)	Density (MW/acre)
Cald BESS	Florence-Graham, (33.955872,-118.232100) (Los Angeles County)	2024	100	400	3.04	32.9
AES ES Alamitos, LLC	Long Beach (33.770202, -118.099700) (Los Angeles County)	2021	100	400	2.96	33.7
Diablo Energy Storage	Pittsburg (38.028792,-121.900600) (Contra Costa County)	2022	200	800	5.44	36.8
Separator (Etiwanda) BESS	Rancho Cucamonga (34.092110,-117.534000) (San Bernardino County)	2024	112.5	450	4.03	27.9
Condor Energy Storage LLC	Grand Terrace (34.020478,-117.332400) (San Bernardino County)	2024	200	800	6.80	29.4
Saticoy	Oxnard (34.256691, -119.157300) (Ventura County)	2021	100	400	2.50	40.1

B.2 Cost Analysis

For the capital cost of the batteries, we examined two sources: the NREL ATB (2024) and Wood Mackenzie (2024). Figure B-2 shows cost projections from these two sources for a 4-hour battery.

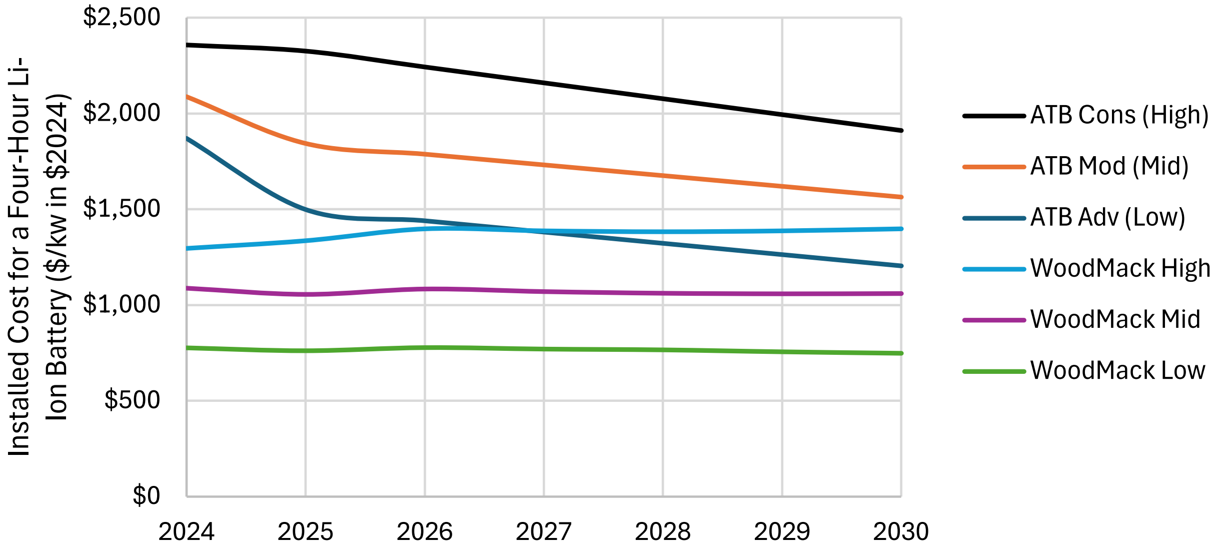

Figure B-2. Battery storage cost projections for a 4-hour battery in an “average” location

The energy and power-related components were isolated to generate a cost as a function of duration, shown in Figure B-3 shows the assumed cost of batteries installed in Southern California in 2029, using a 1.08 multiplier to reflect higher costs.

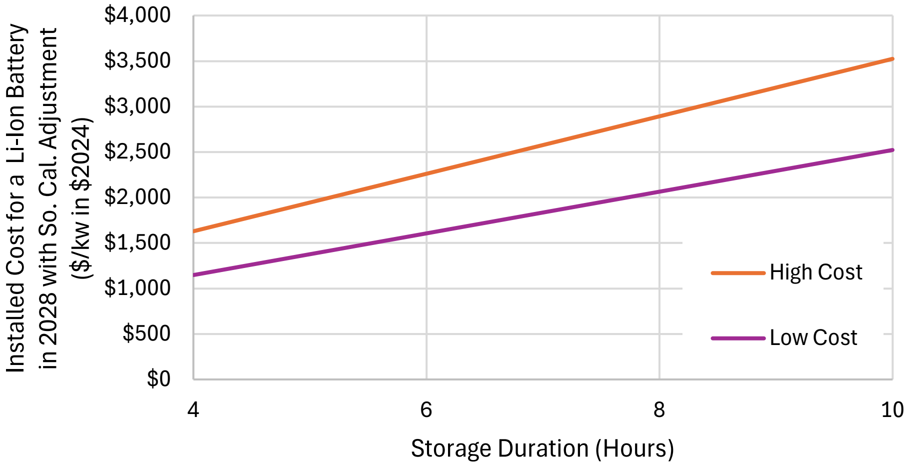

Figure B-3. Assumed cost of Li-ion batteries installed in 2029 in Southern California

We then apply a 1.04 multiplier for the construction financing factor and a 0.7 multiplier for the project finance factor, the latter accounting for the 30% investment tax credit. The tax credit applies only to the initial fixed costs, and no additional fixed costs.

This cost does not account for the difference in lifetime between SMP and a battery. To obtain a 30-year life, we calculate the net present cost of replacing the battery modules at year 15 (2045). For the battery module replacement cost we use the NREL ATB mid cost of $179/kWh in 2045 ($2022).

We use ATB-mid values for fixed O&M, with a 1.08 multiplier for a California premium. The ATB assumes variable costs associated with 1 cycle per day are rolled into fixed O&M. That means the only variable costs associated with storage operation are the costs of charging energy. This stored energy then displaces other generation when discharged, and the change in fuel purchases then captures the total net variable cost of storage plant operation, which is typically a negative value. This negative cost (benefit) results from storage being able to charge with low-cost energy, from otherwise curtailed renewable energy or the most efficient thermal lants, and then discharging to reduce output from the highest cost thermal plants. This net change in operating costs is calculated using the PLEXOS model.

Operational savings associated with the battery (per unit of capacity) are substantially higher than with SMP due to the ability to the battery to charge with lower cost energy. Note that the battery does *not* charge exclusively with renewable or low-carbon energy sources. To maintain reliability the battery must be able to charge with whatever resource is available at lowest cost, especially during periods of system stress.

B.3 Minimizing Battery Fire Risks

Stakeholders should be aware of fire risks—and other issues—related to grid-scale, stationary lithium-ion (Li-ion) batteries.

The risk of thermal events varies depending on device, so it is important to distinguish grid-scale energy storage from electric vehicles (EVs) and from micromobility devices. Presently, data indicates micromobility devices present the greatest risk of injury while EVs and stationary installations present the least relative risk.

For grid-scale energy storage, first responders have the highest exposure to immediate life safety hazards. As such, adequate training about hazards—including the risks posed by fire and explosion—is paramount. Current best practices for lithium-ion batteries include allowing fires to burn and preventing fire propagation to other units. The U.S. Department of Transportation 2024 Emergency Response Guidebook is a good source for first responders.

Research and development of li-ion battery technology is rapid, so while code standards are catching up, there is a gap to close. As codes continue to evolve, the risks of thermal events in li-ion batteries for existing and planned installation can be mitigated. For energy storage system safety, NFPA 855 (2023 Edition) is the current standard with consensus among fire departments, battery manufacturers, R&D, testing agencies, insurance, special experts, and other key stakeholders. NFPA 855 allows Authorities Having Jurisdiction to review existing installations and require modifications if any notable safety issues exist. For planned installations, the latest edition of NFPA 855 provides the best current practices.

It is important to consider environmental and toxicity issues related to li-ion battery thermal events. The U.S. Environmental Protection Agency monitors such events and performs air monitoring and water runoff testing, with conclusions and recommendations still to be made. However, present data suggest that there is limited hazard exposure to the public.

In li-ion batteries, thermal runaway and cell propagation pose fire risks. Failure of a single cell can lead to thermal runaway and cause cell to cell propagation. One issue affecting runaway propagation is separation between cells, modules, and racks. In 2024, a Vistra Corp. energy storage facility in Moss Landing, California, burned for several days. Dedicated use indoor facilities—like the Moss Landing facility—may lack adequate separation between racks of batteries. The Moss Landing facility is an anomaly, as most grid-scale energy storage system facilities currently use individual outdoor containers, which can be sufficiently separated to limit the size of any single incident to a container, as evidenced by fire containment to one storage container at a 2024 fire in San Diego Gas and Electric's battery storage facility in Escondido, California. The fire department responded and cooled adjacent exposures, as directed by the Emergency Response Guide. The fire department avoided explosion hazards and protected exposures from fire spread. Once the container finished burning, the incident was over.

Vistra's facility was designed using older battery safety codes and standards. The first edition of NFPA 855 (2020 Edition), was released in August of 2019, after California regulators approved the utility contract for Moss Landing in November 2018. In addition, the 2019 California Fire Code, based on the 2018 International Fire Code, was adopted in California on January 1, 2020. The Vistra project was in the latter stages of development at this time. While the project reflected the industry's best insights at the time, subsequent editions of both NFPA 855 and the International Fire Code have built upon lessons learned over the years.

One recent development that is intended to mitigate thermal runaway propagation hazards in energy storage systems is the development of what are called Thermal Runaway Propagation Protection (TRPP) systems. These are systems that are often installed at a module level within an ESS and validated via testing to demonstrate their ability to limit cell to cell propagation. The upcoming 2026 Edition of NFPA 855 will be the first standard to address these technologies and will provide new requirements surrounding their use. While these systems are not currently mandated, many newer installations are utilizing variations of these technologies to provide a layered approach to safety and mitigate the probability of a large-scale incident from occurring.

NREL and other U.S. DOE National Laboratories—like Pacific Northwest National Laboratory (PNNL)—participate in code development related to energy storage systems, including NFPA 855, NFPA 800, UL 9540, UL 9540A, and UL 1973. PNNL is chairing the new NFPA 800, *Battery Code*, with NREL and Sandia National Laboratories participating as well. The goal is to take lessons learned from incidents and combine them with DOE National Laboratory research to improve codes and standards for end use applications.

Appendix C. Fuel Cells Analysis

C.1 Fuel Cell Overview

Four fuel cell technologies were selected for initial screening: solid oxide fuel cells (SOFC), molten carbonate fuel cells (MCFC), proton exchange membrane fuel cells (PEMFC), and phosphoric acid fuel cells (PAFC).

Table C-1 provides a comparative overview of operational parameters for the four fuel cell technologies considered.

Table C-1. Comparative Overview of Key Fuel Cell Technologies[a]

Type	Annual Global Manufacturing Capacity [2]	Fuel Type	Start-Up Time	Ramp-up Rate (Once Warm)	Energy Input (Electrical Efficiency) [3]
SOFC	>330 MW	Natural gas, Biogas, Hydrogen	6 hours or more [6]	~3% per second [7]	5,250–7,580 BTU/kWh (45%–65%)
MCFC	<330 MW	Natural gas, Biogas	~6 to 24 hours	~2%–10% per minute (<1% per second)	6,200–7,580 BTU/kWh (45%–55%)
PEMFC	>>330 MW, primarily for mobility	100% pure hydrogen only	Seconds to a few minutes	Almost immediately	5,690–7,580 BTU/kWh (45%–60%)
PAFC	~330 MW [13]	Natural gas, Biogas, Hydrogen	~3 hours [16]	~2% per second [16]	6,200–8,530 BTU/kWh (40%–55%)

[a] Notes:

- The data ranges presented in this table reflect general industry trends and typical performance metrics for fuel cell technologies. These values may vary depending on geographic regions, specific original equipment manufacturer (OEM) designs, and operational conditions.
- Annual global manufacturing capacity is estimated relative to the size of the Scattergood project. If the annual manufacturing capacity is less than 330 MW for a particular fuel cell type, it is not ruled out for Scattergood. Rather, it means the fuel cell type must be manufactured over multiple years.
- Some figures, particularly for startup times, ramp-up rates, capital costs, and efficiencies, are based on industry norms and estimates. While not all data points have direct, verifiable sources, they generally fall within accepted performance ranges for fuel cells.
- Emissions data (CO_2, NO_x, SO_x) are typical outputs based on common fuel types, such as natural gas, biogas, and hydrogen, and may vary due to regional regulations or specific system configurations.
- These figures are representative of current fuel cell technologies but are subject to change as new systems and technological advancements emerge, and they should be interpreted with that context in mind.

Solid Oxide Fuel Cell

SOFCs are a mature technology that was first developed in 1937 and commercialized in the 1960s. In 2024, the major manufacturers include Bloom Energy (1-GW annual manufacturing capacity) [7], [17], Ceres Power (partners Bosch and Doosan, 250-MW annual manufacturing capacity combined [18]), SolydEra, and FuelCell Energy (current 10-MW annual manufacturing capacity, goal ~500 MW) [19]. Given the current landscape of SOFC manufacturing, delivering and installing 330 MW of SOFCs by January 2030 to Scattergood might be achievable. Each manufacturer offers modular solutions, with units of 200–300 kW. Due to the high heat production, additional space will be needed to accommodate heat recovery or other thermal management infrastructure.

SOFCs are efficient, achieving up to 60% electrical efficiency on a lower heating value basis. Available systems on the market offer a wide range of fuel mixture options, including 100% natural gas or biogas, dual-fuel configurations with up to 20% hydrogen (SolydEra), pure hydrogen (Bloom Energy), and seamless fuel blending from 0%–100% hydrogen with natural gas or biogas (FuelCell Energy). Additionally, SOFCs are capable of load-following operations [20] and can ramp at around 3% nameplate capacity per second while in operation.

However, the startup capabilities of SOFCs are more limited compared to PEMFCs, which could affect their suitability for applications requiring rapid response. As listed in Table C-1, SOFC stacks can take several hours to reach operating temperature from a cold start. SOFCs operate at high temperatures (~600–1,000°C). For situations requiring faster responsiveness, SOFCs may be supported by a thermal management system to keep the system warm when there is no electricity demand from the fuel cell plant. This could entail keeping the system operating at a low output when the system would otherwise be turned off due to low electricity demand. The electricity generated during these time periods would either be curtailed or could be sent to the grid at the expense of a different electricity generator in the grid system being ramped down or shut off. In addition to enabling rapid response to changes in electricity demand, keeping the SOFC system in an operating state also can reduce the amount of stack replacements needed over the system lifetime [7]. Maintaining a hot standby or low percent maximum output state through a thermal management system is necessary to reduce startup time.

The average selling price for Bloom Energy SOFCs was $3,363/kW in Q2 2024, with the product cost of $2,360/kW [21]. Prices for other manufacturers have not been published. Currently, there are around 1.2 GW of Bloom Energy SOFCs are in operation across 1,200 locations in seven countries [22]. A primary challenge of using SOFCs for the Scattergood installation is thermal management. Due to the significant heat generated by SOFCs, the installation will require heat-resistant materials as well as additional space and cost considerations for cooling.

Molten Carbonate Fuel Cell

MCFCs were first developed in the 1950s and became commercialized in the late 1990s. In 2024, FuelCell Energy is the sole manufacturer of MCFCs. There is currently no record of hydrogen-only modules or retrofit options available for MCFCs. Given these technical constraints, MCFCs were not considered for further analysis.

Proton Exchange Membrane Fuel Cell

PEMFCs are primarily used in mobility and small-scale backup power applications that require rapid startup and ramping abilities. However, major manufacturers such as Ballard Power and Plug Power have expanded their offerings to include stationary products. Ballard offers fuel cells in increments of 200-kW modules with scalable power up to 1.2 MW, integrated into containers [10]. Plug Power offers fuel cell units with power output in increments of 125 kW with scalable power up to 1 MW as a containerized solution [25]. These fuel cells are versatile, suitable for indoor and outdoor deployment, and can be connected in parallel to achieve multimegawatt power output.

PEMFCs have the highest manufacturing capacity compared to other fuel cell types. Ballard Power, for instance, has the capability to manufacture 3.7 GW fuel cell modules by power output globally, including 0.9 GW distributed between Canada and the United States [26]. Additionally, an integrated Ballard gigawatt-scale fuel cell production facility is planned in Texas and scheduled to start operations in 2027 [27]. Plug Power also has a large manufacturing capacity across multiple locations in the United States [28]. Although these companies manufacture fuel cell modules along with other value chain components (e.g., membrane electrode assemblies, stacks) for both stationary and nonstationary applications, it is worth noting that the installations of stationary PEM fuel cells are currently limited. PEMFCs have been demonstrated on a megawatt scale as backup power source for data centers. Current projects in development include an 8-MW fuel cell system by Plug Power for a microgrid in California and a 3-MW baseload power plant project by Ballard in France [26], [29].

The selling price of PEMFCs could range from $1,300/kW to $7,933/kW. The upper bound is defined based on a recent demonstration of a 1.5-MW PEMFC at a data center with project costs totaling $11.9 million [30]. Note, however, that the project costs include liquid hydrogen storage and vaporizer, which may not be necessary for the Scattergood facility, thus potentially lowering the capital cost on a per-kilowatt basis. The lower bound is defined by NREL's internal analysis, which models a stationary PEMFC installation at the 100-MW scale when utilizing heavy-duty-vehicle PEMFCs currently available from OEMs, inverter medium-voltage transformer units currently available for solar PV installations, and industrial air-cooling units.

PEMFCs function at lower temperatures (~60°C–80°C), allowing for rapid startup and high power density. Unlike other fuel cell types, PEMFCs require pure hydrogen as input fuel and are sensitive to fuel impurities, limiting their flexibility. Literature has suggested that on a small scale, the fuel processing system can be implemented as part of the balance of the plant, allowing natural gas to be reformed into hydrogen before entering the fuel cell stack [31]. However, this approach has not been proven at scale and might contribute substantially to capital costs. Finally, PEMFCs hold an advantage over other fuel cell types in terms of operational flexibility: Quick startup allows them to reach full power in less than 2 minutes from cold start and in less than 30 seconds from standby mode [26]. On-site natural gas reforming might worsen their dynamic performance. However, if on-site hydrogen storage is also included at Scattergood, it can temporally decouple hydrogen synthesis from hydrogen consumption by the fuel cell such that the PEMFC dynamic performance is maintained.

We assume blended hydrogen and natural gas fuel will be delivered to the Scattergood site via an existing pipeline, and the blend will go through the steam methane reformer (SMR) to produce pure hydrogen suitable for PEMFCs. The hydrogen can then be sent directly to the PEMFCs or compressed into 350-bar hydrogen storage. When the SMR is turned off or warming up, hydrogen in storage can be decompressed and piped to the fuel cell system across Grand Avenue, which takes in hydrogen at much lower inlet pressure (e.g., 5–8 bar) [59]. In 2035, the PEMFCs can potentially operate without the SMR and on-site storage, given that 99.99% pure hydrogen fuel is available via pipeline.

Phosphoric Acid Fuel Cell

PAFCs are a mature technology originally commercialized in the 1960s. In 2024, the major manufacturers of PAFCs included Doosan Fuel Cell and Fuji Electric. Doosan and Fuji Electric's fuel cell systems are modular, with each unit capable of producing around 100 to 500 kW [15], [32]. In the context of Scattergood, which requires 330 MW of electricity generation capacity, these modular fuel cell systems would need to be stacked together. To date, the largest installation of pure hydrogen PAFC fuel cells for stationary power applications is in Seosan, South Korea, where 114 units, each with a capacity of 460 kW and manufactured by Doosan, are combined to achieve a total power of roughly 50 MW. Doosan has a PAFC manufacturing capacity of over 100 MW per year in South Korea and an additional 73 MW per year in the United States under their subsidiary HyAxiom. While it would be impossible for Doosan to produce 330 MW of PAFCs for Scattergood in one year, with advanced notice and planning, it might be possible for them to produce and install 330 MW of PAFCs by the start of 2030 [14].

PAFCs use liquid phosphoric acid as an electrolyte and porous carbon electrodes with a platinum catalyst coating. The capital costs for PAFCs are comparable to SOFCs, with the platinum-based catalyst being one of the primary cost drivers [1]. In terms of fuel input, PAFCs can operate either on natural gas, biogas, or hydrogen. Doosan's PureCell Model 400 operates on natural gas, but it can handle up to 30% by volume hydrogen. This PAFC technology could be used between 2030 and 2034 when Scattergood operates on a 30% H_2/70% natural gas blend. Once Scattergood switches to 100% green hydrogen, the reformer can be removed from the PureCell Model 400 such that it operates according to the PureCell Model 400 hydrogen specifications, which require a fuel supply of 93% hydrogen or greater [15]. The most notable demonstration of hydrogen PAFCs is a 50-MW PAFC power plant in South Korea. This power plant is built in a city block shape with three vertical stories of fuel stacks, with an additional fourth story for cooling on top of each block [14].

One of the primary challenges of using PAFCs at Scattergood is the technology's slow startup times. PAFCs operating at moderate temperatures (~150°C–200°C) and can take 3 hours to reach an operating state from a cold start. However, once in operation, they can provide rapid response with a ramping rate of about 2% nameplate capacity per second [16]. PAFCs are best equipped to operate continuously, such that when the electricity generation is not needed at Scattergood, the PAFCs would remain operating at a low output to remain warm and maintain rapid response capabilities. During these periods, the electricity generated from the PAFCs would either be curtailed or could be sent to the grid at the expense of another electricity generator on the grid being ramped down or shut off. In addition to enabling rapid response to changes in electricity demand, keeping the PAFC system in an operating state can also reduce the amount of stack replacements needed over the system lifetime [16]. Manufacturer data indicate that as few as 50 start/stop cycles would require replacement of the fuel stack. This is largely incompatible with the type of flexible operation needed in a system responding to an increasingly variable supply of electricity, and PAFC was not analyzed in detail for this analysis.

C.2 Footprint Assessment

All products considered in this footprint assessment are containerized solutions. As such, we assume that basic electrical infrastructure is integrated in the container, and that fuel cells can be swapped out individually as they reach the end of their lifespan while the container remains in place. If these assumptions are met, a modular design of the plant is possible.

The containerized solutions considered in this analysis have maintenance access on one side of the units. To minimize space while maintaining easy access for maintenance, we propose to arrange the units in rows of back-to-back units with sufficient space for maintenance access with a forklift (7 m) between each pair of rows. This is illustrated in Figure C-1 (left).

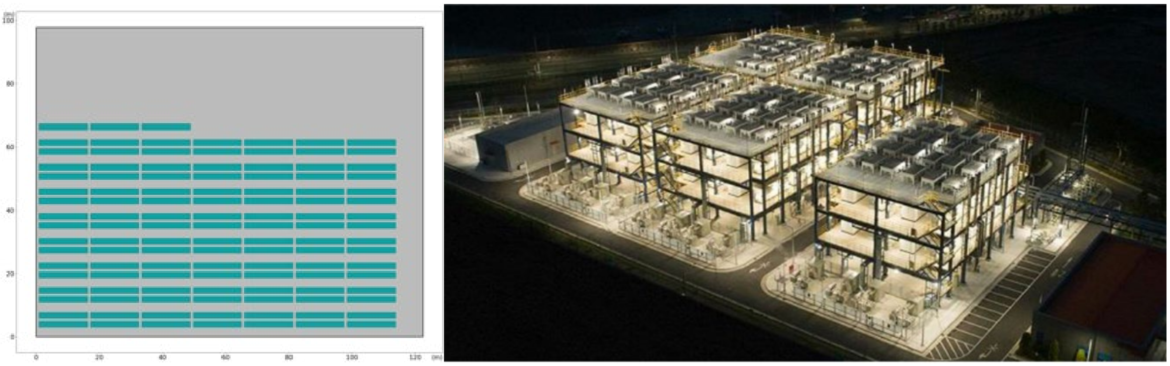

Figure C-1. Example of fuel cell layout in back-to-back rows (left). Example of a stacked layout in a city block type configuration (right).

Image credit: HyAxiom. PureCell Model 400: A versatile product line enabling transition [35]

We keep sufficient spacing on all sides of the unit to ensure air flow and compliance with safety requirements. We assume a minimum of 1 m between units on each side (largest safety spacing requirement found in manufacturer requirements) unless a product has been confirmed to require less safety buffer by its manufacturer. We further assume that units can be arranged vertically (stacked) using a steel structure or similar. This has been done for the HyAxiom demonstration in South Korea, as shown in Figure C-1 (right). The installation has three levels of fuel cell containers with an additional level of cooling on top, all stored on steel beam structures. Safety margins dictate the height of each level in such a scenario. The additional footprint increase for the racks should be minimal, but it could be integrated with the spacing requirements between containers.

Cooling and Thermal Management

SOFCs are typically cooled using air exchange [36], so additional infrastructure does not need to be accounted for.

For this analysis, we assume PEMFCs can use liquid cooling [37]. Under the assumption that cooling takes up less space than the fuel cells themselves, it could be placed on top of the containers. If the container itself cannot bear the load of a cooling system, a frame of steel beams could be constructed, similar to what was done for the plant in Figure C-1 (right).

Footprint Analysis for PEMFCs

All available PEMFCs operate on pure hydrogen. Therefore, the initial solution for 2030 will require reformers to generate hydrogen. The reformers have an expected startup time of 3 hours [34]. To compensate for this delay, sufficient hydrogen storage for 3 hours of operation is added such that the fast startup times of PEMFCs can be leveraged even when the reformer is warming up. We assume fuel cells will be placed in the area reserved for SMP, with additional infrastructure for hydrogen storage and steam methane reformers in the southern plot, as shown in Figure C-2.

Figure C-2. Assumed configuration of PEM fuel cells.

Original image credit: LADWP. Draft Environmental Impact Report: Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project [33]

We compare products from four different manufacturers of PEMFCs: Ballard, SinoHytec, Plug Power, and Toshiba.

Ballard has numerous models available. The FCwave model [10] is advertised for stationary installations and is therefore the best candidate for this plant. Each unit has a capacity of 200 kW, so a total of 1,650 units are needed to produce 330 MW. Due to its very compact size of 4 ft x 2 ft 6 in. x 7 ft 3 in., the units fit in just 1.69 acres and do not have to be stacked. This leaves a significant portion of the dedicated space available for other uses, such as hydrogen storage, as seen in Figure C-3 (top left).

The SinoHytec model [12] has a much larger size of 50 ft x 6 ft x 8 ft. However, at 3 MW per unit, only 110 units are needed to produce 330 MW, so its overall footprint of 1.84 acres would still fit well within the bounds of the dedicated fuel cell space without stacking, as seen in Figure C-3 (top right).

Plug Power’s model [25] has a size of 40 ft x 8 ft x 19 ft. At 1 MW per unit, 330 units are needed to produce 330 MW. In a flat arrangement, the installation would require 4.88 acres. The footprint can be reduced to 1.68 acres by stacking the units in a structure with 3 levels, at a medium height of 19.4 m (or about 64 ft), which is likely at the upper end of the feasible range.

As seen in Figure C-3 (bottom left), this stacked layout would require about 1.69 acres and leave a similar amount of space as the SinoHytec product.

Toshiba's model [38] is relatively small at about 9 ft 2 in. x 6 ft 8 in. x 6 ft 3 in.; however, each unit produces only 100 kW, so a total of 3,300 units are needed to produce 330 MW. In a flat arrangement, this would require a footprint of 11.41 acres. To fit these fuel cells in the available area would require a structure that is six levels tall. Due to the much shorter height of the units, this structure would be shorter than the one for Plug Power, at about 16.4 m (or about 54 ft), and it would take up almost the entire available space at 2.25 acres.

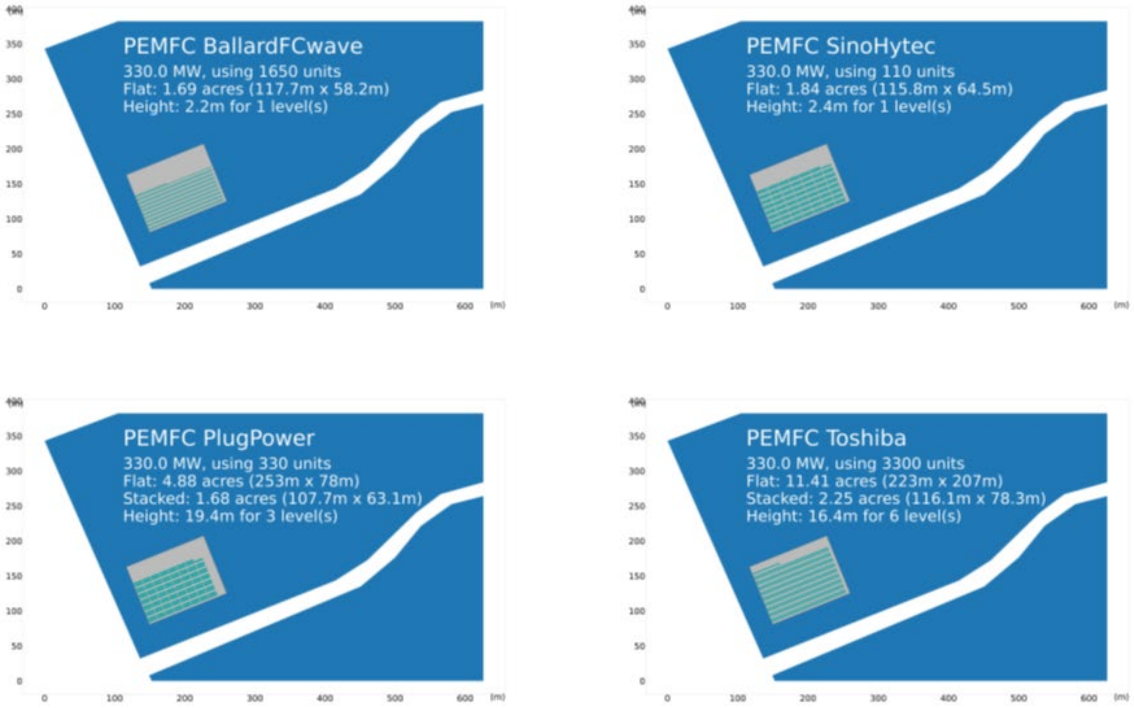

Figure C-3. Footprint analysis for PEMFC

Footprint Analysis for Steam Methane Reformers

PEMFCs require pure hydrogen input; therefore, reformers are needed to convert available natural gas to hydrogen. To size the SMRs, we assume an average fuel cell efficiency of 50% lower heating value, and reformers are at 70% efficiency [39]. SMR systems typically need about 20–30 m^2/MW (including all required infrastructure and safety buffers), where MW refers to the power rating of the hydrogen gas. This results in the footprint for the required capacity of between 4.66 and 6.99 acres.

This would limit the possible PEMFCs to the Ballard or SinoHytec products, which both have small enough footprints to leave some space for hydrogen storage next to the fuel cells as shown in Figure C-4 (left).

An SMR plant at the lower range of 4.66 acres would leave sufficient space for energy storage alongside the SMR on the southern plot. An SMR plant that is above midsize would not fit on the southern plot.

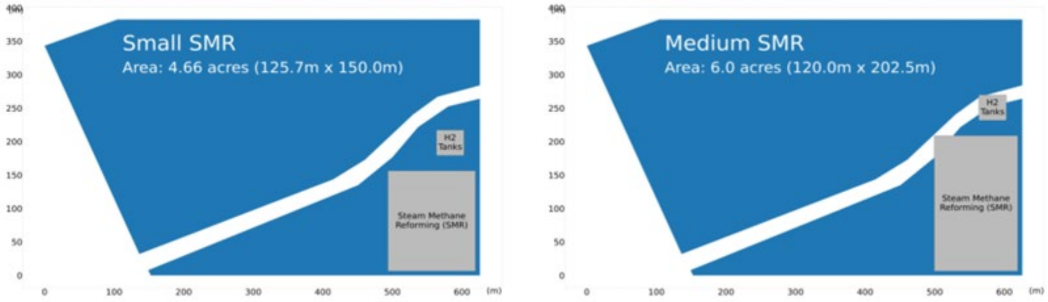

Figure C-4. Footprint analysis of SMR

Footprint Analysis for Hydrogen Storage

We assume 3 hours of hydrogen storage to allow time for the reformers to start. This requires about 60,000 kg, or about 2,609 m^3 of storage. Using 100-m^3 tanks, this would require 27 tanks. Each tank is assumed to be 10–12 m long and has a diameter of 3–4 m. Following the spacing requirement between tanks, the footprint for hydrogen storage would be between 0.48 acres and 0.76 acres when laid out in a single level without stacking. When stacking them two levels high, they can fit in 0.29 to 0.35 acres, as shown in Figure C-5. Access to the tanks is at one short end of each tank, so the best arrangement for them is with tanks parallel to each other as illustrated.

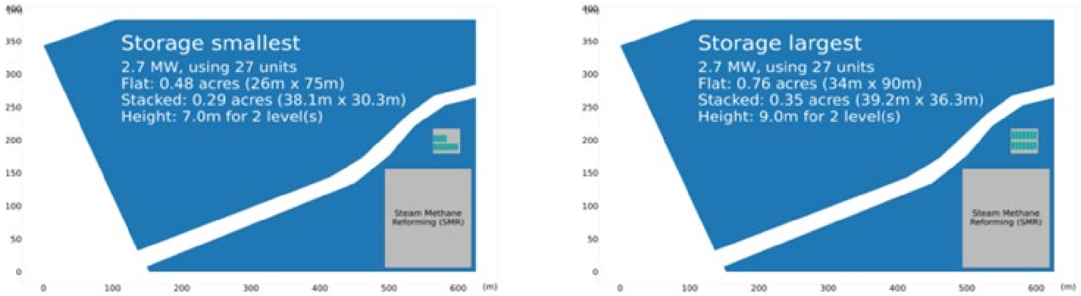

Figure C-5. Footprint for hydrogen storage

The space around gaseous hydrogen tanks is determined based on NFPA2 Tables 7.3.2.3.1.2 (B)(a-c), which define setback distances for bulk outdoor gaseous hydrogen storage [40]. At 350 bar (about 5,077 psi), the proposed storage falls in the range of 3,000–7,500 psi. For this range, NFPA2 typically requires 13-ft distance from Exposure Group 1 (e.g., lot lines) and 10-ft distance from Exposure Groups 2 (exposed people and parked cars) and 3 (e.g., buildings, flammable gas storage, and encroachment by overhead utilities[36]). However, these setback distances are based on a 0.28-in.-diameter inlet pipe to the storage tanks, where the inner diameter of the inlet pipe determines the maximum flow rate of hydrogen into the storage tanks. The maximum internal diameter piping listed in Table 7.3.2.3.1.2(B)(c) is 2 in., which might be more applicable for the hydrogen flow rates anticipated at Scattergood with fuel cell

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[36] It should be noted that encroachment by overhead utilities is defined as “horizontal distance from the vertical plane below the nearest overhead electrical wire of building service,” i.e., there must not be overhead utilities crossing into the 10-ft perimeter around the storage pad.

installations. With 2-in. inner diameter piping, setback distances of 171 ft for Exposure Group 1, 107 ft for Exposure Group 2, and 75 ft for Exposure Group 3 are required from the bulk gaseous storage system. As shown in Figure C-5, the maximum possible distance of the hydrogen storage pad to the lot lines and SMR is about 70–75 ft, which would mean the storage system could not fit in the area indicated in Figure C-5. However, setback distances for Exposure Groups 1 and 2 can be reduce to 0 ft if a fire barrier wall with a fire resistance rating of at least 2 hours is built to enclose the storage system [40]. With the fire barrier wall installed, a storage system with 2-in.-diameter piping may fit in the allotted space shown in Figure C-5 while meeting required safety codes in NFPA2.

Footprint Analysis for SOFCs

We compare three products from two different manufacturers. Bloom Energy produces a few different products. We consider one hydrogen model and one natural gas model, as the other products are identical in functionality, but they have less suitable shapes. The hydrogen model operates with pure hydrogen, whereas the natural gas model can function on natural gas, biogas, or blended hydrogen, and the cells within the model can be replaced with pure hydrogen cells at a future date.

The Bloom Energy hydrogen model [4] produces 300 kW per unit, and 1100 units would be needed to produce 330 MW. The hydrogen model is available in two configurations. The more space-saving unit size of 17 ft 11 in. x 8 ft 8 in. x 6 ft 9 in. means that the installation would take up 7.84 acres in a flat arrangement, but fit on 2.27 acres using a short four-level structure of 11.2 m (about 37 ft) height, as shown in Figure C-6 (left). At the given height, this product could be a feasible solution for the Scattergood installation.

The Bloom Energy natural gas model [17] needs 1,016 units at 325 kW per unit. The unit size of 29 ft 5 in. x 4 ft 4 in. x 8 ft 2 in. means that the installation would take up 7.32 acres in a flat arrangement. It would fit on 2.24 acres using a short four-level structure that is slightly taller than that for the hydrogen model at about 13 m (about 43 ft, as shown in Figure C-6 (middle)). At the given height, this product could be a feasible solution for the Scattergood installation, and the option of replacing the natural gas cells with hydrogen blend or pure hydrogen fuel cells could make it an attractive choice.

FuelCell Energy's model [5] produces 250 kW per unit, so one would need 1,610 units to produce 330 MW. With a unit size of 35 ft 3 in. x 8 ft 3 in. x 10 ft 6 in., it would fill almost the entire available land (20.3 acres) when arranged flat. To make it fit into the available space would require an extremely tall 10-level structure of 41 m (about 135 ft) and 2.26 acres (see Figure C-6 (right), which makes this product unsuitable for the Scattergood installation.

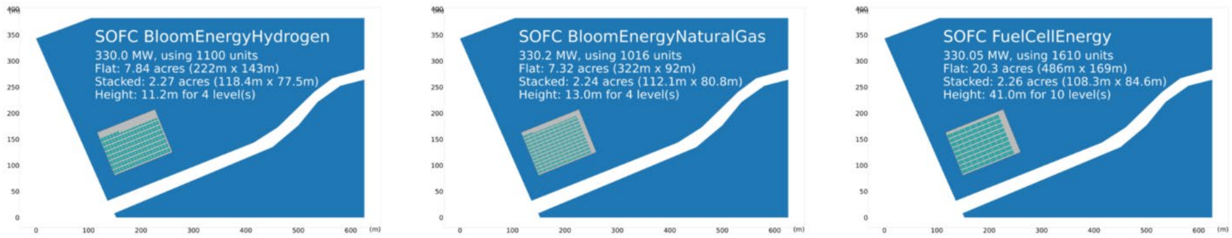

Figure C-6. Footprint of SOFC

C.3 Capital and Fixed Costs

Table C-2 details the key parameters used for capital and other fixed costs.

Internal NREL analysis estimated the PEMFC installed capital cost on a 100-MW scale when utilizing currently available heavy-duty-vehicle PEMFCs, inverter medium-voltage transformer units currently available for solar, and industrial air coolers. The analysis estimates the current installed cost of $1,300/kW for PEMFCs; however, for this project, we apply another 50% to the cost to account for higher labor costs for the Southern California market, the uncertainty of the fuel cell module price, and the maximum process and project contingencies associated with a first-of-a-kind installation. The SOFC installed capital cost is based on the manufacturer reported average selling price of their product per kilowatt as of Q2 2024 and a 0.2 installation factor [21].

The PEMFC scenario will require an external steam methane reformer and on-site hydrogen storage. The installed capital cost of the SMR is based on the H2ALite model [55]. On-site hydrogen storage is sized for 3 hours of plant operation at full capacity to compensate for steam methane reformer startup times, thus maintaining the flexibility of the PEMFCs. Storage cost should be treated as an upper bound estimate, as it is based on the cost of a 600-kg Type I tank and a 0.25 installation factor, while the hundredfold storage capacity increase at Scattergood would achieve considerable economies of scale. PEMFC fixed operating costs are based on NREL's techno-economic modeling of a 1.5-MW installation, and the SMR fixed operating costs are extracted from the H2ALite model. Finally, for SOFC, higher fixed operating costs are assumed based on the higher operating temperatures of the fuel cells.

Table C-2. Assumed Capital and Fixed Costs and Financial Parameters by Fuel Cell Type

Application	PEMFC	SOFC
Average lifetime electrical efficiency, (higher heating value)	45%	46%
Installed fuel cell and balance of plant capital cost, $/kW	1,560–2,340	3,044–4,566
Installed steam methane reformer cost, $/kW	1,361	n/a
Installed hydrogen storage cost, $/kW	193[a]	n/a
Fixed operational expenses, $/kW-yr	67–184[b]	110–165

[a] Includes hydrogen compression up to 350 bar.

[b] Lower bound with SMR (2030–2034), upper bound without SMR (2035–2059). Note that all values used are considerably higher than EIA estimates of about $40/kW-yr.[37]

Incentives

Until recently, fuel cell technology qualified for the investment tax credit (§ 48) irrespective of the fuel it used [60]. Starting in January 2025, the credit was replaced by a new tech-neutral credit, § 48E Clean Electricity Production Investment Credit. Previously, a qualifying fuel cell facility (electrical efficiency > 30%, nameplate capacity > 0.5 kW) could get a credit of up to 30% contingent on meeting the labor standards. Additionally, a project could qualify for two bonus incentives: an energy community bonus of up to 10%, applicable to regions like Los Angeles, and a domestic content bonus of up to 10%, determined by the origin of fuel cell manufacturing [61].

However, a requirement for a qualifying facility to have zero net greenhouse gas rate, considering the whole life cycle of the project, was imposed in the final rule from the Internal Revenue Service in January 2025 [61]. For example, if the fuel cell uses hydrogen produced through combustion or gasification (e.g., SMR) or natural gas is the system-level fuel input for the fuel cell (e.g., SOFC with the internal methane reforming), the system would not be eligible for the investment tax credit. On the contrary, if a fuel cell operates on hydrogen produced through electrolysis, the facility is eligible for the credit.

Consequently, the potential fuel cell facility at Scattergood will not qualify for the investment tax credit irrespective of the fuel cell type installed because the fuel delivered to Scattergood in 2030–2034 would primarily be natural gas. Note that in 2035, there is a possibility to repower the whole system, given that electrolytic hydrogen is available; however, that is outside the scope of the analysis, as the current investment tax credit will start phasing out following in 2032 or the calendar year in which the greenhouse gas emissions from the production of electricity in the United States are equal to or less than 25% compared to calendar year 2022.

C.4 Operating Costs Including Stack Replacement

Table C-3 describes the operational parameters assumed for fuel cells. The average lifetime electrical efficiency on a higher heating value basis for SOFCs are reported by OEMs [17], [35] ,

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[37] EIA (S&L)

while the PEMFCs efficiency is based on the average between projected 2023 beginning-of-life and end-of-life efficiency of a heavy-duty PEMFC at rated power conditions [51].

Table C-3. Operation-Related Values for Fuel Cells

Line	PEMFC	SOFC [7]
Variable O&M	\$2.3/MWh[38]	\$0.60/MWh
Heat rate (BTU/kWh - natural gas)	10,943	7,421
Heat rate (BTU/kWh - pure H_2)	7,595	7,421
Start time	<1 hour	>6 hours [6]
Minimum output	5%	30%
Ramp rate	>100%/minute	100%/minute (when operating at temperature)
Stack life (constant operation)	Up to 25,000 hours (lifetime depends on operating schedule). Due to extensive cycling required as an SMP alternative, stack life restricted to 6,000 hours before replacement	5 years with constant operation (44,000 hours)
Stack life (with on/off cycles)		2 years with 1 start per week
Start fuel	0	0

PEMFCs offer rapid response capabilities directly from a cold start. The primary challenge with deploying PEMFCs at the project onset in 2030 is that PEMFCs can only operate on pure hydrogen, and the facility will be fed with a natural gas/hydrogen mix (30% H_2 content by volume). This necessitates the installation of a reformer to convert the natural gas feedstock into hydrogen at a purity required for PEMFCs (>99.9% H_2). In addition to the reformer, hydrogen storage is also recommended such that hydrogen production via the reformer and hydrogen consumption by the PEMFCs can be decoupled. Without storage, the ability of the PEMFCs to meet electricity demands would be constrained by the operating characteristics of the reformer. Conventional SMRs typically operate near capacity and are only shut off for planned maintenance. This is primarily due to the cost savings of operating near full capacity but also because of the long startup times (several hours) for reformers. Once the feedstock is converted to pure hydrogen, the reformer will no longer be necessary. The hydrogen storage may still be used for reliability purposes.

Hydrogen cost is assumed based on the national and global targets; however, we assume upper-bound estimates for the Southern California market. [56], [57]. We assume all fuel (natural gas or hydrogen) is delivered to Scattergood via pipeline, and this analysis assumes that the

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[38] \$1.46/MWh for the reformer plus \$0.59/MWh for the fuel cell (later adjusted to \$2022 from EIA), then both multiplied by 1.08

hydrogen value chain (e.g., pipeline upgrades) is accounted for in the delivered price of fuel. The study employs the H2FAST model [49] developed by NREL to evaluate each fuel cell type.

High-temperature SOFCs are designed to provide continuous power generation. When planned utilization is lower, there can be two simplified operating strategies. First, keep the fuel cell operational at a minimum 30% of the nameplate capacity. This scenario is preferred when the operating profile of the plant is continuous, even at a minimum level, and the electricity generated is sold without curtailment. For the second strategy, if turn-on/off operations are required, the system will necessitate a more frequent stack replacement, as each thermal cycle increases the stack degradation. A transition from a natural gas/hydrogen mix to pure hydrogen will require maintenance to accommodate the new feedstock.

Stack replacement values for PEMFCs represent 44% of the original stack module cost, as platinum recovered from the refurbished stack could offset a portion of the costs associated with refurbishment. For SOFCs, stack replacement value is assumed based on the median average cost of manufacturing for a 250-kW system across manufacturing volumes with an additional 30% markup applied [31].

Stack replacement frequency for PEMFCs is considered irrespective of the actual utilization, and the replacement takes place once the number of operating hours exceeds the stack life. This estimate is based on the most recent announcements from OEMs and should be treated as an upper-bound estimate since there have been no large-scale stationary PEMFC installations to date, and stack degradation is not fully understood [52], [53]. On the other hand, stack replacement frequency for SOFCs and PAFCs is well-documented [35], [54]; however, fuel cell systems designed for continuous operation can only achieve these lifespans when following strict shut-off and maintenance schedules.

Assumption for stack replacements are provided in Table C-4. Of note is the requirement that each on/off cycle for SOFC is assumed to degrade the stack by 0.67%.

Table C-4. Assumed Stack Replacement Schedule and Costs

	Cost ($/kW) ($2022)	
Cost Category	**PEM**	**SOFC**
Replacement interval	6 years	5 years
Replacement cost ($/kW)	$324	$563
Total net present value multiplier assuming 5.5% discount rate	1.8	2.1
Net present value of total cost	$278/kW	$1,167/kW
Additional stack replacements	Operation restricted to 6,000 hours over the 6-year period	Cost equal to 1/150th of the cost of the stack added per start/stop cycle

C.5 Environmental Impact and Safety Assessment

Figure C-7 depicts the emission sources both at Scattergood and upstream of Scattergood for each fuel cell option. Figure C-7(a) shows the emission sources when operating on natural gas/H_2 blends while Figure C-7(b) shows the emissions sources once the gas feedstock to the facility is transitioned to pure hydrogen. In Table C-5, the fuel cell facility emissions results are compared to the actual 2023 emissions rate of the current Scattergood electricity generating facility, a natural gas combined cycle power plant. Notably, Table C-5 only shows CO_2 and NO_x emissions that are or would be created at the Scattergood facility. No emissions generated upstream of the Scattergood facility are presented in Table C-5.

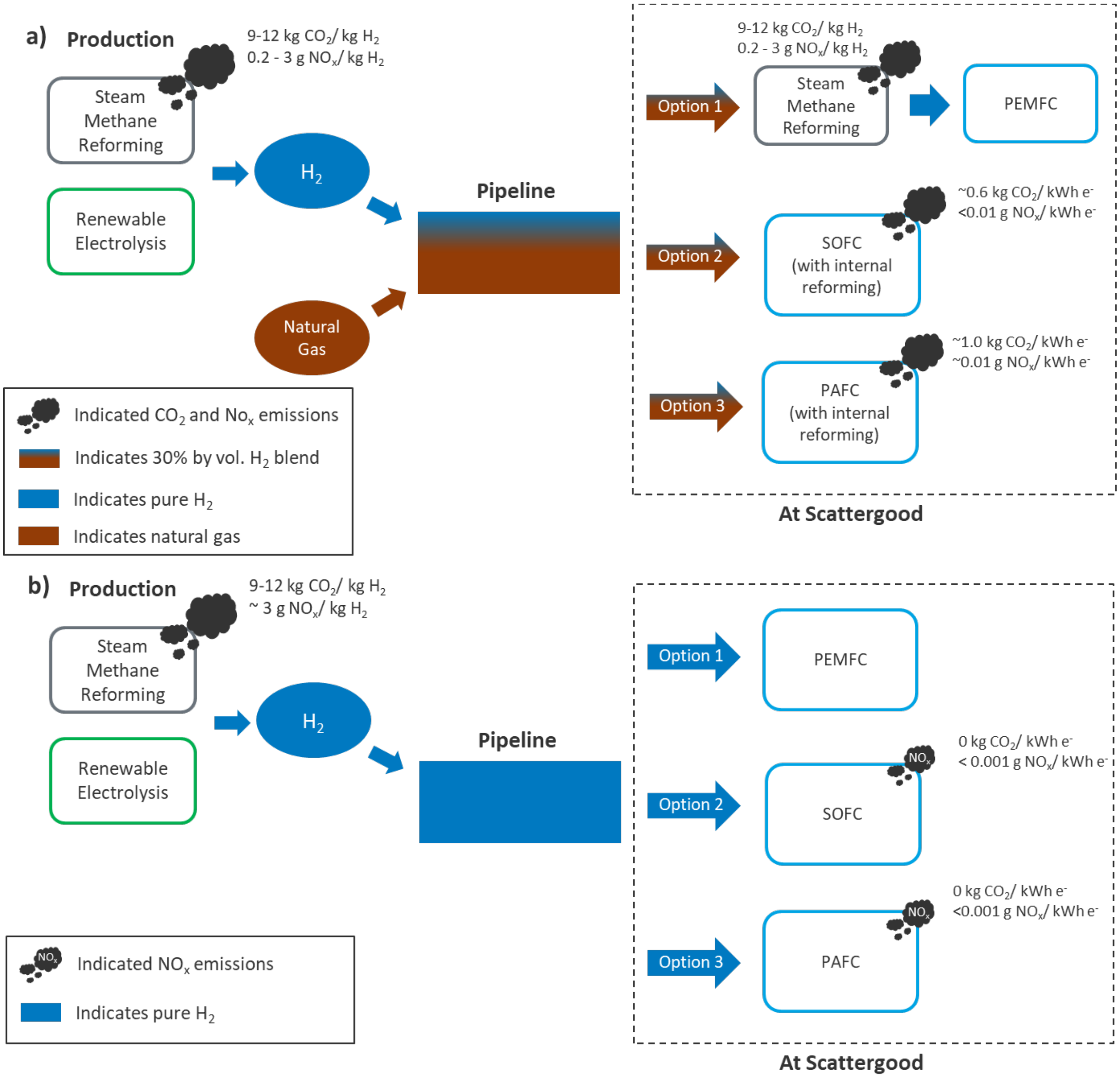

Figure C-7. CO_2 and NO_x emission sources at Scattergood and upstream of Scattergood with fuel cell installation a) between 2030 and 2034 and b) in 2035 and thereafter.

Table C-5. Emissions Rate Comparison

	Fuel Type	
Fuel Cell Type	**30% by vol. H_2 Blend**	**Pure H_2**
PEMFC	0.38–0.61 kg CO_2/kWh e^- 0.009–0.16 g NO_x/kWh e^-	0 kg CO_2/kWh e^- 0 g NO_x/kWh e^-
SOFC	0.56–0.67 kg CO_2/kWh e^- 0.005–0.008 g NO_x/kWh e^-	0 kg CO_2/kWh e^- < 0.001 g NO_x/kWh e^-
2023 Scattergood Natural Gas Combined Cycle Plant (all units)	0.42 kg CO_2/kWh e^- 0.021–0.26 g NO_x/kWh e^-	

Table C-6 shows the assumed emissions rate from fuel cells.

Table C-6. Emissions Analysis Assumptions

Parameters	Value	Units	Sources/Comments
SMR CO_2 Rate	9 to 12	kg CO_2/kg H_2	[63], [64], [65]
SMR NO_x Rate	10 to 150	ppm NO_x	[63], [65]
SMR Exhaust Gas Volume	10	m^3/kg H_2	Based on reaction stoichiometry and GREET assumptions [63]
H_2 Fuel Cell Gas Flow Rate	3 to 6	m^3/kg fuel	Based on reaction stoichiometry with practical adjustments
H_2 Fuel Cell Gas Flow Rate	7 to 10	m^3/kg fuel	Based on reaction stoichiometry with practical adjustments
H_2 PEMFC CO_2 Rate	0	kg CO_2/kWh H_2	N/A. No carbon in reaction.
Natural Gas SOFC CO_2 Rate	0.378	kg CO_2/kWh natural gas	[17]
H_2 SOFC CO_2 Rate	0	kg CO_2/kWh H_2	N/A. No carbon in reaction.
H_2 PEMFC NO_x Rate	0	ppm NO_x	N/A. Low-temperature reaction.
Natural Gas SOFC NO_x Rate	3	ppm NO_x	Conservative estimate based on datasheets [17]
H_2 SOFC NO_x Rate	1	ppm NO_x	Conservative estimate based on datasheets [17]
PEMFC Electrical Efficiency	0.5 to 0.6	kWh e^-/kWh fuel	[3]
SOFC Electrical Efficiency	0.5 to 0.6	kWh e^-/kWh fuel	[3], [17]

In addition to considering CO_2 and NO_x emissions, it is also important to consider the possibility of hydrogen leakage and unintentional hydrogen ignition when constructing a large-scale stationary fuel cell facility. A fuel cell facility must adhere to the safety codes and standards detailed in the National Fire Protection Association (NFPA) Hydrogen Technologies Code, called NFPA2 [40], and the American Society of Mechanical Engineers Standard on Hydrogen Piping and Pipelines, called ASME B31.12 [62]. In NFPA2, required setback distances from hydrogen storage, generation, and end-use infrastructure are listed. In addition, NFPA2 describes the type of protection features necessary for hydrogen equipment enclosures.

Typically, the largest setback distances at a facility handling hydrogen are for hydrogen storage. In the case of the Scattergood facility, which would utilize 3-hour gaseous hydrogen storage of roughly 60,000 kg at 350 bar, setback distances reported in Table 7.3.2.3.1.2(B)(c) should be utilized. Setback distances are greatest for Exposure Group 1, which consists of lot lines, air intakes, building openings, and ignition sources. The other exposure groups are listed in Table 7.3.2.3.1.2(B)(a) of NFPA 2. Depending on the diameter of the pipe feeding hydrogen to the storage tanks, the setback distance from the bulk H_2 storage system at Scattergood could reach as high as 52.1 m (171 ft) in all directions for Exposure Group 1. This assumes a pipe with 2-in. internal diameter connecting each hydrogen storage tank. However, any setback distance for Exposure Groups 1 and 2 can be reduced to 0 m (0 ft) if a firewall is placed around the H_2 storage system. See NFPA2 [40] for more details.

Table 7.1.23.9.1 in NFPA2 lists fire protection features required for different hydrogen infrastructure that may be installed at Scattergood. For gaseous storage, natural or mechanical ventilation systems must be employed, and the storage enclosure must be grounded with explosion control. In addition, the storage enclosure must have detection equipment for gaseous hydrogen leakage and loss of ventilation. For compressors, fuel cells, and SMRs that may be installed at Scattergood, protection features that must be installed include automatic isolation from H_2 storage, mechanical ventilation, storage compartment separation, equipment grounding, explosion control, and gaseous hydrogen leakage, fire, and loss of ventilation detection equipment. For more detail on required safety measures to consider when building a large-scale fuel cell plant, refer to NFPA2 directly [40].

C.6 Supply Chain

This section details the supply chain landscape and operational characteristics of PEMFCs, SOFCs, and PAFCs. Table C-7 provides a summary of the findings regarding the supply chain landscape of each of the fuel cell types.

Table C-7. Fuel Cell Supply Chain Summary

Fuel Cell Type	Major OEMs	Largest Stationary Storage Installation	Global Installed Capacity [41]	DOE Critical Materials (Medium Term) [2], [42], [43]	OEM Supply Chain Concerns
PEMFC	Ballard Power, Plug Power	15 MW, planned (Ballard Power) [44]	~300 MW >1.0 GW including mobility	Platinum Graphite Nickel	None Reported
SOFC	Bloom Energy, Ceres Power	10 MW, operating (Bloom Energy) [45] 80 MW, planned (Bloom Energy) [46]	>1.0 GW	Cobalt Nickel	None Reported [7]

Major OEMs from which LADWP can look to source PEMFCs include Ballard Power and Plug Power. The majority of installed PEMFC capacity in 2024 is for mobility applications such as fuel cell electric vehicles and buses. As of 2024, around 300 MW of PEMFCs have been deployed globally for stationary applications [41]. After correspondence with OEMs, it was determined that there would be minimal concerns with supplying 330 MW of PEMFCs to Scattergood by 2029 as annual manufacturing capacity for PEMFCs exceeds 1 GW. Ballard Power has more than 1 GW of annual manufacturing itself [48]. However, the largest planned installation of PEMFCs for stationary applications is a 15-MW installation by a company based in the United Kingdom [44]. This is significantly smaller than the potential installation at Scattergood and may make a PEMFC system at Scattergood the first of its size. While a 330-MW PEMFC is feasible by 2029, the size of the facility may present challenges not realized by smaller-scale stationary PEMFC facilities in operation in 2024.

Major OEMs from which LADWP can look to source SOFCs include Bloom Energy and Ceres Power. As of 2024, one of the largest SOFCs installations for stationary applications is a 10-MW facility in Colchester, Connecticut, by Bloom Energy [45]. Bloom Energy also has plans to delivery 80 MW of SOFCs to South Korea for a project that is set to begin operations in 2025 [46]. While 80 MW is still more than 75% smaller than the potential Scattergood installation, learnings from the 80-MW installation in South Korea may be valuable for a potential future installation of SOFCs at Scattergood. After correspondence with OEMs, it was determined that there would be minimal concerns with supplying 330 MW of SOFCs to Scattergood by 2029 as annual manufacturing capacity for SOFCs exceeds 1 GW. Bloom Energy has more than 1 GW of annual manufacturing capacity by itself [7]. OEMs also confirmed that there should not be any supply concerns for materials or subcomponents that are used in the assembly of SOFCs.

While OEMs for each fuel cell technology have noted supplying 330 MW of PEMFCs should not be a concern by 2029, it is worth noting that each fuel cell type analyzed contains critical materials for energy, as defined by the U.S. Department of Energy (DOE) [42]. In the medium term (2025–2035), materials such as platinum, graphite, nickel, cobalt, and silicon carbide are each viewed as critical, meaning that they have a high importance to energy and have a high supply risk. Of these materials, platinum, graphite, and nickel are found within PEMFCs, cobalt and nickel are found within SOFCs, and platinum, graphite, and silicon carbide are found within PAFCs [2], [43]. Table C-8 lists what components each of these materials are found in. While not labeled as a critical material, perfluorosulfonic acid (PFSA) is another material used in PEMFC membranes that may also face future supply risk due to environmental and health issues caused by the substance. Many governments have moved to ban PFSA and other per- and polyfluoroalkyl substances (PFAS) from manufactured products [2].

It is important to note that some of these critical materials may face challenges such as geopolitical tensions, trade restrictions, and fluctuations in global demand causing dramatic price changes. It is therefore imperative for LADWP and the selected fuel cell supplier to continuously monitor the supply chain for the selected fuel cell type and develop contingency plans to mitigate these risks.

Table C-8. Fuel Cell Components Containing Critical Materials [2], [43]

Fuel Cell Type	DOE Critical Materials for Energy (Medium Term)	Components Containing Material
PEMFC	Platinum	Electrode catalyst
	Graphite	Catalyst support, gas diffusion layer, bipolar plates
	Nickel	Gas diffusion layer, bipolar plates, end plates
SOFC	Cobalt	Solid air electrode
	Nickel	Solid fuel electrode

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