Cost Analysis of Heavy-Duty Vehicle Proton Exchange Membrane Fuel Cell Stationary Power Plants

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The National Laboratory of the Rockies is a national laboratory of the U.S. Department of Energy, Office of Critical Minerals and Energy Innovation, operated under Contract No. DE-AC36-08GO28308.

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Technical Report
NLR/TP-5400-91146
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NATIONAL LABORATORY OF THE ROCKIES

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Suggested Citation
Reznicek, Evan, Andreas Berres, Yijin Li, Vignesh Ramasamy, Michael Penev, Mark Chung, and Samuel F. Baldwin. 2026. *Cost Analysis of Heavy-Duty Vehicle Proton Exchange Membrane Fuel Cell Stationary Power Plants*. Golden, CO: National Laboratory of the Rockies. NLR/TP-5400-91146. https://www.nlr.gov/docs/fy26osti/91146.pdf.

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Acknowledgments

The authors would like to acknowledge the input and support received from the following individuals in reviewing this report:

- Joe Brauch, Jeffrey Mohr, and Mark Ruth (NLR)
- Sandy Cai (Ballard)
- Karen SwiderLyons (Plug Power).

List of Acronyms

AC	alternating current
ASME	American Society of Mechanical Engineers
BOP	balance of plant
DC	direct current
EIA	U.S. Energy Information Administration
EPC	engineering, procurement, and construction
FCB	fuel cell building
IR-UV	infrared-ultraviolet
kW	kilowatt
MVT	medium-voltage transformer
MW	megawatt
NETL	National Energy Technology Laboratory
NGCT	Natural Gas Combustion Turbine
NGCC	Natural Gas Combined Cycle
NLR	National Laboratory of the Rockies
PEM	proton exchange membrane
PV	photovoltaic
VDC	voltage DC

Executive Summary

The U.S. electricity demand is expected to grow substantially in the coming years (National Electrical Manufacturers Association 2025). Hydrogen-fueled proton exchange membrane (PEM) fuel cells could be an effective technology for meeting an important part of the resulting peak demands because of their rapid startup and response times, their potential for cost reductions, and the many different energy sources that can be used to produce the hydrogen that fuels PEM fuel cells. The U.S. Department of Energy's Hydrogen Fuel Cell Technology Office is targeting ultimate heavy-duty PEM fuel cell costs of $60/kilowatt (kW) by around 2050 (Marcinkoski 2019); however, that target is an uninstalled equipment cost for vehicle applications. Installing PEM fuel cells for stationary applications at the hundred-megawatt (MW) to gigawatt (GW) scale will require much more extensive structural and electrical balance-of-plant (BOP) equipment and labor for concrete pads, buildings, piping, fittings, instrumentation, and cabling, along with additional equipment such as inverters, medium- and high-voltage transformers, and stationary air coolers. Stationary power connected to the grid will also incur costs associated with land, permitting, interconnection fees, and the cost of developing transmission to the nearest grid interconnection point. The authors (we) are not aware of any published detailed analysis that includes these costs to determine the total cost of installing heavy-duty vehicle PEM fuel cells for large-scale stationary grid power applications. The analysis detailed in this report attempts to fill that knowledge gap.

Our study presents the detailed design and cost analysis of a 100-MW stationary power PEM fuel cell system that uses currently available PEM fuel cell modules sized for heavy-duty vehicle applications. We take PEM fuel cell module, inverter, and transformer costs from the 2024 National Laboratory of the Rockies (NLR) Annual Technology Baseline (ATB) (National Laboratory of the Rockies 2024) for low, mid, and high-cost scenarios. We capture additional BOP components such as air coolers, power electronics, pipes, valves and fittings, cabling and conduit, concrete pads, and buildings. Our analysis estimates the physical footprint of each component and subsystem using measurements of actual equipment and engineering judgment for component clearances and determines a resulting plant layout. We use that layout to estimate the required lengths of pipes, cables, and conduit; the required size of pipes using American Society of Mechanical Engineers B31.1 for water and coolant and B31.12 for hydrogen; and the required size of cables and conduit using National Fire Protection Association National Electric Code 70. We use these estimates, along with online vendor data bases, to estimate the costs of pipe, cable, conduit, valves, fittings, and instrumentation, and use engineering judgment and the *Estimator's Piping Man-Hour Manual* (Page 1999) to estimate labor costs for installing these components. The study also captures installation costs such as surveying and site preparation and indirect costs such as permitting; engineering, procurement, and construction; interconnection and transmission; overhead; taxes; and contingency. We use the work of Ramasamy et al. (2022) as the basis for a new framework for compiling these costs into a total overnight capital cost that can be used in techno-economic analyses to compare against competing power generation technologies. This framework, named "Fuel Cell Plant Layout and Cost Estimation Resource" or "FC-PLACER", is open source and publicly available at www.github.com/NatLabRockies/FC-PLACER. We use the resulting total overnight cost estimates to calculate PEM fuel cell power plant levelized cost of electricity (LCOE) for a range of capacity factors and hydrogen prices and compare against several natural gas combustion turbine (NGCT) scenarios.

Figure ES-1 shows the breakdown of total overnight system cost for the mid-case future cost scenario. The current total overnight cost, represented by the thin black line, is $1,352/kW in 2022 U.S. dollars; the cost reduces to $1,001/kW by 2050 in the mid-cost scenario. Most of the cost reduction comes from a reduction in fuel cell module cost, but reductions in inverter costs also contribute. Note this study assumes the plant physical design and efficiency remain the same over time, so potential cost reductions in structural and electrical BOP associated with higher fuel cell and power electronics volumetric power density, lower cooling loads, and lower hydrogen and cooling flow rates are not captured. Similarly, this study captures some of the potential cost reductions for plant hardware but does not capture any potential cost reductions associated with improved installation practices over time. Structural and electrical BOP costs might also be overestimated in this study because of the reliance on online, public-facing vendor websites for valve and fitting costs, while engineering firms could likely contract these components in bulk at lower prices. Designing the fuel cell stacks and modules for stationary power rather than for heavy duty truck transportation, which would likely result in larger fuel cells, could also reduce the cost and complexity of supporting infrastructure of pipes, cables, and other systems.

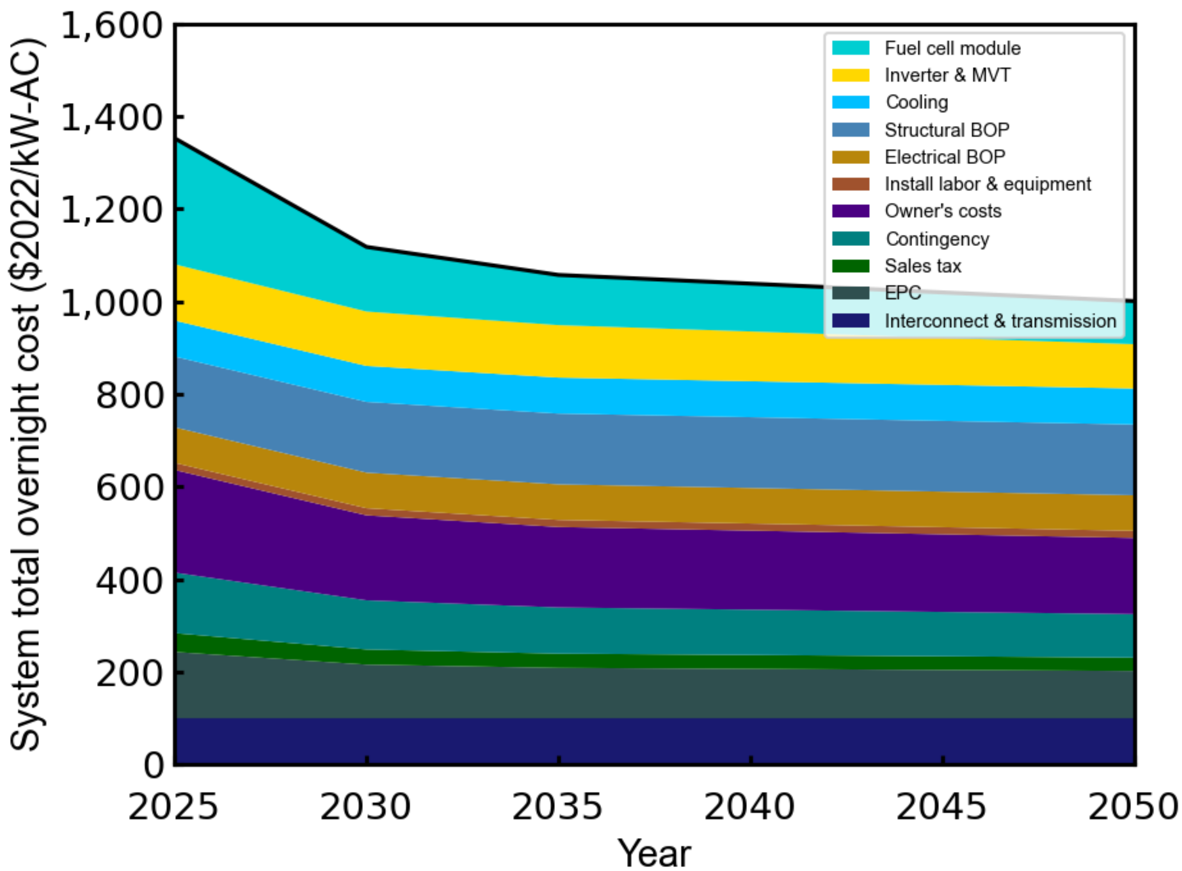

Figure ES-1. PEM fuel cell system total overnight cost breakdown for the mid-cost scenario

Figure ES-2 shows the total system overnight cost over time for all three future cost scenarios considered in this study. This plot suggests fuel cell and inverter costs could decrease enough to see a reduction of stationary PEM fuel cell plant total overnight cost of almost $300/kW within one decade for the mid-cost scenario. In the low-cost scenario, total overnight cost could drop to as low as $924/kW by 2050, a cost reduction of almost $430/kW. In the high-cost scenario, the cost is about $1,142/kW by 2050, a cost reduction of more than $200/kW. These future costs are within the range of current natural gas combustion turbine (NGCT) installed costs as estimated between $836/kW and $1,606/kW by Sargent & Lundy (2023). Natural gas turbine costs, however, have increased significantly due to a recent spike in electricity demand; some estimates put the actual cost of a natural gas combustion turbine (NGCT) at roughly $1,500/kW (GridLab et al. 2025) with natural gas turbine wait times on the order of three to seven years (Anderson 2025; Cunningham 2025; Cohen et al. 2025). In this context, the PEM fuel cell plant capital costs derived in this study are potentially substantially lower than the capital cost of natural gas turbine power plants, which could make them competitive depending on the cost of hydrogen fuel.

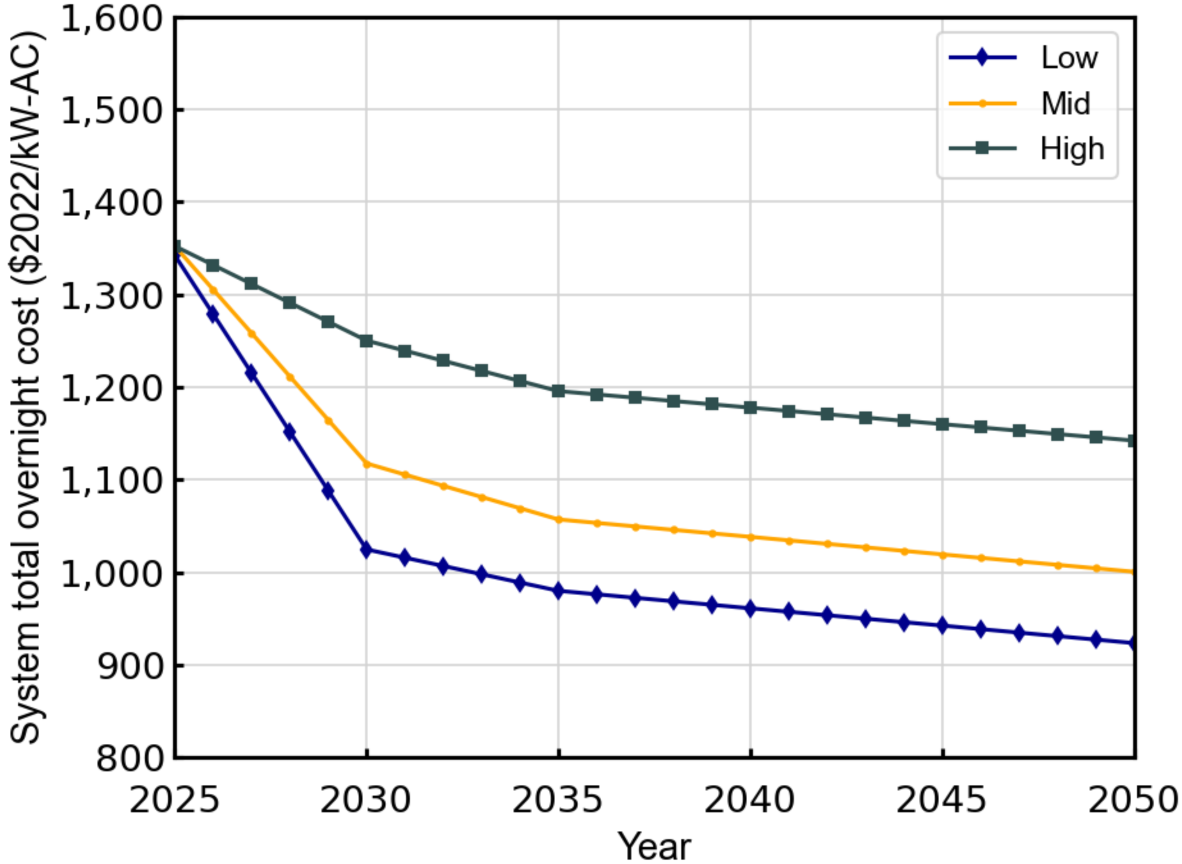

Figure ES-2. Total PEM fuel cell system overnight costs in the future for three different scenarios

The “Low”, “Mid”, and “High” cost scenarios correspond to “Advanced”, “Mid”, and “Conservative” cost cases for PEM fuel cells and inverters from the NLR 2024 ATB.

Figure ES-3 shows the LCOE of NGCT and PEM fuel cell plants as a function of capacity factor from 2% to 10%, which covers most capacity factors seen by NGCTs in the U.S. between 2014 and 2023 (U.S. Energy Information Administration 2024a; 2024b). This figure assumes the

NGCT plant has a capital cost of $1,500/kW and access to natural gas at a price of $4.52/MMBTU, and that PEM fuel cell plants have 2025 total overnight cost from this study and access to hydrogen at a price of $1.21/kg. It illustrates that PEM fuel cell plants can achieve lower LCOE for peak power applications with capacity factors less than approximately 5.5%. The magnitude of the difference is small, however, and overshadowed by the significant sensitivity of LCOE to small changes in capacity factor.

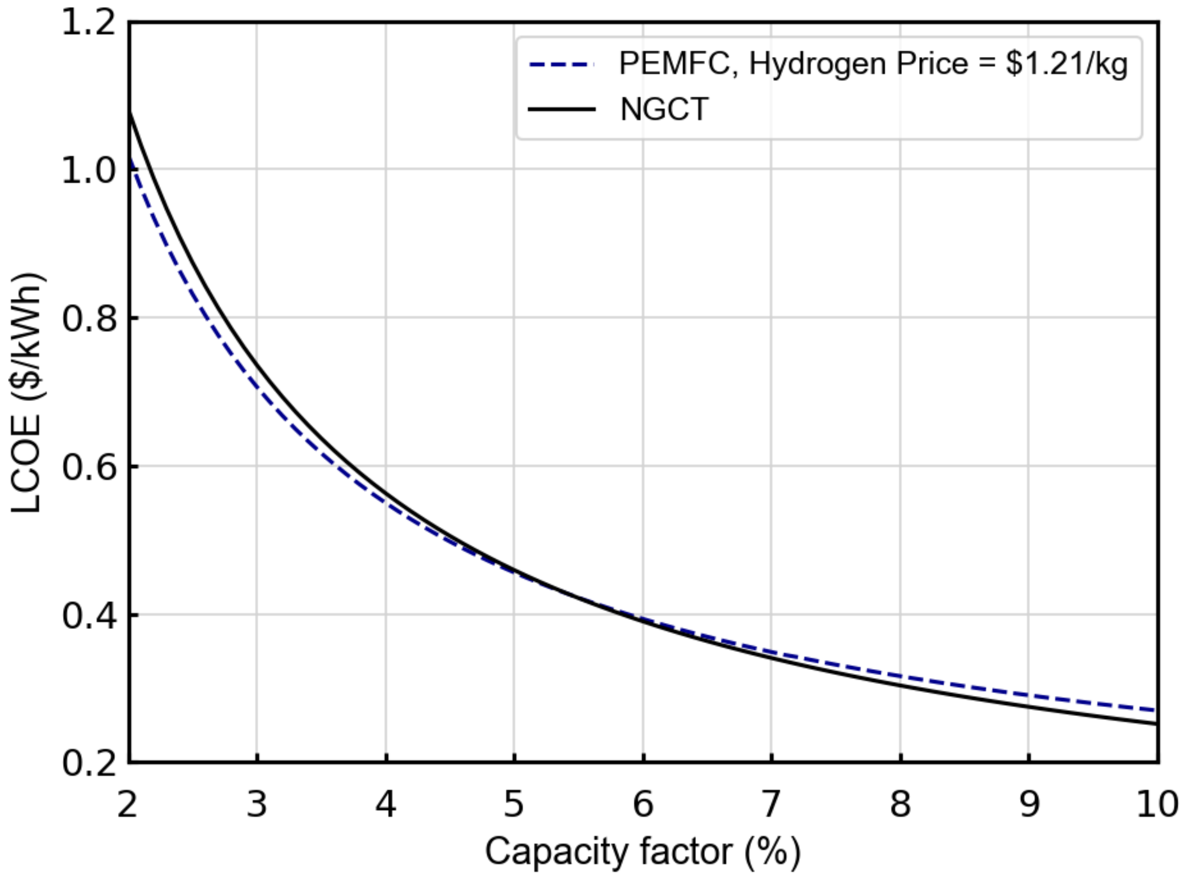

Figure ES-3. LCOE of NGCT plants and PEM fuel cell plants with 2025 total overnight cost as a function of capacity factor

Figure ES-4 shows difference between PEM fuel cell LCOE and NGCT LCOE as a function of capacity factor and as a function of hydrogen price for the PEM fuel cell plants. This figure illustrates that applications that require higher capacity factors demand lower hydrogen prices for PEM fuel cells to be competitive; conversely, at lower capacity factors, PEM fuel cells can be competitive with higher hydrogen prices. This occurs because as capacity factor increases, the fuel price becomes a more significant driver of LCOE. Figure ES-4 also illustrates the magnitude of the difference in LCOE as a function of hydrogen price. For example, at a capacity factor of 3.5%, PEM fuel cell plants achieve a similar LCOE at approximately $1.5/kg ($11.2/MMBTU). If the hydrogen price were $0.5/kg ($3.73/MMBTU) higher or lower, however, it would only change the LCOE by approximately 5%. In practice, the efficiency and fuel price will likely dictate the capacity factor that a plant achieves and determining that capacity factor requires production cost modeling. This analysis of LCOE indicates, however, that PEM fuel cell plants would likely be utilized similarly to NGCTs if they have access to hydrogen at approximately $1.21/kg.

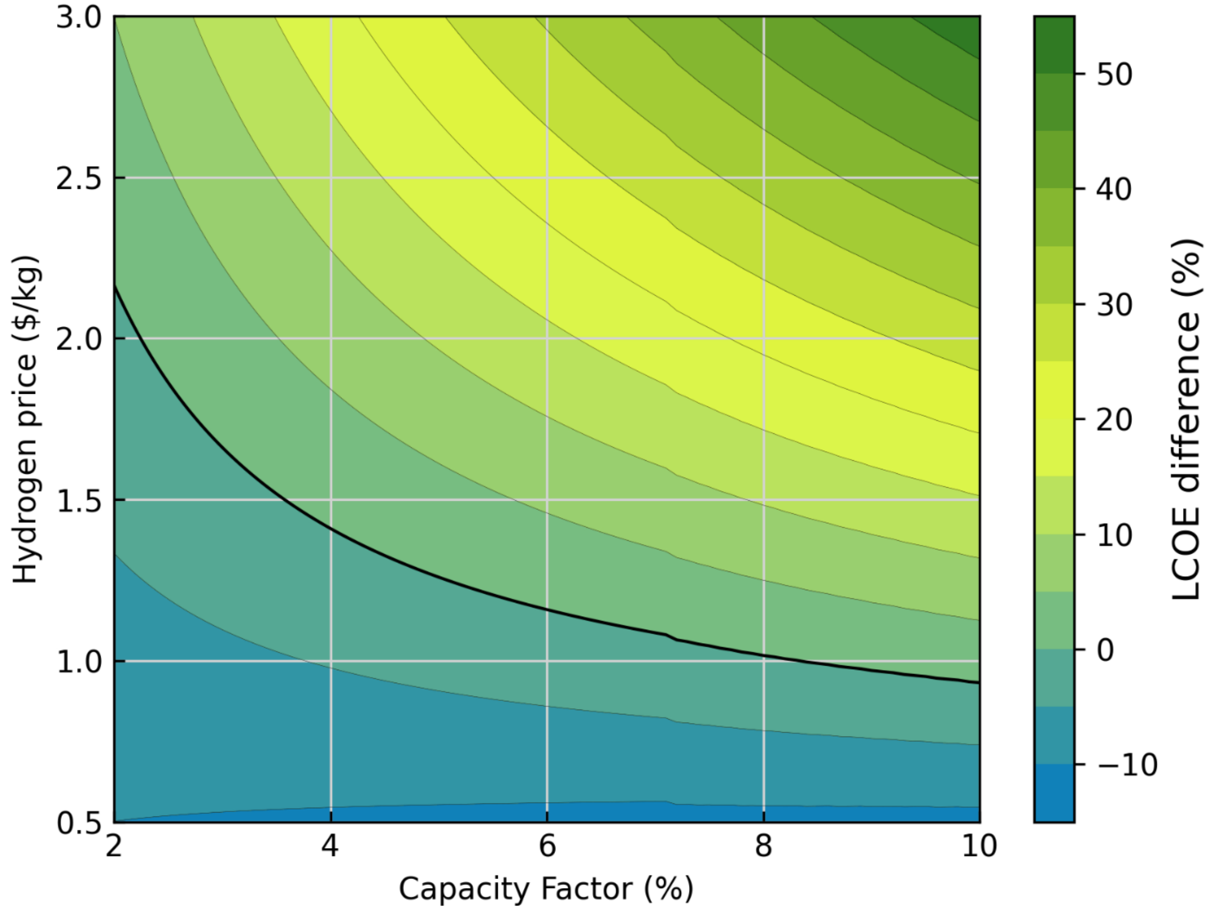

Figure ES-4. Difference in LCOE between PEM fuel cell plants with 2025 total overnight cost and NGCT plants as a function of capacity factor and hydrogen price

Note that both PEM fuel cell and NGCT LCOE vary with capacity factor, but only PEM fuel cell plant LCOE varies with hydrogen price. Natural gas cost was assumed fixed at $4.52/MMBTU for this figure. The range of hydrogen prices is equivalent to $3.72/MMBTU—$22.37/MMBTU. The small discontinuity at approximately 7% capacity factor is caused by a stack refurbishment that must occur for a PEM fuel cell plant operating at that capacity factor over a 40-year plant life with a durability of 25,000 hours.

Finally, it is useful to consider the large required capacity of peaking power plants in the U.S. In 2021, there were about 1000 peaking power plants with a capacity of about 237,000 MW, nearly a quarter of the U.S. total generation capacity, which generated about 130 TWh of power and thus operated at an average annual capacity factor of about 6% (U.S. Government Accountability Office 2024). The projected growth in power demand and replacing the many old peaking plants will require significant new peaking plant installations. With the projected costs for peaking power plants using heavy duty vehicle PEM fuel cells compared to NGCT costs detailed above, the savings from these PEM plants could potentially be substantial.

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Introduction

Electricity demand in the United States is expected to grow by 35%–50% over the next 15–25 years, driven largely by data centers, manufacturing, electrification of residential and commercial space and water heating, and electrification of transportation (National Electrical Manufacturers Association 2025; American Clean Power 2025). This rapid growth in electricity demand is currently contributing to increased costs and long delivery times for natural gas power plants, with the cost of natural gas combustion turbines (NGCT) in the neighborhood of $1,500/kW and natural gas combined cycle (NGCC) plants now hitting $2,400/kW in some markets with wait times on the order of three to seven years (Anderson 2025; Cunningham 2025; Cohen et al. 2025; GridLab et al. 2025). Three gas turbine manufacturers -GE Vernova, Siemens Energy, and Mitsubishi Power – are responsible for the majority of gas turbine supply in the U.S., and all three face backlogs (Shenk 2025; Patel 2025). Higher efficiency NGCC plants are particularly attractive for large-scale data centers that operate around the clock, while demand for lower-efficiency NGCTs is driven by the reserve margin needs of grid operators. Given this environment, cost effective alternatives to gas turbine simple cycles for peaking power capacity could reduce energy prices and improve grid reliability in years to come. Hydrogen-fueled proton exchange membrane (PEM) fuel cell power plants could be a useful complement to gas turbine power systems by enabling gas turbines to be used in their highest value role in combined cycles rather than in lower efficiency peaking plants that only operate for short durations of the year. Hydrogen is an attractive fuel because it can be produced from a variety of resources (Connelly et al. 2020), including naturally occurring geologic reserves (Ellis and Gelman 2024). PEM fuel cells could help employ hydrogen to produce electricity because of their rapid startup and response times, potential low module costs, and relatively high efficiency. While low-cost geologic hydrogen could be used in high-efficiency, high capacity factor plants for base-load applications like data centers, hydrogen derived from natural gas or higher-cost sources could be deployed for peaking applications where plant capital cost matters more than fuel cost or efficiency. Although much attention has been paid to the economics of PEM fuel cells for automotive applications (James and Huya-Kouadio 2024), less attention has been given to the economics of employing PEM fuel cells for grid-scale stationary power.

Historic cost data for stationary PEM fuel cell plants are limited to small-scale applications with net power ratings generally less than 1 kilowatt (kW). These fuel cells were designed for baseload operation and therefore had higher platinum loading, more robust membranes, etc. to improve durability, all of which raised costs relative to PEM fuel cells designed for transportation. As a result, the studies that rely on this historic data demonstrate relatively high costs for stationary PEM fuel cell plants (Zakeri and Syri 2015; Schmidt et al. 2017). Previous bottom-up cost studies also focused on small-scale plants on the order of hundreds of kilowatts providing baseload power (Battelle 2016; Gorgian and Kern 2023) and thus also predict relatively high system costs. The EIA Electricity Market Module, another popular reference for stationary fuel cell costs, estimates stationary fuel cell installed cost at $7,291/kW (U.S. Energy Information Administration 2023b). However, this estimate is for solid oxide fuel cells at the 10-megawatt (MW) scale providing baseload power, and of that total, more than $1,000/kW is associated with the fuel cell stacks alone, and an additional $1,600/kW is associated with the mechanical balance-of-plant (BOP) (Sargent & Lundy 2019). Other studies have suggested, however, that PEM fuel cell systems designed for mobile applications could have much lower equipment costs, potentially as little as a few hundred dollars per kilowatt for the entire module (Huya-Kouadio and James 2023; James 2018). This is much lower than the EIA estimate for solid oxide fuel cells, lower than the typical \$800/kW−\$1,600/kW total overnight cost associated with natural gas combustion turbines and combined cycles (Sargent & Lundy 2023) and does not count recent rising prices associated with rapidly increasing demand, and much lower than the cost of natural gas turbines when taking those demand-induced cost increases into account (Anderson 2025). These rising prices have resulted in NGCT and NGCC plant costs increasing to around \$1500/kW and \$2,400/kW, respectively, with wait times on the order of three to seven years (Anderson 2025; Cunningham 2025; Cohen et al. 2025; GridLab et al. 2025). Uncertainty remains regarding the cost of implementing mobile PEM fuel cell stacks for stationary peak power applications at grid scales and whether they could be cost-competitive with existing peaking technologies once all installation costs are considered.

This study presents detailed design and cost analysis of a 100-MW stationary peak power PEM fuel cell system that uses currently available PEM fuel cell-stack modules sized for heavy-duty vehicle applications. The analysis captures the costs of BOP equipment such as cooling and power electronics, piping for hydrogen and coolant, valves and fittings, direct-current (DC) and alternating-current (AC) electric cabling and conduits, concrete pads and buildings, site preparation, and necessary subsystems, including a high-voltage transformer substation and transmission to connect to the grid. The resulting estimates of total overnight capital cost are then used to calculate the potential LCOE of PEM fuel cell peaking power plants and compare them against NGCTs, which are the primary technology currently used to meet peak electricity demand. The focus here is on peaking duty which low-cost mobile PEM fuel cells can supply, as described in Hunter (2021).

The rest of this report is organized as follows. Section 2 presents the modeling methodologies employed in this study, including quantification of primary equipment costs, BOP costs, and indirect costs, and provides methodologies used to estimate future primary equipment costs. Section 3 provides results for a 100-MW plant with estimated current and future fuel cell technology equipment costs. Section 4 provides a discussion on these results and the limitations of this study, and Section 5 provides conclusions.

1 Methodology for Calculating Fuel Cell Plant Cost

This study determines total overnight cost of stationary fuel cell plants by quantifying and summing the costs of primary equipment with various installation and indirect costs. Total overnight cost is defined as the total cost to build a plant with current prices and assuming interest accrued during the construction period is zero. This calculation enables comparison of fuel cell plant costs with the capital costs of other power generation technologies. Gas combustion turbine peaking power plants are a particularly interesting point of comparison because rapidly growing demand for electricity, particularly for data centers, is raising the prices and delaying delivery of gas turbines (Anderson 2025; Cunningham 2025; Cohen et al. 2025).

To facilitate comparisons to other technologies, this study broadly follows the definitions for total plant cost and total overnight cost given in the National Energy Technology Laboratory (NETL) Quality Guidelines for Energy System Studies (Theis 2021). These definitions are similar to those from the National Laboratory of the Rockies (NLR) Electricity Annual Technology Baseline (National Laboratory of the Rockies 2024) in that it quantifies primary process equipment; BOP equipment; electrical infrastructure and interconnection; supporting facilities and components; installation labor; equipment; engineering, procurement, and construction (EPC); site development costs, permitting, insurance and legal fees, preliminary feasibility and engineering studies, taxes, and so on. We report both total overnight cost for consistency with NLR's ATB and NETL's techno-economic assessments and total installed cost, which is equal to the total overnight cost minus the owner's costs (pre-production costs, inventory capital, spare parts, cost of acquiring financing, and so on). Total installed cost is frequently used in analyses performed using H2A (National Laboratory of the Rockies 2018; Penev 2021) and H2FAST (National Laboratory of the Rockies 2025) under the U.S. Department of Energy's hydrogen program sponsorship, which include owner's costs separately as working capital. Readers should ensure they properly account for various owner's costs and construction period financing when using these results for techno-economic analyses. This study calculates all costs using a mathematical framework adapted from Ramasamy et al. (2022).

The rest of this section presents the cost methodology for the fuel cell power plant, including primary process equipment, supporting facilities, labor, and so on. Table 1 provides an outline of the cost categories and overall structure employed in this study. Although primary process equipment such as cooling and power electronics might commonly be referred to as "balance of plant," we follow the approach taken Ramasamy, et al (2022), in differentiating structural BOP, which includes concrete pads, buildings and structures, valves, fittings, instrumentation, roads, fencing, and other site preparation costs, and electrical BOP, which includes conduit and cable, junction/combiner boxes and switchgears, instrumentation and controls, and an on-site high-voltage transformer substation.

Table 1. Cost Categories and Structure

Cost Category	Subcategories
Primary process equipment	Fuel cell modules Cooling radiators Inverter/medium-voltage transformer (MVT) units
Structural BOP	Fuel cell buildings (FCBs) Cooling pad foundation Piping for hydrogen, water, and coolant Valve, fittings, and safety instrumentation Security fencing Operations and maintenance and controls building Site preparation
Electrical BOP	Conduit and cable Grounding cable Junction/combiner boxes Combining switchgears On-site high-voltage transformer substation Controls and instrumentation On-site transmission
Installation labor and equipment	
EPC costs	
Transmission and interconnection	
Contingency	
Sales tax	
Owner's costs	Preproduction Inventory capital Land Financing Other (feasibility studies, permitting, legal, etc.)

1.1 Plant Layout and Design

Figure 1 shows a process diagram of a PEM fuel cell system for stationary power generation. Primary equipment includes the fuel cell modules, fuel cell module coolant radiators, and power electronics subsystem. The fuel cell module contains the fuel cell stack, air compressor, an internal cooling loop to maintain high-purity coolant for direct cell stack cooling, and a humidifier and anode recirculation. The external cooling loop interfaces with the fuel cell subsystem internal cooler via a heat exchanger and transfers waste heat to the environment via a tube-fin-type air cooler. The power electronics subsystem includes an inverter and an MVT, and a high-voltage transformer substation is also necessary to boost the voltage to grid levels.

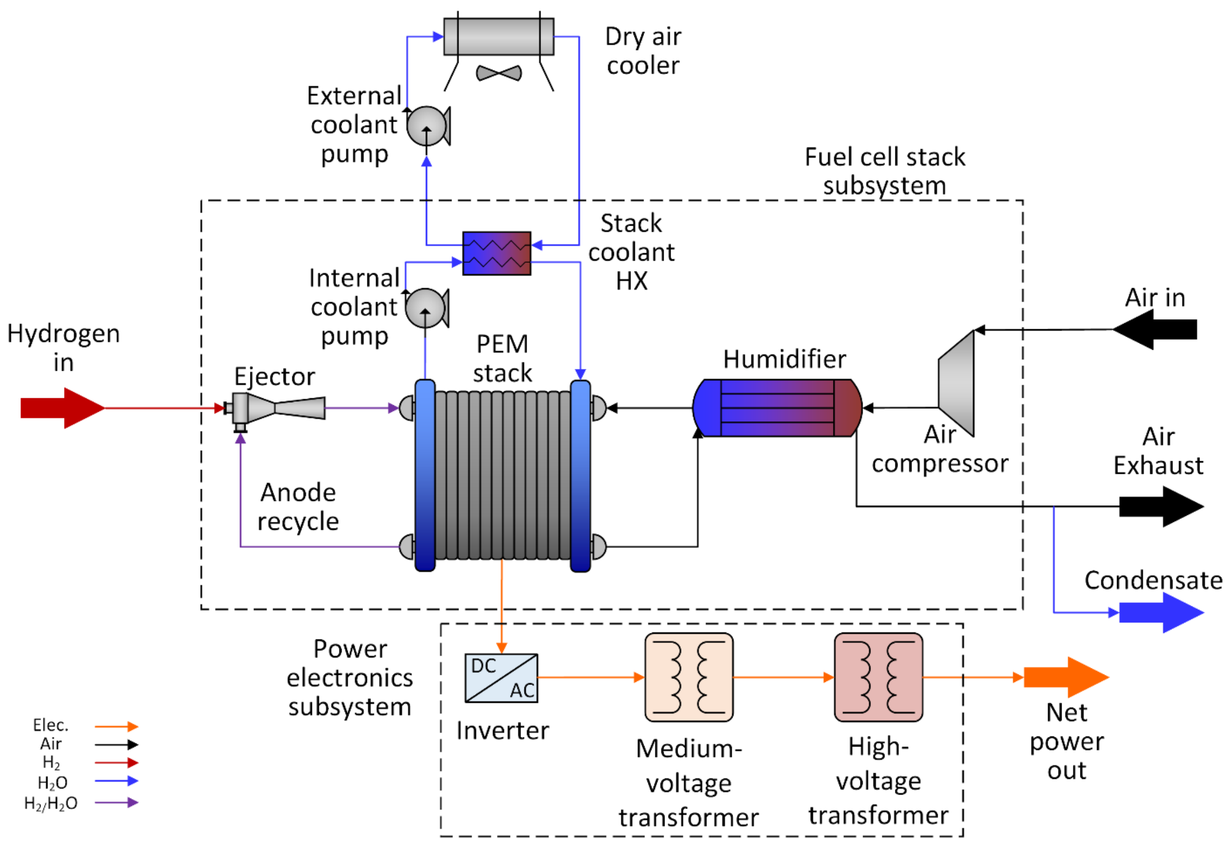

Figure 1. PEM fuel cell system process model

The fuel cell stack "subsystem" or "module" contains all of the critical BOP for the fuel cell to function, including an air compressor, humidifier, anode recycle (either an ejector or a recycle blower), and an internal cooling loop. The power electronics subsystem includes an inverter, a medium-voltage transformer, and the high-voltage transformer substation. While this figure shows only one PEM fuel cell stack subsystem, in practice there would be many. Subsequent figures illustrate how different plant subsystems are scaled.

Although Figure 1 is illustrative of the system process, it does not capture the overall layout of the plant, which must consider the physical dimensions of each component, component spacing requirements, and cable and pipe run lengths to connect various subsystems. Although these components might be located close to one another within a heavy-duty vehicle, and several fuel cell manufacturers offer stationary fuel cell systems at the single-megawatt scale using International Organization for Standardization shipping containers or electrical skids (Plug Power 2024; Ballard 2024; Accelera 2024), stationary fuel cell systems built at the hundreds of megawatts to gigawatts scale would be constructed somewhat differently. The Institute for Sustainable Process Technology recently released a report detailing what gigawatt-scale PEM and alkaline electrolysis facilities constructed by 2030 might look like (Noordende and Ripson 2022). Although PEM electrolysis is not a direct analog for PEM fuel cells, this case study illustrates large-scale hydrogen facilities will likely segregate different plant subsystems to take advantage of economies of scale, rather than simply stringing together multiple small-scale stand-alone systems. Because such a system has never been constructed, the various installation and indirect costs are highly uncertain. This study aims to quantify those costs.

Figure 2 shows a qualitative diagram of a hypothetical stationary PEM fuel cell power plant layout. We envision such a plant would have independent pads for cooling, the fuel cell modules and power electronics, and the high-voltage transformer substation. The plant would also need a security checkpoint and controls and maintenance building. Hundred-kilowatt-scale heavy-duty vehicle PEM fuel cells could be stacked on pallets within a warehouse-like structure.

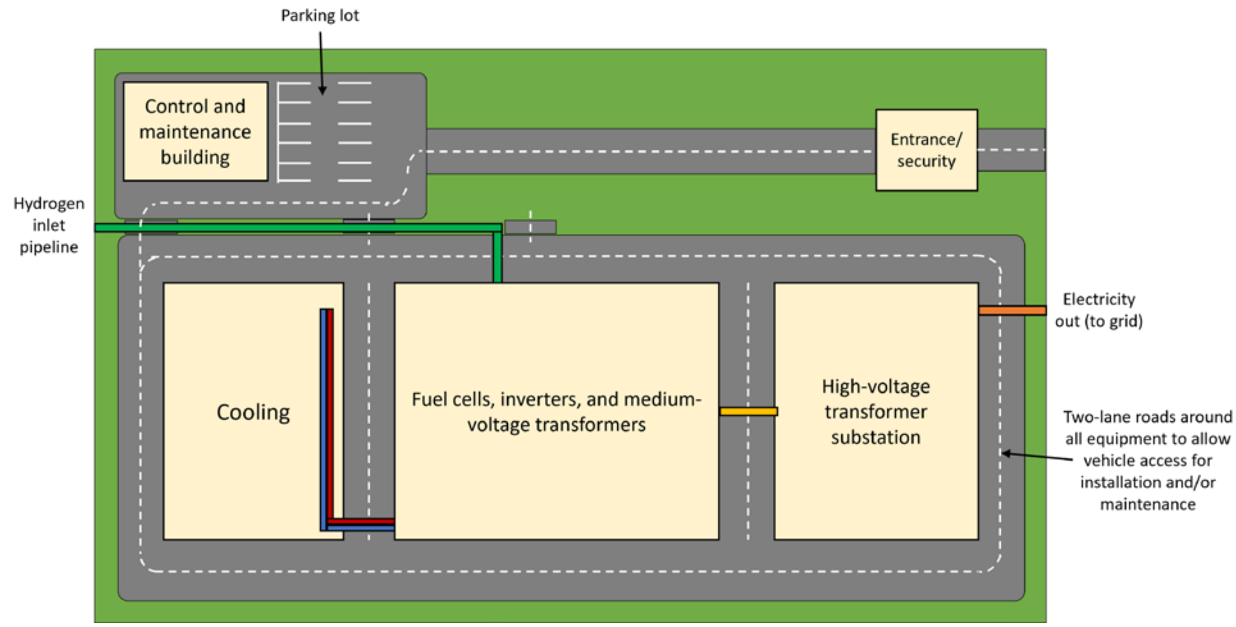

Figure 2. Stationary fuel cell plant layout, as seen from above

The beige squares illustrate where different sub-systems are located relative to each other. The green line represents the plant's hydrogen feed, the red and purple lines illustrate cooling hot and cold pipes, the yellow line represents medium-voltage AC cabling, and the orange line represents high voltage AC power exported from the plant. The dark gray surfaces with dashed white lines represent access roads surrounding each subsystem.

1.1.1 Fuel Cell and Inverter/Medium-Voltage Transformer Pad

Figure 3 shows a qualitative diagram of the layout of the pad containing the heavy-duty vehicle PEM fuel cell modules and inverter/MVT units. This study assumes PEM fuel cell power plants would employ inverters based on technology developed for solar PV, many of which are designed for a maximum DC voltage of 1,500 volts DC (V_{DC}) and total power handling of around 3 MW_{AC}. Many heavy-duty vehicle PEM fuel cell products have output voltages in the range of 400 to 800 V_{DC}, so multiple modules could be wired in series to achieve total DC voltage in the range of 1,000−1,500 V_{DC}, and tens of modules could be wired to a single solar PV inverter unit. This approach matches total stack voltage and current to the inverter voltage and current handling capabilities. Because 1,500 V_{DC} is relatively low for a power plant of the hundred megawatt to gigawatt scale, we assume the plant would employ inverter/MVT units located close to the fuel cell modules to reduce run lengths of low-voltage DC cabling, which could get very expensive because of the high current-carrying capacities that would be required of this cabling. Having an array of inverters and MVTs connected to individual groups of fuel cells also facilitates easier plant turndown and allows the plant to keep operating while maintenance is performed on individual fuel cell modules and/or inverters.

We assume fuel cell modules are housed within buildings but the inverter-MVTs are installed outside, as these packages are typically already housed within weatherproof containers. As Figure 3 illustrates, the layout alternates between rows of fuel cell module buildings and double rows of inverter-transformer units to minimize DC cable runs while maximizing accessibility to each component for maintenance. FCBs on the edge of the plant might only have one double row of fuel cell modules, whereas buildings in the middle of the plant might contain two double rows of fuel cell modules. Within each building, feedstock hydrogen and coolant are supplied to the fuel cell modules via underground pipes, and the output coolant extracted from the modules is run out of the building via underground pipes as well. We assume the FCBs are adequately ventilated to allow fresh intake air for the fuel cell modules and hot exhaust air is vented out the roof of each building via high-temperature air ducts. We also assume each air duct has a condensate trap at the bottom that directs condensed water into a pipe running under the FCB floor at a gradient to allow condensed water to flow out of the building. Each pair of fuel cell module rows requires adequate clearance on one side for the air ducts and on the other side for a narrow-aisle forklift for performing maintenance, and each pair of inverter/MVT units requires adequate spacing for installation and maintenance. Section 2.2 provides detailed assumptions regarding component size and space requirements.

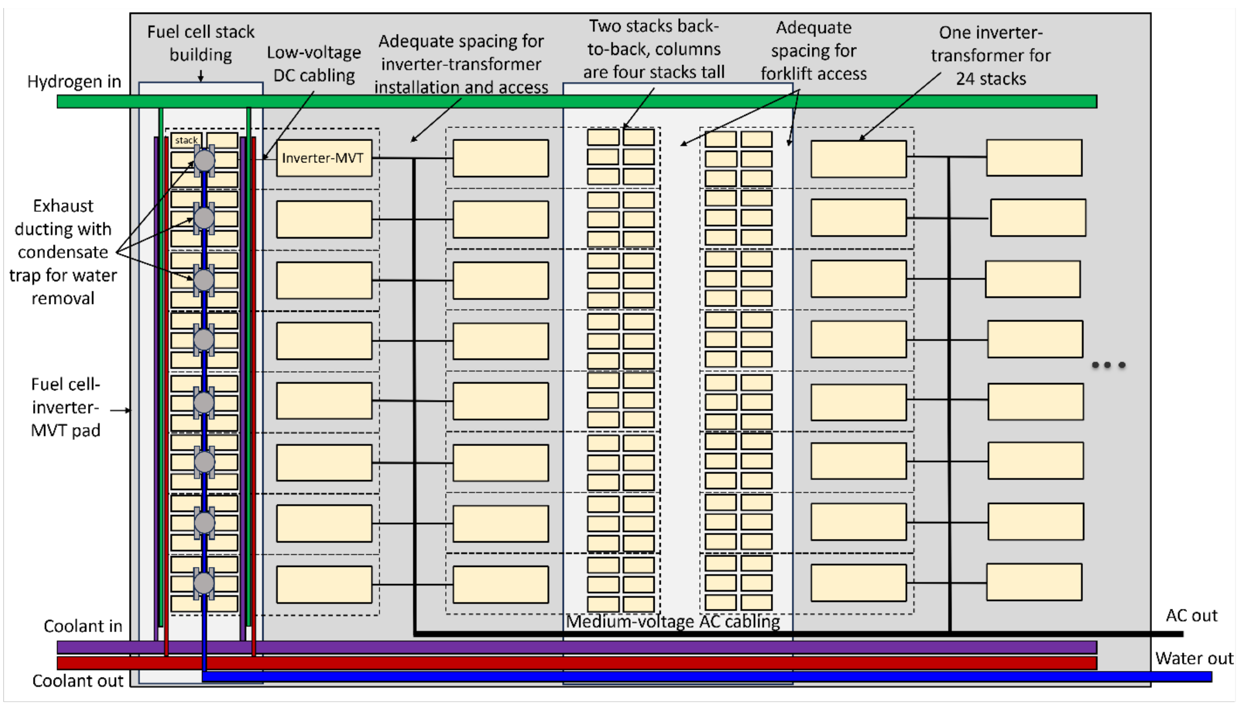

Figure 3. Layout of concrete pad for fuel cells (housed in buildings) and inverter/MVT units, as it would appear from above

The small beige squares represent individual columns of fuel cell stacks, each of which are four stacks tall. The light gray perimeter around the rows of fuel cell stacks represents the building that contains each bank of stacks, and the darker gray square represents the overall fuel cell stack-inverter-MVT pad. The green line represents the hydrogen delivery pipe, the purple and red lines represent cold and hot coolant pipes, and the blue lines represent water pipes. The small black lines represent low-voltage DC cabling, and the medium and large black lines represent medium-voltage AC cabling.

1.1.2 Cooling Radiator Pad

Heat extracted from the fuel cell modules via coolant is rejected to the atmosphere via coolant-to-air heat exchangers. We assume industrial cooling units are used for this purpose to reduce the coolant temperature from 70°C to 50°C with a 50/50 mixture of propylene glycol and water as the coolant. The total required coolant flow rate was determined using process modeling of a PEM fuel cell system in Aspen Plus (aspentech 2024), and the cost of industrial coolers necessary to provide the corresponding cooling load was acquired by soliciting a quote from Güntner (Güntner, personal communication, 2024). Note costs for cooling can vary depending on the annual weather in a given location; for this study, we selected cooling costs based on a location near Houston, Texas, as this represents costs that are near the middle of the possible range for the continental United States. Figure 4 shows a qualitative representation of the potential layout of the cooling pad. Although this study assumes waste heat is rejected to the atmosphere, it could be possible to use it for certain low-temperature processes, such as heating water.

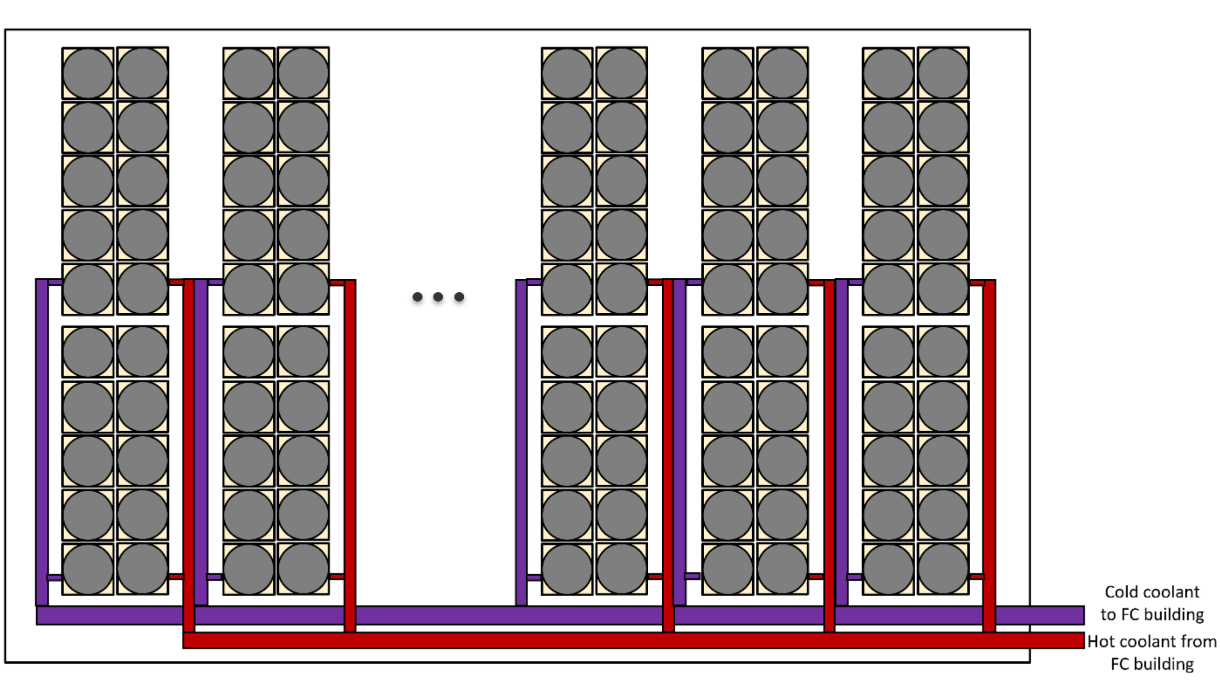

Figure 4. Layout of pad with industrial air coolers, as it would appear from above

The circles represent individual fans for cooling units; as depicted, each cooling unit has ten fans. The purple lines represent cold coolant pipes, and the red lines represent hot coolant pipes.

1.2 Primary Process Equipment Selection and Sizing

Because this study aims to quantify costs associated with buildings, land, and BOP components such as cabling and piping for PEM fuel cell systems at large scales for which no previous plant data exist, it is necessary to specify dimensions for each major piece of equipment. This section presents surveys of products available at the time this analysis was performed to demonstrate typical and selected dimensions.

1.2.1 Heavy-Duty Vehicle PEM Fuel Cells

Table 2 provides a survey of current vehicle PEM fuel cell module products. Sizes range from 60 kW to 125 kW, with typical operating voltages between 400 and 750 V_{DC}. All these products include several BOP components necessary for installation and operation within a vehicle, including humidification, air supply, hydrogen recirculation, and some degree of power electronics; they exclude external cooling (which would typically be done by the radiator of a vehicle) and any BOP necessary for stationary operation that is not necessary for vehicular operation. For this study, we select the Plug Power ProGen for estimating plant layout dimensions because we feel it is representative of the current overall heavy-duty vehicle fuel cell market in terms of power rating, size, and operating design parameters such as current and voltage. Its voltage range also makes it suitable for wiring two modules in series to produce a total operational voltage of 1,000 to 1,500 V_{DC}, which aligns well with the inverter products discussed in the next section. Note this is not an endorsement of this specific product or brand; rather, we are simply employing dimensions and operating parameters for an actual PEM fuel cell product we feel is representative of the current market and simplifies the analysis at hand. For fuel cell efficiency, we take an end-of-life value of 44.7% on a lower heating value (LHV) basis from Huya-Kouadio and James (2023). Using that publications estimated beginning of life and end-of-life voltages, we estimate beginning of life efficiency at 50.5% on an LHV basis.

Table 2. Vehicle PEM Fuel Cell Products

Parameter	Units	Ballard FCmove-XD	Toyota TFCMC-B	Plug Power ProGen
BOP included		Humidification, air supply, DC-DC converter, hydrogen recirculation and preheater, etc.	Air supply, hydrogen supply, cooling, power control	Humidification, air supply, fuel regulation, cooling, etc.
Net power	kW_{DC}	120	60 or 80	125
Minimum voltage	V_{DC}	520	400	500
Maximum voltage	V_{DC}	750	750	750
Maximum current	A_{DC}	231		
Dimensions	mm x mm x mm	895 × 735 × 500	890 × 630 × 690	1430 × 700 × 400
Volumetric power density	W/L	332	155−387	319
Weight	kg	238	259	363
Reference		(Ballard 2024a)	(Toyota 2023)	(Plug Power 2023)

1.2.2 Inverters and Medium-Voltage Transformers

Table 3 shows a small survey of inverter and MVT products; three of these are only inverters, whereas two are inverter/MVT packages. All these products have a maximum DC input voltage of 1,500 VDC and total power handling capabilities in the 3−4 MW range, depending on temperature. For this study, we select the GE FlexInverter power station for plant layout calculations because its voltage, current handling, and dimensional characteristics make it a good match for the Plug Power ProGen fuel cell module, and because having both an inverter and MVT within one package simplifies installation and reduces the required length of low-voltage DC cabling. Once again, this is not an endorsement of this specific product.

Table 3. Inverter and MVT Products

Parameter	Units	GE Flex Inverter	Siemens (Gamesa) Proteus PV 4100	FIMER Central Inverter PVS980-58	GE Flex Inverter Power Station	FIMER Compact Skid for US
Product type		Inverter	Inverter	Inverter	Inverter + MVT	Inverter + MVT
Minimum DC voltage	V_{DC}	851	835	850	853	850
Maximum DC voltage	V_{DC}	1,500	1,500	1,500	1,500	1,500
Maximum DC current (up to 40°C/ at 50°C)	A_{DC}	4,200/3,700	2 × 2,500/2 × 2,313	5,300	4,200/3,700	2,899
AC output power (up to 40°C/ at 50°C)	MVA	3.39/3.00	4.10/3.79	4.23/3.85	3.36/2.98	4.23/3.85
AC output voltage	V_{AC}	600	600	600	2,200/33,000/34,500	12,470 to 34,500
Max AC current (up to 40°C /at 50°C)	A_{AC}	3,263/2,886	3,940	4,070/3,700	88/59/56; 78/52/50	
Inverter discharging efficiency (max/EU/CEC)	%	98.9/98.6/98.7	99.5/99.2/99.0	98.9/98.6/98.5	97.8/97.6/97.7	
Dimensions	m × m × m	2.0 × 2.4 × 2.9	4.3 × 1.0 × 2.25	5.6 × 1.6 × 2.2	6.1 × 2.4 × 2.9	8.5 × 2.9 × 2.6
Weight	kg	4,050	4,045	6,000	17,000	
Standard operating temperature range	°F	14 to 131	−4 to 140	−4 to 122	14 to 141	
Reference		(General Electric 2023a)	(Gamesa-Electric 2023)	(Fimer 2023)	(General Electric 2023b)	(Fimer 2023)

1.2.3 Cooling Radiators

This study employs cooling radiator costs and dimensions from Güntner (Güntner, Personal communication, 2024) that are tailored specifically to the cooling load required by the PEM fuel cells, assuming a Houston, Texas, location. The cooling units are 2.4 m wide by 12.23 m long, and a Houston location requires 30 of them to provide adequate cooling for 100 MW_{AC} of PEM fuel cells with LHV efficiency of 44.7% at end-of-life.

1.2.4 Selected Equipment Dimensions, Spacing, and Configuration

Table 4 gives the dimensions of selected equipment along with its minimum required spacing and assumed grid pattern. The fuel cell module and inverter/MVT grid patterns were selected together to allow good spatial matching between each inverter/MVT and the fuel cell modules that it serves. We assume fuel cell modules will be installed with four modules running vertically in banks of two rows that are 30 modules long, which in total would require 10 inverter/MVT units per bank. This results in each inverter/MVT servicing a "pod" of 24 fuel cell modules clustered into a grid of 2 × 3 × 4. Banks of fuel cell modules are spaced from each other by 10 feet (approximately 3 meters, m) to allow space for a narrow-aisle forklift to perform maintenance on the fuel cell modules. We ensure at least 3 m of spacing between inverter/MVTs for access and maintenance, which is easily met by equally spacing 10 inverter/MVTs down the length of a fuel cell module row that is 30 modules long. We allow 10 m of spacing between rows of inverter/MVTs for ease of access and installation. For the air cooler pad, the length of each row is determined by the required spacing of each unit and the total length of the FCBs; the number of rows is then determined by thermal duty of each cooling unit and the total required thermal duty of the plant. The cooling pad, FCBs, and high-voltage transformer substation are each surrounded by a road wide enough for two lanes of traffic to ensure adequate space for access, maintenance, and installation, as illustrated in Figure 2.

Table 4. Selected Equipment Dimensions and Configuration

Parameter	Units	Fuel Cell Module	Inverter + MVT	Air Cooler	Aisles Around Fuel Cell Modules	Aisles Between Inverter/MVTs
Dimensions	mm × mm × mm	1,430 × 700 × 400	6,100 × 2,400 × 2,900	2,400 × 12,238 × 2,818	3048 × fuel cell module row length	8,000 × fuel cell module row length
Minimum required spacing	mm × mm × mm	500 × 200 × 100**	8,000 × 200 × 0	0 × 1,000 × 0		
Grid Layout	N/A	2 × 30 × 4 per bank*	1 × 10 per bank*	Total row length set by FCB row length; # of rows set by row length and total required cooling	One aisle on either side of back-to-back fuel cell module rows	One aisle between inverter/MVTs

*Multiple banks required for the entire plant.
**Vertical distance between fuel cell modules

1.2.5 Current Primary Equipment Costs

Table 5 gives the primary equipment cost assumptions. For fuel cell module costs, we employ the 2025 mid-case value of \$236/kW from the 2024 NLR Transportation ATB (National Laboratory of the Rockies 2024). We approximate the current inverter/MVT costs by summing the inverter and transformer costs derived by Ramasamy et al. (2023) and used in the 2024 NLR Electricity ATB (National Laboratory of the Rockies 2024). As mentioned previously, Güntner provided quotes with the individual cooling unit cost and the number of cooling units required for different thermal loads; we used this information to develop a correlation between the number of required cooling units and the PEM fuel cell module efficiency at end-of-life. In this study we assume end-of-life fuel cell module efficiency is 44.7% on a lower heating value basis (Huya-Kouadio and James 2023) Beginning-of-life efficiency will be higher, but cooling systems must be sized for stack end-of-life to ensure the plant can hit rated power capacity for the duration of its life. Note that end-of-life is typically defined as the point at which the stack experiences a 10% reduction in voltage relative to beginning-of-life (James and Huya-Kouadio 2024; Kleen and Gibbons 2024). Some fuel cell operators might choose to derate their systems near end-of-life, whereas others, such as this one, base system-rated capacity on end-of-life performance. This approach results in a total cooling cost of approximately \$67/kW$_{DC}$ for the current cost scenario. Note the final cost in \$/kW$_{AC}$ of net power out will be higher for both cooling and fuel cell modules because those costs are calculated after considering plant parasitic losses.

Table 5. Current Primary Equipment Cost Assumptions

Component	Cost (2022 USD)	Reference
Fuel cell module	\$236/kW$_{DC}$	(National Laboratory of the Rockies 2024)
Inverter/MVT	\$99/kW$_{AC}$	(Ramasamy et al. 2023)
Fuel cell coolant radiators	\$67/kW$_{DC}$	(Güntner, Personal communication, 2024)

1.2.6 Future Primary Equipment Costs

This study estimates future costs for three different scenarios based on the conservative, mid-, and advanced cost scenarios from the 2024 NLR Transportation ATB for PEM fuel cells and the 2024 NLR Electricity ATB for power electronics. Figure 5 shows the future PEM fuel cell module cost, and Figure 6 shows the future inverter cost, as published in the 2024 NLR ATB. For fuel cells, the mid scenario is based on business-as-usual regulatory and market environments, the conservative scenario assumes technology cost improves at rates based on the Annual Energy Outlook (U.S. Energy Information Administration 2023a), and the Advanced scenario occurs with breakthroughs, increased research and development, and other beneficial market conditions (National Laboratory of the Rockies 2024). For inverters, the mid scenario is based on research and development investments continuing at current levels and achieving industry roadmaps but without significant innovations or breakthroughs. The conservative inverter scenario assumes reduced levels of research and development and minimal technology advancement, while the advanced scenario assumes increased research and development investment that generates substantial innovation (National Laboratory of the Rockies 2024). We assume the future transformer cost is constant at \$38.84/kW.

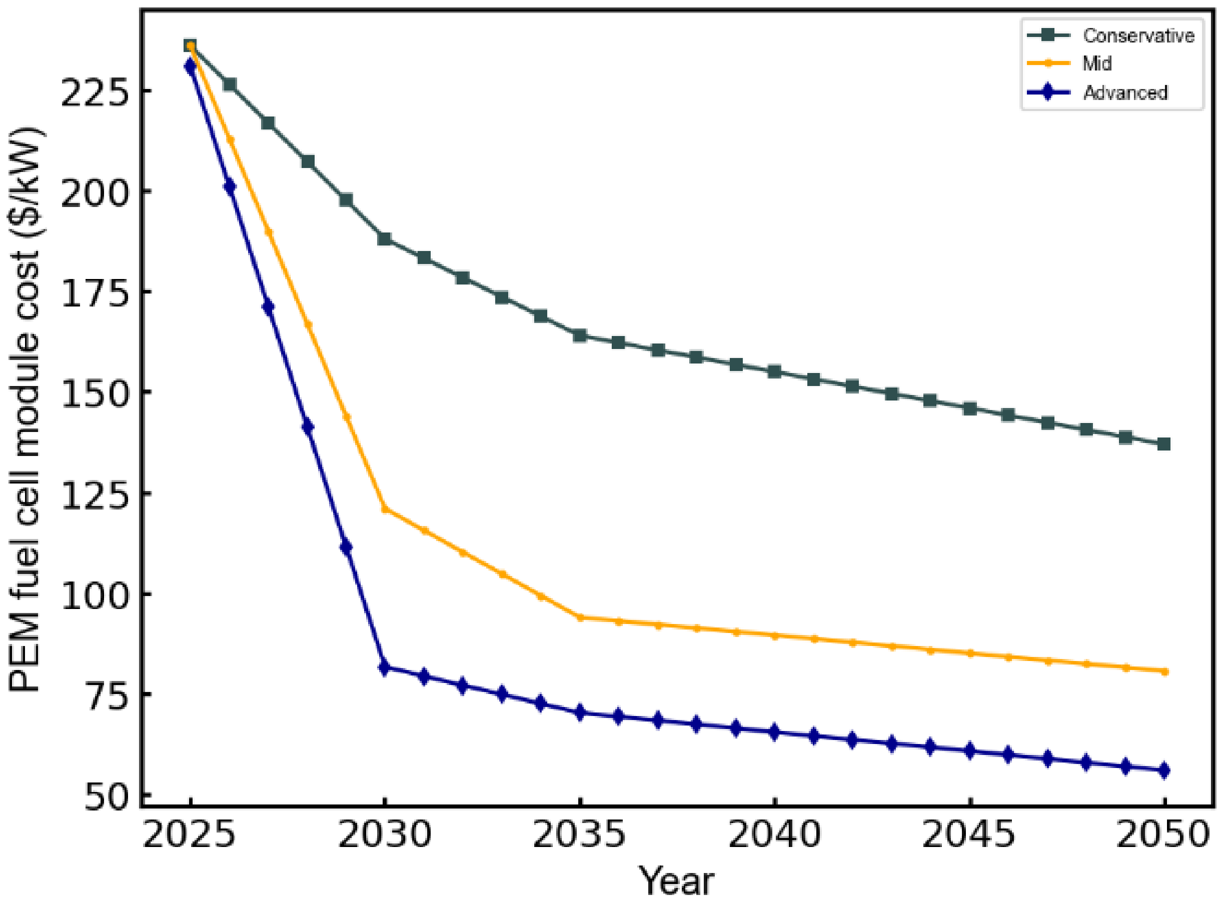

Figure 5. Future PEM fuel cell module cost for each scenario

The yellow line and dots represent the Mid-cost case, the blue line and diamonds represent the Advanced or Low-cost case, and the green line and squares represent the Conservative or High-cost case, as taken from the 2024 Transportation ATB.

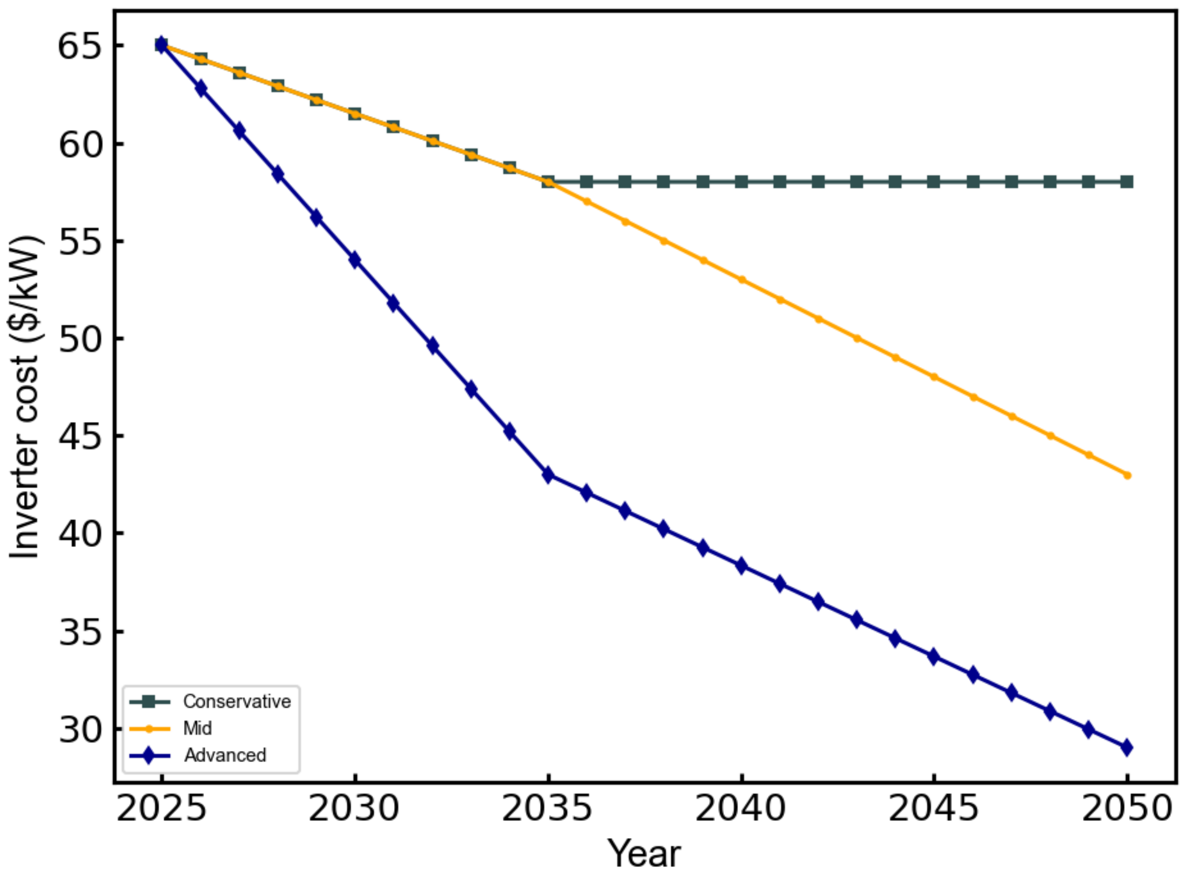

Figure 6. Future inverter cost for each scenario

The yellow line and dots represent the Mid-cost case, the blue line and diamonds represent the Advanced or Low-cost case, and the green line and squares represent the Conservative or High-cost case, as taken from the 2024 Electricity ATB.

Note, in this study, we do not assume any changes in component performance, volumetric power density, overall design, or manufacturing volumes over time, so the cost trajectories shown for PEM fuel cells and inverters constitute the entirety of changes to model inputs for future system total overnight cost estimation. The design and layout of the power plant remain the same regardless of year or scenario. Improvements in component performance, power density, or design could lead to other balance of plant cost reductions that impact total overnight cost. These potential effects are not captured in the present analysis, and therefore the results herein might overstate future stationary PEM fuel cell total overnight cost.

1.3 Balance-of-Plant Sizing and Material Costing

This study separates BOP costs into labor, material, and equipment costs for each line item within the structural and electrical BOP categories in a manner similar to that of Ramasamy et al. 2023. Each line item is assigned a "job quantity" that indicates how many units of that line item must be installed; for example, the job quantity for piping is the number of meters of piping required for the facility. The modeling framework then applies the cost per unit of job quantity for labor, material, and equipment costs for each line-item cost. The rest of this section details how this study determines fuel-cell-specific line-item cost job quantities and material costs; the following section details labor costs associated with installation of this BOP equipment.

1.3.1 Hydrogen Piping

Hydrogen is distributed throughout the FCBs via underground piping. We assume one large pipe brings hydrogen into the building, from which it is then distributed into one "medium"-sized pipe for each row of fuel cells. A smaller pipe then carries hydrogen up each column for consumption by the fuel cell modules.

We employ hydraulic calculations to calculate the diameter of each pipeline based on the hydrogen flow rate and the inlet and outlet pressures of each pipe, and use American Society of Mechanical Engineers (ASME) B31.12 (American Society of Mechanical Engineers 2023) to determine the schedule of each pipe assuming that they are constructed with 304 stainless steel. Knowing the schedule and diameter allows calculation of the total pipe mass, which subsequently allows calculation of pipe material cost per meter of pipe length. We assume hydrogen enters the FCB at 4 bar-g and it must be delivered to the fuel cell modules at 0.9 bar-g. We assume the pressure drop in the small pipes is 0.1 bar but iterate on the intermediate pressure between the large pipe that carries hydrogen into the FCBs and the medium pipes that distribute hydrogen above each row of fuel cell modules to determine the diameter of both medium and large pipes that results in the lowest total pipe material costs. We conservatively estimate stainless steel 304 pipes cost $20/kg based on actual pipe costs listed on Metals Depot (Metals Depot 2025). Note actual systems might operate with higher plant hydrogen inlet pressure and with higher fuel cell module operating pressure. This could allow for smaller-diameter pipes, though they would have to be thicker. The trade-off in cost is not immediately clear, but as Section 3 demonstrates, the decision will not significantly impact total plant cost and should of course be made based on engineering requirements and safety considerations.

1.3.2 Air Ducting and Water Piping

PEM fuel cells produce water that exits the fuel cell in the waste air stream. This study assumes that air ducts are composed of high-temperature duct hose (McMaster-Carr 2024c) placed in the space between back-to-back fuel cell rows and that they route air directly up and through the roof. Based on the air flow for each fuel cell module from the process modeling results and the assumption that the air duct is high pressure (7 inches water column) with a duct velocity limit of 4,000 feet per minute (or 20.32 meters per second) (Bhatia 2024), we estimate a duct diameter of 10 inches (0.254 m) for each pair of fuel cell columns. Because water vapor could condense out of the air inside of the air duct, we assume the bottom of each air duct is connected to a condensate trap that drains into a 2-inch diameter stainless steel pipe buried under the FCB floor with a gradient to carry condensed water out of the building. Hydraulic calculations suggest 2 inches should be more than enough to carry condensate even if all exhaust water condenses within the air ducts, which is unlikely to happen.

1.3.3 Coolant Piping

Coolant pipe sizing follows the same methodology as water and hydrogen piping but is slightly more complicated because it spans both the FCBs and the coolant radiator pad. We assume a pump located at the hot-side inlet of the coolant radiator pad circulates coolant throughout the loop, and we separate the different segments of this loop into six distinct pipes with unique flow rates. Table 6 provides descriptions of these pipes and assumptions regarding their pressure drops and flow rates. We also assume the coolant experiences a 0.2 bar pressure drop through both the fuel cell modules and the coolant radiators. We use ASME B31.1 to determine the schedule of each pipe.

Table 6. Coolant Pipe Descriptions, Flow Rate, and Pressure Drop Assumptions

Pipeline Description	Flow Rate Assumptions	Pressure Drop Assumptions
Large pipes carrying fuel cell coolant between the fuel cell-inverter-MVT pad and the coolant radiator pad	Full coolant flow rate	0.3 bar
Medium pipe carrying coolant under each row of fuel cell modules	Coolant to serve one row of fuel cell modules	0.3 bar
Small pipe carrying coolant in between fuel cell modules and the underground medium coolant pipes	Coolant to serve one vertical column of fuel cell modules	0.02 bar
Medium pipe carrying coolant along one row of coolant radiators	Full coolant flow rate divided by the number of coolant radiator rows	0.3 bar
Small pipes carrying coolant between each radiator and the medium pipes that distribute and/or collect coolant in each radiator row	Full coolant flow rate divided by total number of coolant radiators	0.05 bar

1.3.4 Electric Cabling and Conduit

There are two distinct regions of cabling within the fuel cell power plant: the low-voltage DC cabling between the fuel cell modules and the inverter/MVT units, and the medium-voltage AC cabling that collects electricity from the inverter/MVTs and delivers it to the high-voltage transformer substation. For both segments, this study employs the National Fire Protection Association 70 National Electric Code (National Fire Protection Association 2023) to select and size cabling and conduit. More specifically, we employ ampacities from Article 310 for the low-voltage DC cabling between fuel cell modules and the inverter/MVTs and ampacities from Article 315 for the medium-voltage AC cabling between the inverter/MVTs and the high-voltage transformer substation. For each length of DC and AC cable, the model selects the minimum cable size that meets the national electric code requirements and assigns costs per unit length for 2-KV wire from (Wire & Cable Your Way 2024b) for DC cabling and for 35-kV power cable from (Wire & Cable Your Way 2024a) for medium-voltage AC cable. Table A-1 provides the precise costs pulled for low-voltage and medium-voltage cable at the time that this analysis was conducted. The model then determines the size of conduit and number of conduit runs for each cable size and assigns cost per unit length based on (Grainger 2024) for liquid-tight galvanized steel conduit with a flame-retardant polyvinyl chloride jacket. Table A-2 provides the precise conduit costs pulled at the time that this study was conducted.

1.3.5 Valves, Fittings, and Instrumentation

A PEM fuel cell plant requires a variety of valves, fittings, flow meters, and thermocouples to allow safe and efficient operation and to facilitate maintenance. Here, we detail our assumptions about the selection and design of these components. Each fuel cell requires a hydrogen manual shutoff valve along with an inlet and outlet coolant shutoff valve to enable fuel cells to be isolated for maintenance. Similar valves will also be necessary for cooling radiators. The hydrogen and coolant line running vertically up the columns of fuel cell modules within the FCBs will each have pressure relief valves at the highest point in the pipes near the top of each column of fuel cells modules. All hydrogen pipes and the small coolant pipes are connected via welded reducing tee connectors and the medium and large coolant pipes are connected to their smaller branches via stub-in welds, which should be sufficient given the low overall pressure of fluids within the system. As mentioned previously, condensate traps are also necessary, and we assume each fuel cell will have a thermocouple mounted to the outlet coolant stream. We assume each fuel cell module and cooling radiator will have flow meters included as part of the equipment package.

Safety equipment considered in this study includes flame detection, combustible gas detection, and early leak detection within each FCB. Consulting with hydrogen safety experts, we deemed active flame detection in the form of infrared-ultraviolet (IR-UV) cameras should be placed at the end of each bank of fuel cell modules. Although the range of IR detection is longer than the length of each bank of fuel cell modules, camera resolution is important to provide rapid response to plumes of a relevant size. For this reason, IR-UV cameras are placed to provide coverage for half the length of a single bank. Because hydrogen is more buoyant than air and very diffusive, sensors with high selectivity for hydrogen should be placed on the ceiling of the fuel cell building above the middle of each bank. Cursory review of the layout suggests two sensors per row of fuel cell modules should be sufficient to provide rapid detection of hydrogen leaks. Ultrasonic leak detectors work by tuning into the characteristic inaudibly high-frequency sounds generated by gas leaks. Such leak sensors provide early detection of leaks anywhere in the system. Cursory assessment estimates one sensor per row of fuel cells would be sufficient for early leak detection. The sensors would be placed in the middle of the fuel cell rows. We assume costs associated with ceiling-placed ventilation for removing any leaked hydrogen are included in the fuel cell building cost. Note the characterization of safety equipment in this report is cursory and does not represent a comprehensive review of hydrogen safety codes and standards. For that purpose, we refer readers to NFPA 2 (National Fire Protection Association 2023), CSA-ANSI FC 1 (Canadian Standards Association/American National Standards Institute 2021), and ASME B31.12 (American Society of Mechanical Engineers 2023). Table 7 and Table 8 provide the means for calculating the total number of each valve, fitting, and sensor, along with the references used for costs, for the FCBs and cooling radiator pad, respectively. Table A-3 and Table A-4 give the precise costs pulled from these references at the time this study was performed.

Table 7. FCB Valve, Fitting, and Instrument Quantities.

Where no value is given, the value is zero.

Component	Number per Fuel Cell Module	Number per Fuel Cell Pod	Number per Fuel Cell Row	Cost Reference
Hydrogen shutoff valve	1			(Assured Automation 2025)
Hydrogen shutoff valve flange	2			(McMaster-Carr 2024e)
Coolant FCB shutoff valve	2			(McMaster-Carr 2024b)
Coolant FCB shutoff valve flange	4			(McMaster-Carr 2024d)
Hydrogen small reducing tee connectors	1			(McMaster-Carr 2024f)
Hydrogen medium reducing tee connectors		6		(McMaster-Carr 2024f)
Hydrogen large reducing tee connectors			1	(McMaster-Carr 2024f)
Coolant FCB small reducing tee connectors	2			(McMaster-Carr 2024f)
Coolant FCB small pipe stub-in weld		12		(McMaster-Carr 2024f)
Coolant FCB Medium Pipe medium pipe stub-in weld			2	(McMaster-Carr 2024f)
Coolant FCB air relief valve		6		(McMaster-Carr 2024a)
Hydrogen FCB pressure relief valve		6		(McMaster-Carr 2025)
Coolant FCB thermocouple	1			(McMaster-Carr 2024g)
IR-UV cameras			4	(Det-Tronics 2025)
Hydrogen sensors			2	(RKI Instruments 2025)
Ultrasonic gas leak detectors			1	(Instrumart 2025)

Table 8. Cooling Radiator Pad Valve, Fitting, and Instrument Quantities

Component	Number per Radiator	Number per Radiator Row	Cost Reference
Coolant radiator shutoff valve	2		(McMaster-Carr 2024b)
Coolant radiator shutoff valve flange	4		(McMaster-Carr 2024d)
Coolant Small Pipe radiator pad small pipe stub-in weld	2		(McMaster-Carr 2024f)
Coolant radiator pad medium pipe stub-in weld		2	(McMaster-Carr 2024f)
Coolant radiator thermocouples	1		(McMaster-Carr 2024g)

1.3.6 Other Miscellaneous Balance-of-Plant Costs

Table 9 provides methodology for sizing and costing various other plant BOP costs, including buildings, concrete foundations, security fencing, site preparation, and so on. The costs of many of these items are taken from Ramasamy et al. (2022). We assume site preparation and the instrumentation and control equipment costs will be similar to those associated with NGCT power plants and take costs for these items from the NLR ATB (National Laboratory of the Rockies 2024). For some costs such as the FCBs, pallet racks, the maintenance and control building, instrumentation and control equipment, and the transformer substation, we apply all installation costs (including labor and equipment) in a single simplified value to the material cost category. Trenches do not have material costs but rather have an equipment cost of $0.21/ft.

Table 9. Miscellaneous Balance-of-Plant Material Cost Quantification Methodology

Cost Category	Job Quantity Description	Material Cost per Job Unit [$]	Cost References
FCBs	Square feet of required floor space	$200/ft^2	(Statistica 2023)
Pallet racks for fuel cell modules	One rack per fuel cell module	$300/pallet	(Speedrack West 2023; Conner and Arif 2023; Cranston 2023)
Maintenance and control building	One per plant	$200/ft^2	(Statistica 2023)
Instrumentation and control	One per plant	$31/kW-AC	(National Laboratory of the Rockies 2024)
Forklift	One per plant	$55,000	(Rout et al. 2022; Conger 2023)
Cooling pad foundation	Square feet of space	$4.2/ft^2	(Ramasamy et al. 2022)
Trenches	Total combined length of coolant piping external to the FCBs and medium-voltage AC cabling	0	(Ramasamy et al. 2022)
Site preparation	One per plant	$61/kW-AC	(National Laboratory of the Rockies 2024)
Security fencing	Perimeter of power plant	$24.5/ft	(Ramasamy et al. 2022)
Junction/combiner boxes	One for each inverter/MVT	$1,100/inverter/MVT	(Ramasamy et al. 2022)
Combining switchgears	One per plant	$160,000	(Ramasamy et al. 2022)
High-voltage transformer substation	One per plant	$42.49/kW-AC	(Ramasamy et al. 2023)

1.4 Balance-of-Plant Labor Costing

This study quantifies labor costs by estimating the number of labor hours required for each task or component installation and then applying hourly labor rates corresponding to the expected distribution of labor type. For tasks shared in common with solar PV plants such as trench digging, cable and conduit laying, and foundation pouring, this study pulls expected labor hours and distributions from Ramasamy et al. (2023). Table A-5 gives these estimates for labor hours, and Table A-6 gives the distribution of those hours for different types of laborers.

For hydrogen- and cooling-related components, this study identifies specific tasks associated with the handling and installation of pipes, valves, flanges, and fittings, and employs the *Estimator's Piping Man-Hour Manual* to estimate the number of labor hours required for each task (Page 1999). Table A-7 gives the page numbers from (Page 1999) for pipe shop and field handling, and Table A-8 and Table A-9 give the labor hour quantification methods and page numbers from Page (1999) as well. For hydrogen-specific components, this study assumes 100% of labor is completed under the labor category of "common laborer." Hourly labor costs for different labor categories are taken from the U.S. Department of Energy 2025, which work out to $33/hr for electricians and $24/hr for construction workers or "common laborers." Note that these are take-home labor rates and not fully burdened; overhead for labor is included in EPC costs. The modeling framework used in this study takes the information in Tables 7 and 8 the Appendix and aggregates it with the plant design to determine total labor costs for each task.

1.5 Indirect and Owner's Costs

Table 10 gives various indirect costs, including EPC, interconnection fees, contingencies, and sales taxes. These parameters are all subject to local variation. For this study, we employ values used by Ramasamy et al. (2022) for sales taxes, which are applied to total material and equipment cost. We estimate grid interconnection fees at $100/kW_{AC}$ to be consistent with common practices for other power production technologies in NLR's 2024 ATB (National Laboratory of the Rockies 2024). We estimate EPC costs at 20% of bare erected cost (which includes all primary equipment, structural and electrical BOP, and installation labor) in accordance with NETL's quality guidelines for energy systems (Theis 2021). We apply total process and project contingencies of 20% of the sum of bare erected cost and EPC for all structures and foundations and 15% for all nonstructural items, which is consistent with total contingency for NGCT plants included in NLR's 2024 ATB (National Laboratory of the Rockies 2024). Contingencies are applied to capture costs that have been shown to be likely to occur even if they cannot be explicitly quantified at the time an estimate is prepared (Theis 2021).

Table 11 gives owner's costs based on the NETL Quality Guidelines for Energy System Studies (Theis 2021). For nonfuel preproduction costs and the 60-day supply of consumables, we assume the cost is the same on a dollar-per-kilowatt basis as that assessed for NGCT plants as part of the 2024 NLR electricity ATB (National Laboratory of the Rockies 2024). The fuel cost is based on an estimated hydrogen fuel price of $1.21/kg, based on an estimate of the cost of hydrogen production via steam methane reforming with average U.S. natural gas prices (Penev 2021) and estimated costs for stimulated geologic hydrogen under optimal conditions with large-scale hydrogen transport (Mathur et al. 2025), and the beginning-of-life estimated efficiency of the fuel cell modules 50.5% on an LHV basis. Financing costs include the cost of securing financing, including fees and closing costs but not including interest accrued during construction (Theis 2021). Note the "Other Owner's Costs" category includes costs such as preliminary feasibility studies, economic development, construction and improvement of infrastructure outside of the site boundary, legal fees, permitting costs, owner's engineering, and owner's contingency (Theis 2021). Land costs assume a rural location and are taken from Ramasamy et al. (2022).

Table 10. Indirect Costs

Cost Category	Value
EPC cost (% of bare erected cost)	20%
Transmission spur line and interconnection fee	$100/kW$_{AC}$
Total process and project contingency (% of bare erected cost + EPC) for structures and foundations	20%
Total process and project contingency (% of bare erected cost + EPC) for all nonstructural items	15%
Sales tax	5.8%

Table 11. Owner's Costs

Cost Category	Value
Preproduction Costs	
6 months all labor	$4.01/kW$_{AC}$
1 month maintenance materials	$4.03/kW$_{AC}$
1 month nonfuel consumables	$0.13/kW$_{AC}$
1 month waste disposal	$0.001/kW$_{AC}$
25% of 1 month's fuel cost at 100% capacity factor	$12.9/kW$_{AC}$
2% of total plant cost	2% of total plant cost
Inventory Capital	
60-day supply of consumables at 100% factor	$0.27/kW$_{AC}$
Spare parts	0.5% of total plant cost
Land acquisition	$4,000/acre
Financing costs	2.7% of total plant cost
Other owner's costs	15% of total plant cost

1.6 Levelized Cost of Electricity Calculation

While total overnight cost is a useful metric for comparing power generation technologies, it does not paint the full picture. Fuel and operating costs should also be considered, and the levelized cost of electricity (LCOE) provides a convenient metric for aggregating various fuel and operating costs, defined as the net present value of all capital, operating, and financial costs divided by the system lifetime electricity sales (Hunter et al. 2021). In this analysis, we use the NLR model ProFAST (Kee and Penev 2024) to calculate the LCOE for PEM fuel cell power plants and compare it to that of NGCT power plants. Table 12 provides assumptions used in the LCOE calculation.

Table 12. LCOE calculation parameters (all costs in 2022 USD)

Cost Category	PEM Fuel Cell Plant	NGCT	PEMFC Reference	NGCT Reference
Total Overnight Cost ($/kW)	1,352	$1,500	See Section 3	GridLab et al. (2025)
Heat Rate (BTU/kWh)	8,461	9,142	(Huya-Kouadio and James 2023)	Sargent & Lundy (2023)
Fuel Cost ($/MMBTU)	3.73 – 22.4	4.52	(Penev 2021; Mathur et al. 2025)	(U.S. Energy Information Administration 2023a)
Capacity factor (%)	2 – 10		(U.S. Energy Information Administration 2024a; 2024b)	
Fixed Operations and Maintenance Cost ($/kW-yr)	7.03		(Sargent & Lundy 2023)	
Variable Operating and Maintenance Cost ($/MWh)	1.27		(Sargent & Lundy 2023)	
Plant Life (years)	40		(Sargent & Lundy 2023)	
PEM Fuel Cell Stack Durability (hours)	25,000	-	Kleen and Gibbons (2024)	
PEM Fuel Cell Stack Refurbishment Cost Fraction (-)	0.63	-	Kleen and Gibbons (2024)	
Property Tax and Insurance (% of TOC/year)	1.5		Penev et al. (2024)	
Inflation Rate (%)	0		Penev et al. (2024)	
Construction Period (years)	3		Penev et al. (2024)	
Total Income Tax Rate (%)	25.7		Penev et al. (2024)	
Capital Gains Tax Rate (%)	15		Penev et al. (2024)	
Leverage After Tax Nominal Discount Rate (%)	10.2		Penev et al. (2024)	
Debit Equity Ratio of Initial Financing	0.62		Penev et al. 2024)	
Debt Interest Rate (%)	4.4		Penev et al. (2024)	
Months of Cash on Hand	3		Penev et al. (2024)	

For simple cycle NGCTs, we derive total overnight cost from GridLab et al. (2025) for plants coming into operation in 2029 and take heat rate, fixed operations and maintenance costs, and variable operations and maintenance costs from Sargent & Lundy (2023). The PEM fuel cell plant heat rate is based on an average efficiency of 47.6% LHV calculated from the beginning-of-life and end-of-life efficiencies of 44.7% LHV and 50.5% LHV, respectively. We assume that PEM fuel cell plants will have the same fixed and variable operating expenses as industrial frame

NGCTs. The range of capacity factors considered covers the majority (>75%) of capacity factors achieved by combustion turbine plants between 2014 and 2023 (U.S. Energy Information Administration 2024a; 2024b). The assumed PEM fuel cell durability and refurbishment cost fraction are from Kleen and Gibbons (2024). We take the rest of the financial parameters from Penev et al. (2024) for analysis performed on real rather than a nominal basis.

1.7 Model Implementation

This study employs a Python-based framework to design the PEM fuel cell plant, quantify line-item costs, and aggregate costs into total overnight cost. A geometric module takes component-level inputs such as component rated power, dimensions, and spacing requirements and lays out the plant based on the qualitative diagram shown in Figure 2. The geometric module then uses this layout to determine various job quantities such as pipe and cable lengths, FCB floor space, and total plant acreage and perimeter length. The various costs listed in Table 1 are then calculated using a financial framework similar to that employed by Ramasamy et al. (2022). Figure 7 shows a flow diagram of the framework of the model, which is named “Fuel Cell Plant Layout and Cost Estimation Resource”, or “FC-PLACER.”. FC-PLACER is open source and available at www.github.com/NatLabRockies/FC-PLACER.

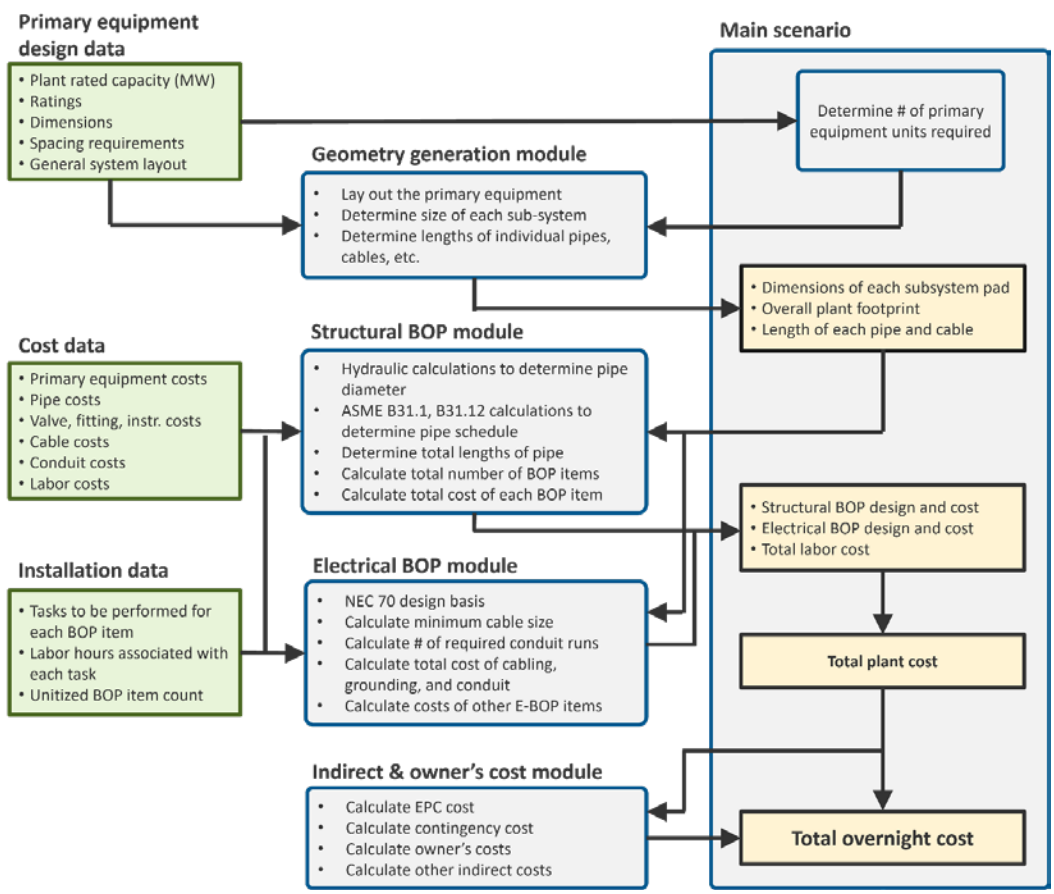

Figure 7. Flow diagram of FC-PLACER

Green boxes represent inputs, gray boxes represent modules or functions, and yellow boxes represent module or model outputs.

2 Results

This section presents the results of implementing the modeling infrastructure and methodology described previously. It is separated into two subsections. The first subsection presents detailed design and cost results for the system using current primary equipment costs. The second subsection presents estimations of future cost through 2050 when applying the different future cost scenarios described in Section 2.2.6.

2.1 Total Overnight Cost with Current Equipment Costs

Figure 8 shows a top-down schematic of the 100-MW PEM fuel cell power plant, illustrating the locations and footprints of the different plant subsystems. Table 13 provides the total area consumed by each subsystem, along with the total lengths for different sizes of pipes and cables. The total plant area is 15,945 square meters, or approximately 4 acres. Assuming larger PEM fuel cell plants are designed with the same power density, their total footprint would likely scale linearly with total capacity. Where land is limited or expensive, developers could also build structures to enable them to stack fuel cells, power electronics, and cooling radiators in a vertical manner with multiple floors to save space, similar to the layout of the Hanwha 50 MW phosphoric acid fuel cell plant in South Korea (Hanwha 2020). Such an approach is beyond the scope of this study.

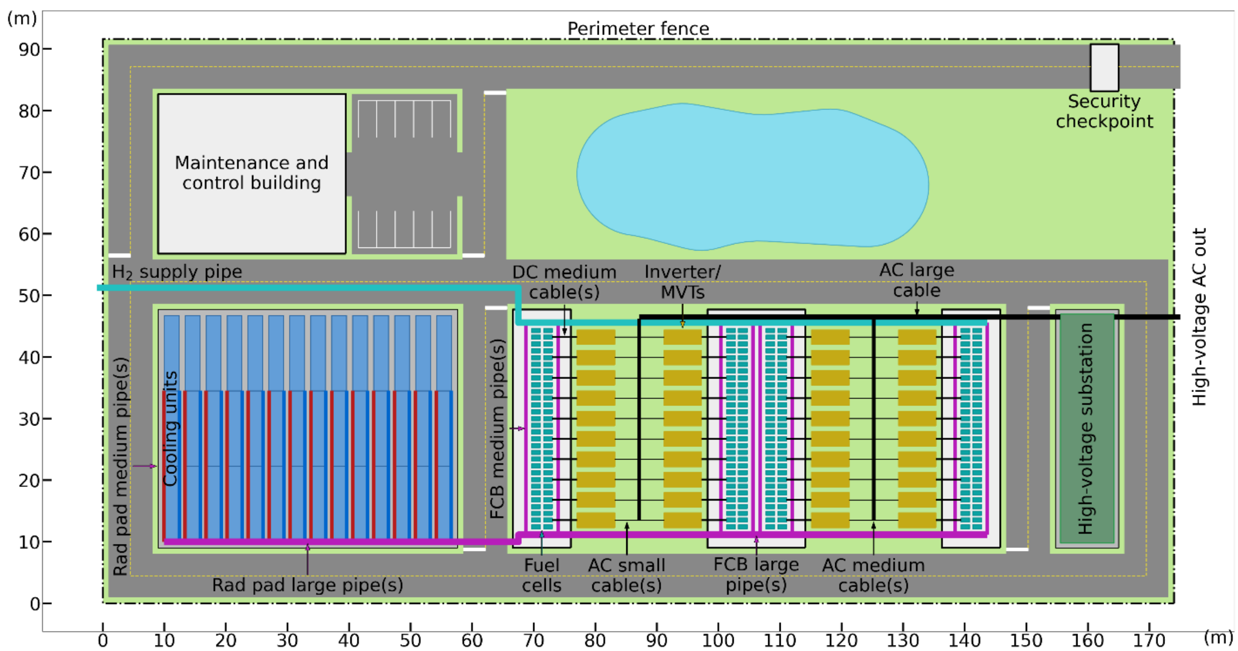

Figure 8. Schematic of the 100-MW PEM fuel cell plant layout, as it would be seen from above, with *x* and *y* dimensions in units of meters

The gray perimeter around each pad represents two-lane roads to ensure adequate access to equipment for installation and maintenance, and the light green shades represent grass or gravel areas that do not necessarily require structural foundations.

Table 13. Plant-Wide Footprint and Measurements

Property	Value
FCB area (m^2)	1,346
Control building area (m^2)	790
Cooling pad area (m^2)	1,882
Total plant area (m^2)	15,945
AC cable (large) total length (m)	80
AC cable (medium) total length (m)	66
AC cable (small) total length (m)	161
DC cable (medium) total length (m)	162
DC cable (small) total length (m)	816
Large pipe for hydrogen supply to system total length (m)	151
Large pipe for coolant total length (m)	268
Cooling pad medium pipe total length (m)	687
FCB medium hydrogen pipe total length (m)	276
FCB medium coolant pipe length total length (m)	551
Cooling pad small pipe total length (m)	137
FCB small coolant pipe total length (m)	913
FCB small hydrogen pipe total length (m)	457
FCB very small coolant pipe total length (m)	960
FCB very small hydrogen pipe total length (m)	480

Table 14 gives nominal diameter (in mm), schedule, cost per unit meter, and total plant-wide length for each type of pipe installed in the plant. As described in Section 2.3, the model determines pipe diameter using hydraulic calculations and determines pipe schedule based on the material (in this case, stainless steel 304), the pressure experienced by the pipe, and the relevant ASME B.31 guidelines. As a result of the low pressure of the hydrogen and coolant systems, all pipes are either schedule S5S or S10. Note exhaust air is routed through ducts rather than pipes and therefore do not have assigned schedules. Pipe cost is based on the total mass of the pipe. Larger pipes cost more per unit length, but there tends to be more total length for smaller pipes. The largest pipes nonetheless cost the most overall because of the higher per unit length expense of larger-diameter pipes.

Table 14. Pipe Design Specifications

Pipe	Pipe Nominal Diameter	Pipe Schedule	Pipe Cost ($/m)	Total Pipe Length (m)	Total Pipe Material Cost ($)
Hydrogen pipe (large)	150	S 5S	226	151	34,101
Hydrogen pipe (medium)	50	S 5S	48	276	13,171
Hydrogen pipe (small)	10	S 5S	10	457	4,458
Hydrogen pipe (very small)	8	S 5S	8	480	3,672
Air pipe (small)	50	-	48	480	22,907
Water pipe (medium)	50	S 5S	48	276	13,171
Air duct (large)	250	-	8.0	468	3,726
Coolant cold (large)	700	S 10	2,745	132	363,531
Coolant FCB (medium)	250	S 5S	452	551	249,133
Coolant FCB (small)	50	S 5S	48	913	43,571
Coolant FCB (very small)	15	S 5S	16	960	15,372
Coolant warm (large)	700	S 10	2,745	132	363,531
Coolant radiator pad (medium)	150	S 5S	226	687	155,152
Coolant radiator pad (small)	100	S 5S	117	137	15,976

Table 15 gives the quantity, associated pipe size, cost per unit, and total cost for each valve, fitting, and instrument installed in the plant. Hydrogen and fuel cell coolant shutoff valves and their flanges add up to a significant amount of cost as a result of the high number of these components required. Reducing tee connectors and safety equipment, although not individually expensive, combine to add a notable amount of cost. Overall, the material costs of valves, fittings, and safety equipment add up to approximately $28/kW.

Table 15. Valve, Fitting, and Instrumentation Quantity and Costs

Component	Count	Pipe Nominal Diameter	Cost per Unit ($)	Total Component Cost ($)
Manual fuel cell module hydrogen isolation valve flange	1,920	8	44	83,539
Manual fuel cell module coolant isolation valve flange	3,840	50	126	483,034
Manual fuel cell module hydrogen isolation valve	960	8	241	231,360
Manual fuel cell module coolant isolation valve	1,920	50	608	1,166,650
Hydrogen small reducing tee connectors	960	10	45	42,720
Coolant FCB small reducing tee connectors	1,920	50	50	96,346
Coolant FCB air relief valve	240	-	300	72,000
Hydrogen FCB pressure relief valve	240	50	300	72,000
Hydrogen medium reducing tee connectors	240	50	50	12,043
Coolant FCB small pipe stub-in weld*	480	50	0	0
Hydrogen large reducing tee connectors	4	150	335	1,340
Coolant FCB medium pipe stub-in weld*	8	250	0	0
Coolant FCB thermocouple	960	-	95	91,200
FCB IR-UV camera	8	-	6,181	98,896
Hydrogen sensors	8	-	1,830	14,640
Ultrasonic gas leak detectors	8	-	30,000	120,000
Coolant radiator pad shutoff valve flange	168	100	314.5	52,841
Coolant radiator pad small pipe stub-in weld*	84	100	0	0
Coolant radiator pad shutoff valve	84	100	1,753.5	147,296
Coolant radiator pad medium pipe stub-in weld*	28	150	0	0
Coolant radiator pad thermocouple	42	100	95.0	3,990

*Stub-in welds have no material cost but DO have labor costs.

Table 16 provides electric cable sizes, quantity, length, and cost, and Table 17 provides the same for conduit. Note cable gauge, quantity, and cost are the same for both power and DC ground cables, and only DC cables and grounding use conduit because the cable selected for medium-voltage AC lines is intended to be directly buried. We assume AC ground cables are negligible because of their buried nature (DC cables, on the other hand, must reach up to the top of each column of fuel cell modules). Overall, cable and grounding costs do not contribute significantly to BOP costs because the plant was designed to minimize low-voltage, high-current DC cable lengths. Conduit costs are also relatively low.

Table 16. Electric Cable and Ground Design Specifications

Cable/ground	Cable Gauge/ kcmil	No. of Cables	Total Cable Cost ($/m)	Total Cable Length (m)	Total Cable Cost ($)
DC small	300	1	12	816	9,531
DC medium	750	7	107	162	17,375
AC small	1/0	1	44	161	7,083
AC medium	750	3	503	66	33,201
AC large	750	6	1,006	88	88,537

Table 17. Electric Cable and Ground Conduit Design Specifications

Cable/Ground	Conduit Trade Size (inch)	No. of Conduit Runs	Total Conduit Cost ($/m)	Total Conduit Length (m)	Total Conduit Cost ($)
DC small	0.75	1	26	816	21,417
DC medium	3	3	224	162	36,221

Table 18 and Figure 9 provide resulting costs for a 100-MW PEM fuel cell plant with current technology. Most of the cost is wrapped up in primary process equipment, which is appropriate considering the fuel cell modules are the least technologically mature component in the system. Structural BOP costs total approximately $153/kW, most of which is associated with the building that houses the fuel cells and inverter/MVTs, pipe, valves, fittings, instrumentation, and site preparation. Site preparation and the fuel cell building costs are particularly significant at $61/kW and $52/kW, respectively. Electrical BOP costs total $77/kW, most of which is associated with the on-site high-voltage transformer substation and instrumentation and controls. Locating the inverter/MVT units close to the fuel cells helps to minimize cabling, grounding, and conduit costs.

Indirect costs add up to $430/kW. Costs associated with transmission to the nearest grid interconnection point and the grid interconnection fee account for $100/kW of the indirect costs. Installation labor and equipment contribute $15/kW, whereas contingency, sales tax, and EPC all contribute significantly to total indirect costs.

The plant total overnight cost sums to $1,352/kW, which is within the range of gas combustion turbine power plants as reported by the U.S. in 2023 (U.S. Energy Information Administration 2023b), and much lower than gas turbine plant costs that have recently been reported as a result of increased demand for gas power (Anderson 2025). This is noteworthy because it suggests hydrogen PEM fuel cell plants, if constructed at scale with current technology, could compete with current grid-peaking power plants.

Table 18. Costs by Category for a 100-MW PEM Fuel Cell Plant With Current Technology

	Total Cost ($2022)	Total Cost ($2022/kW)
Primary Equipment		
Fuel cell systems	27,199,000	271.99
Inverter/MVT	12,149,280	121.49
Cooling	7,770,000	77.70
Total primary equipment cost	**47,118,280**	**471.18**
Structural BOP		
FCBs	3,174,242	31.7
Cooling pad foundation	93,191	0.93
Maintenance and control building and forklift	1,755,000	17.55
Site prep and surveying	6,100,000	61.00
Piping	1,301,472	13.01
Valves, fittings, and instr.	2,789,886	27.90
Security fencing	44,469	0.44
Total structural BOP cost	**15,258,260**	**152.58**
Electrical BOP		
Cabling	163,765	1.64
Grounding	26,905	0.27
Conduit	115,278	1.15
Combiner boxes and switchgear	18,667	0.19
On-site substation	4,249,000	42.49
Instrumentation and control	3,100,000	31.00
Total electrical BOP cost	**7,673,616**	**76.74**
Indirect Costs		
Install labor and equipment	1,537,343	15.37
Transmission and interconnection	10,000,000	100.00
Contingency	13,069,284	130.69
Sales tax	14,317,500	143.17
EPC	14,924,665	149.25
Total indirect cost	**42,987,949**	**429.88**
Owner's Costs		
Preproduction	4,091,290	40.91
Inventory capital	521,530	5.22
Land	15,760	0.16
Financing	2,672,306	26.72
Other (feasibility studies, permitting, legal, etc.)	14,846,142	148.46
Total owner's costs	**22,150,493**	**221.50**
Total overnight cost	**135,208,401**	**1,352.08**

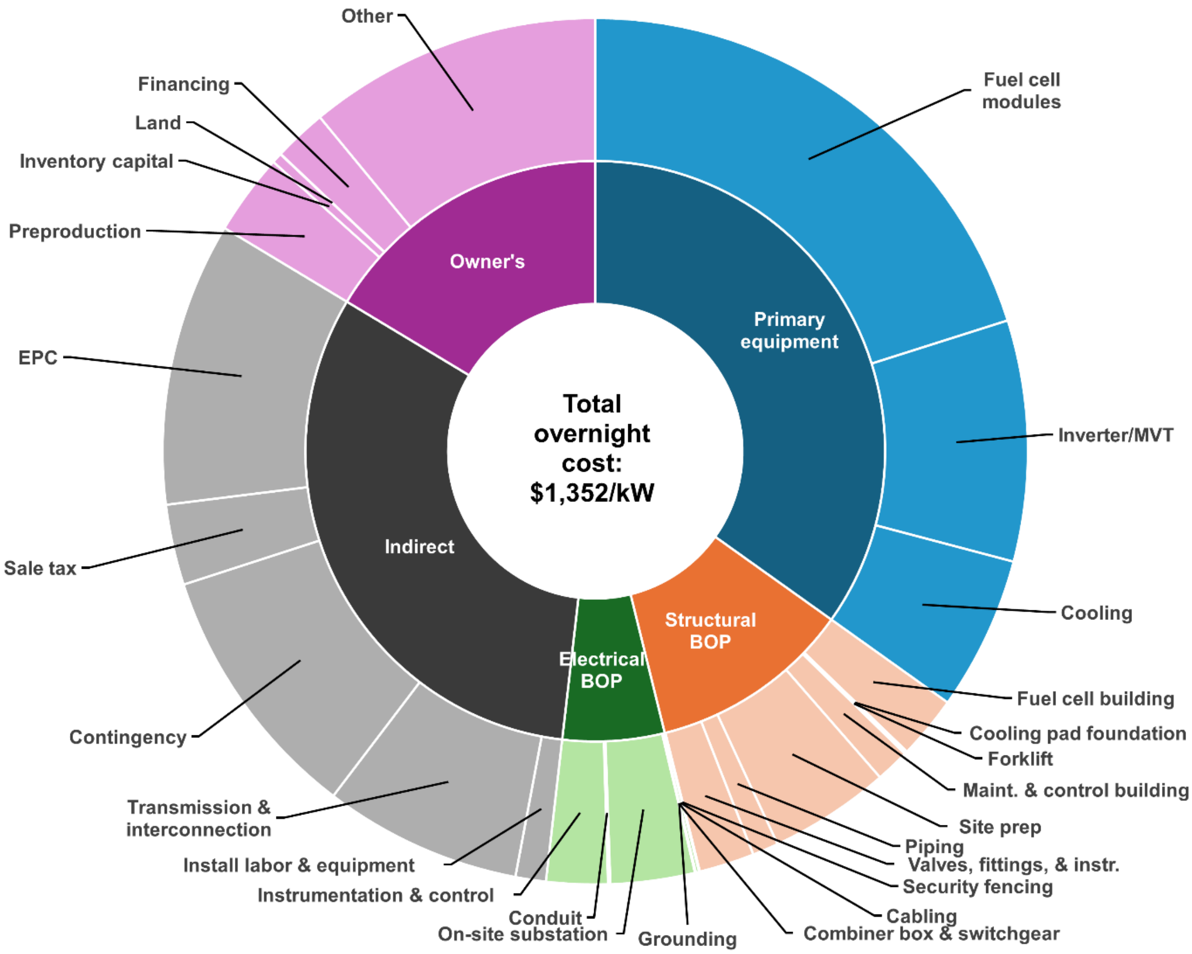

Figure 9. Cost breakdown by category for a 100-MW PEM fuel cell plant with current technology

Note that several sub-categories, including the cooling pad foundation, forklift, security fencing, cabling, combiner box & switchgear, and grounding are too small to be individually identifiable.

2.2 Total Overnight Cost with Potential Future Equipment Costs

Figure 10 shows the total PEM fuel cell system cost from 2025 (considered the "current" year in this analysis) through 2050 when applying future primary equipment costs for PEM fuel cell modules and inverters. The cost trajectories generally follow those of PEM fuel cell modules as shown in Figure 5. In the mid-deployment scenario, the total overnight cost reduces to $1,001/kW in 2050, with the low- and high-cost scenarios resulting in a total overnight cost spread from $924/kW to $1,142/kW. These scenarios all fall within the range of costs for gas combustion turbines as published in 2023 by the U.S. Energy Information Administration (2023b), but are much lower than estimates of recent natural gas turbine costs elevated by increased demand (Anderson 2025).

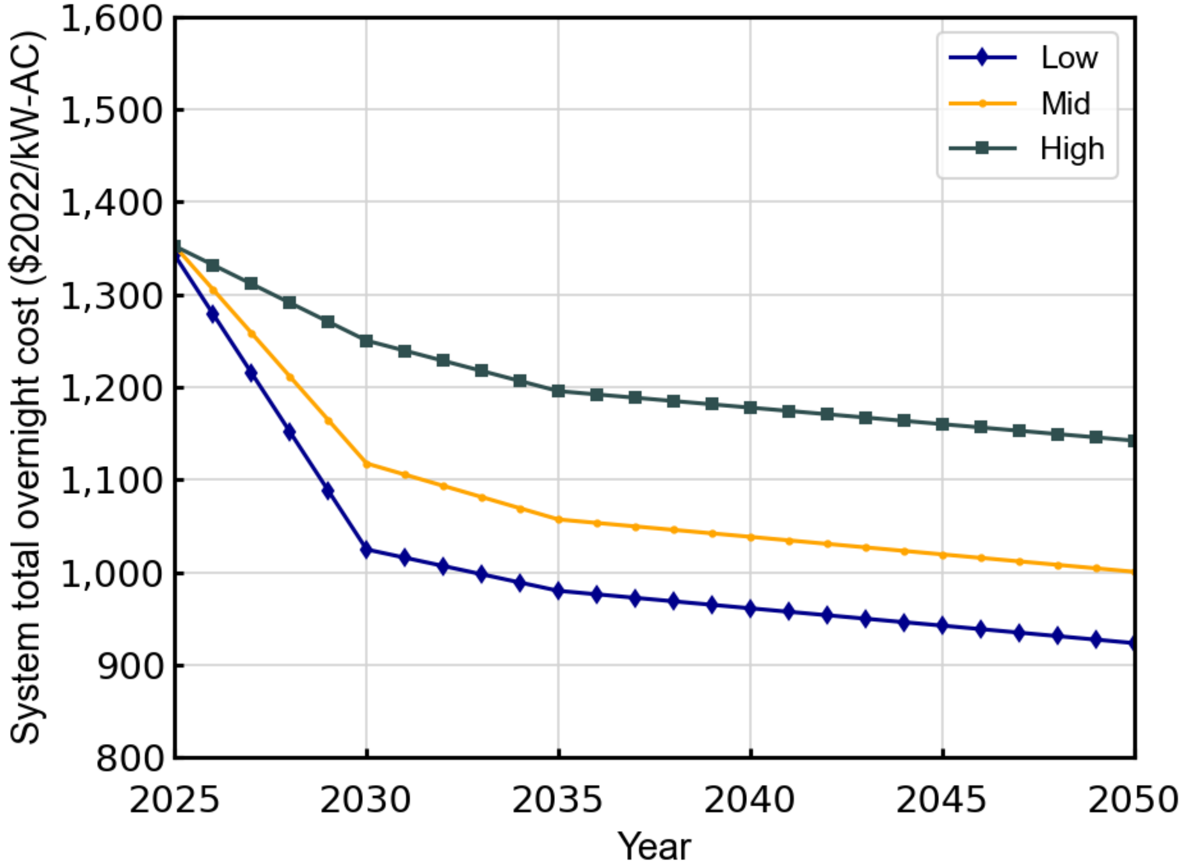

Figure 10. Total PEM fuel cell system installed costs in the future for three different scenarios

The “Low”, “Mid”, and “High” cost scenarios correspond to “Advanced”, “Mid”, and “Conservative” cost cases for PEM fuel cells and inverters from the NLR 2024 ATB.

Figure 11 shows the PEM fuel cell system total overnight cost breakdown over time for the mid-cost scenario. Most of the cost reduction comes from a reduction in PEM fuel cell module costs (Figure 5) with a smaller contribution from reductions in inverter costs (Figure 6). Other costs that are dependent on total plant cost such as contingency, sales tax, and EPC also reduce by a small amount. Note we have not applied cost reductions to any costs except primary equipment (excluding the cooling and transformers). It is possible costs such as installation labor and equipment and permitting could reduce with technology learning, and structural and electrical BOP costs could reduce as fuel cells, inverters, and transformers achieve higher power density. Bulk purchase of structural BOP components such as valves and fittings from vendors that sell to engineering and construction firms, rather than to the public, could also reduce costs. Identifying those cost reductions, however, is out of the scope of this study. Figure A-1 and Figure A-2 show the total overnight cost breakdown over time for the low- and high-cost scenarios, respectively.

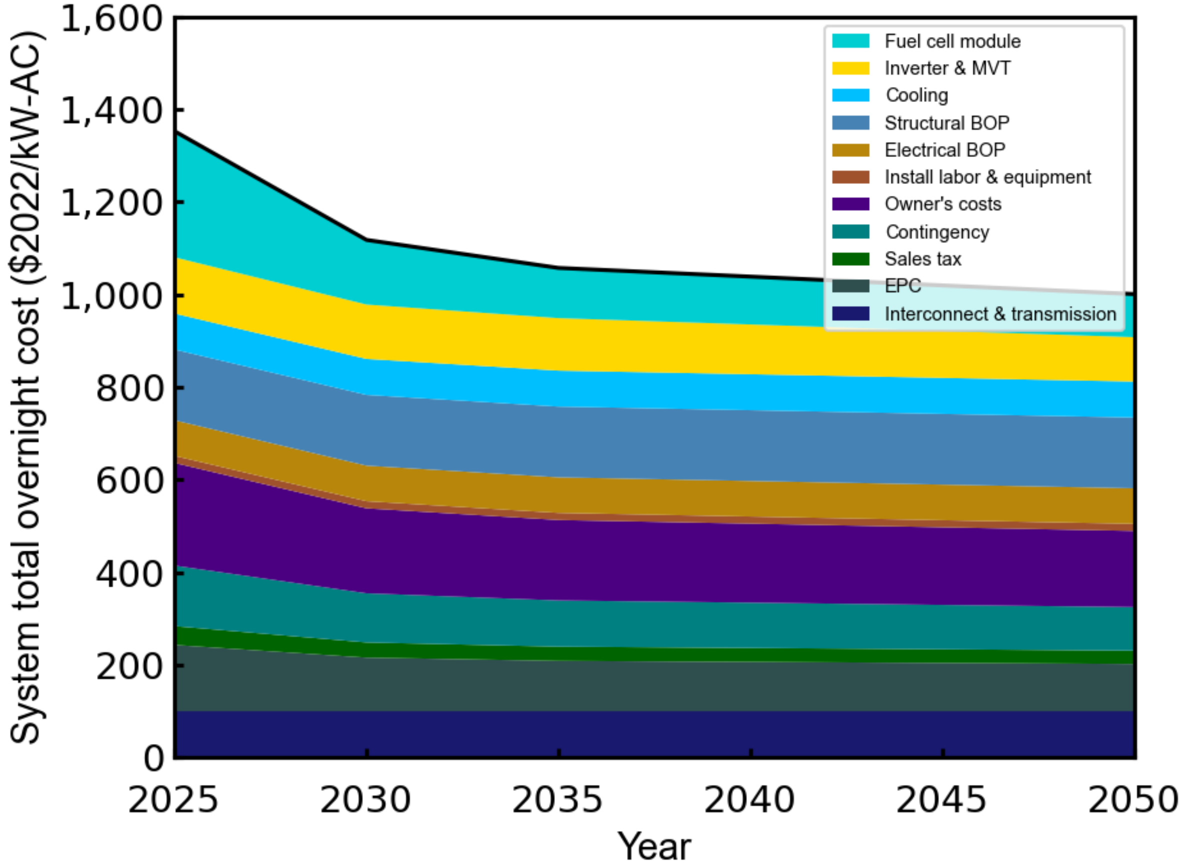

Figure 11. PEM fuel cell system total overnight cost breakdown for the mid-cost scenario

Figure 12 shows the LCOE of NGCT plants and PEM fuel cell plants with 2025 total overnight cost as a function of capacity factor from 2% to 10%. Here we see that with a fuel price of $1.21/kg ($9/MMBTU), PEM fuel cell plants can achieve lower LCOE than NGCT plants for capacity factors up to approximately 5.5%. The difference in LCOE is small relative to the overall magnitude, however. This occurs partly because the differences in fuel prices and capital costs of PEM fuel cell plants and NGCT plants are not dramatic, but also because at low capacity factors, small changes in capacity factor have a significant effect on LCOE.

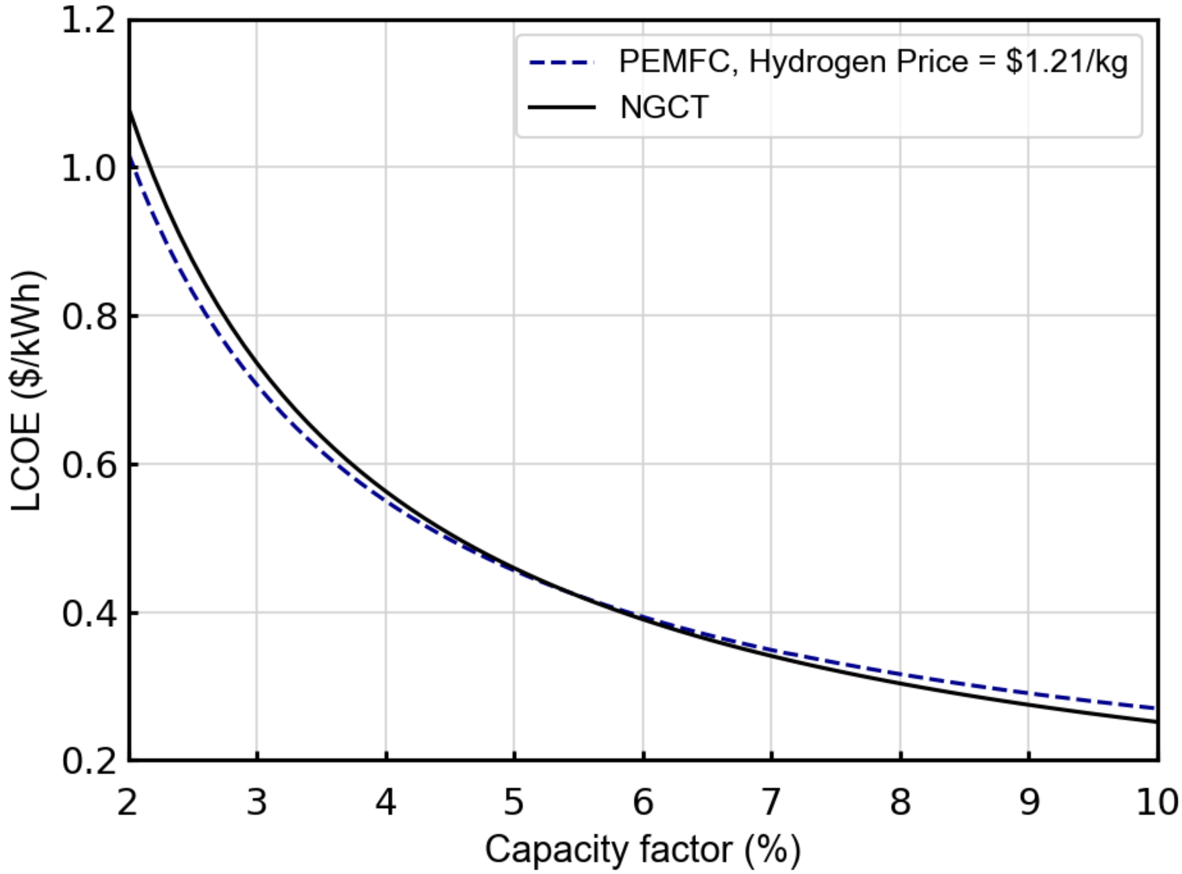

Figure 12. LCOE of NGCT plants and PEM fuel cell plants with 2025 total overnight cost as a function of capacity factor

The PEM fuel cell plant LCOE curve assumes a hydrogen price of $1.21/kg ($9/MMBTU), which is the price estimated based on large-scale production via steam methane reforming (Penev 2021). The NGCT plant LCOE curve assumes a weighted U.S. average natural gas price of $4.52/MMBTU over the plant's life (U.S. Energy Information Administration 2023a).

Figure 13 shows a contour plot of the difference between PEM fuel cell plant LCOE and NGCT plant LCOE, expressed as a percentage, as a function of capacity factor and (for PEM fuel cell plants) as a function of hydrogen price. This figure demonstrates that hydrogen price is inversely related to the capacity factor at which NGCTs achieve lower LCOE. This occurs because fuel price is a larger driver of LCOE at higher capacity factors, so PEM fuel cells must have access to lower cost hydrogen if they are to compete at higher capacity factors. Conversely, this plot indicates that for peaking power plants with very low capacity factor, PEM fuel cells can afford to purchase higher cost hydrogen and still be competitive. Figure 13 also demonstrates the magnitude of the impact of hydrogen price on PEM fuel cell plant competitiveness. At a capacity factor of 3.5%, for example, PEM fuel cells are competitive with hydrogen prices at or below $1.5/kg ($11.2/MMBTU); if that price increases or decreases by $0.5/kg ($3.7/MMBTU), however, then PEM fuel cell LCOE only increases or decrease by approximately 5% relative to NGCT LCOE.

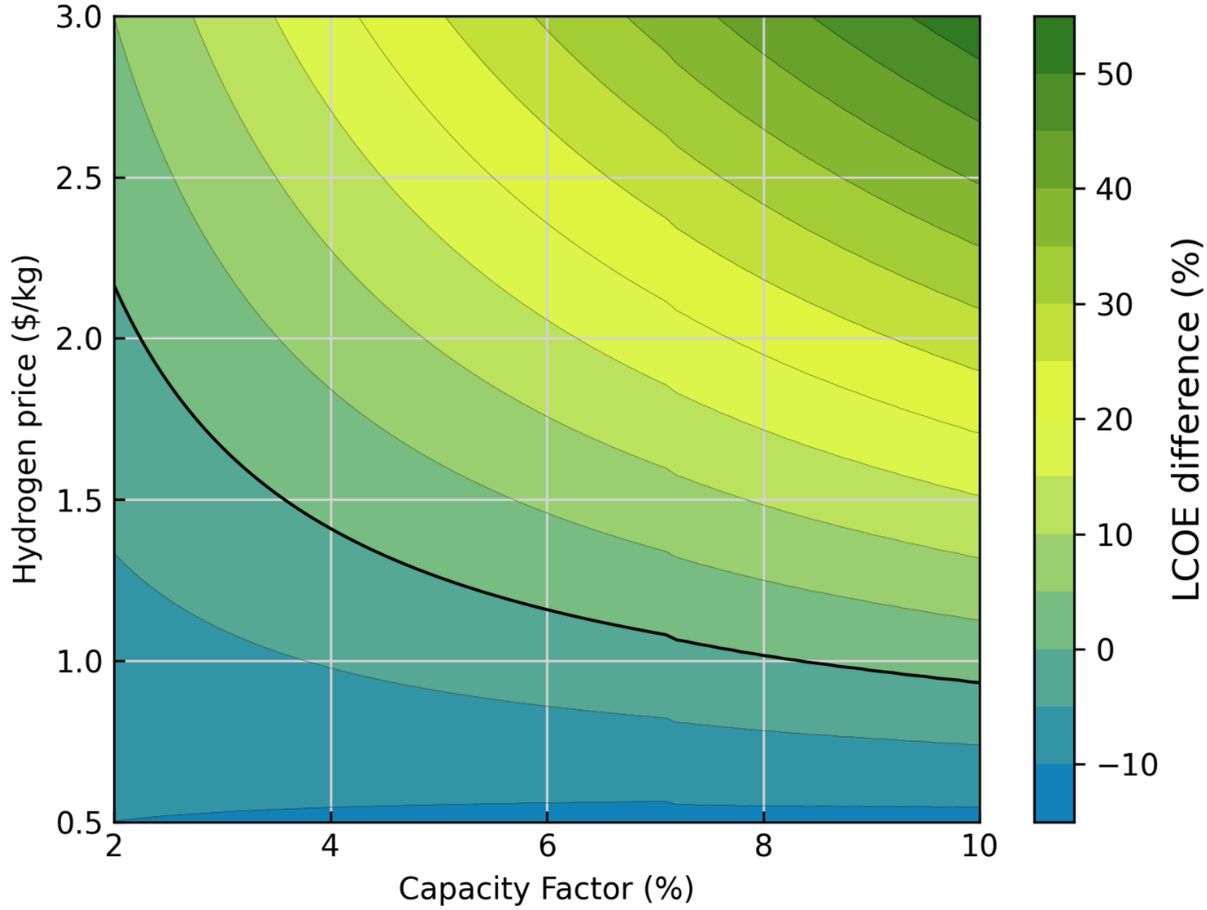

Figure 13. Difference in LCOE between PEM fuel cell plants with 2025 total overnight cost and NGCT plants as a function of capacity factor and hydrogen price

Note that both PEM fuel cell and NGCT LCOE vary with capacity factor, but only PEM fuel cell plant LCOE varies with hydrogen price. Natural gas cost was assumed fixed at $4.52/MMBTU for this figure. The range of hydrogen prices is equivalent to $3.72/MMBTU—$22.37/MMBTU. The small discontinuity at approximately 7% capacity factor is caused by a stack refurbishment that must occur for a PEM fuel cell plant operating at that capacity factor over a 40 year plant life with a durability of 25,000 hours.

Finally, it is useful to consider the large required capacity of peaking power plants in the U.S. In 2021, there were about 1000 peaking power plants with a capacity of about 237,000 MW, nearly a quarter of the U.S. total generation capacity, which generated about 130 TWh of power and thus operated at an average annual capacity factor of about 6% (U.S. Government Accountability Office (GAO) 2024)**.** With the projected costs for peaking power plants using heavy duty vehicle PEM fuel cells compared to NGCTs cost detailed above, the savings from these PEM plants could potentially be substantial.

3 Discussion

The most significant finding elicited by this study is that the LCOE of stationary PEM fuel cell power plants is potentially already competitive with that of NGCT plants given the current high costs of gas turbines, if hydrogen is available at around $1.20/kg. This is significant because it means that PEM fuel cells could provide an alternative option for utilities that need peaking power capacity soon and cannot wait for 4-7 years for delivery of a gas turbine. Additional benefits of PEM fuel cell plants include dynamics that are similar if not faster than NGCTs, and the fact that they have zero or near-zero criteria pollutants such as NOx, SOx, carbon monoxide, and hydrocarbons (National Fuel Cell Research Center (NFCRC) 2025), which can speed up permitting in urban areas. With these potential advantages, the primary drivers for whether PEM fuel cells can be deployed for stationary power in the near future are the cost and availability of hydrogen fuel and the PEM fuel cell industry's manufacturing capacity and supply chain readiness.

This study also illustrates significant cost reductions are possible for stationary PEM fuel cell power plants, though perhaps not to levels comparable to the U.S. Department of Energy's targets for vehicular fuel cell systems (Marcinkoski 2019). There are several potential avenues of cost reduction this study did not explore, however. These include potential learning in installation labor, improvements in fuel cell module efficiency and power density, economies of scale via bulk purchase of BOP materials, and development of PEM fuel cell stacks designed specifically for stationary power generation. There is also some degree of uncertainty to both current and future total overnight cost estimates, though quantifying that uncertainty is not straightforward.

This leads to several caveats to this study worth mentioning. This study assumes the power density of PEM fuel cell modules, inverters, and transformers remains constant over time. PEM fuel cell manufacturers are working to increase module volumetric power density, however, and the power density of inverter/MVT units might increase as well if stationary PEM fuel cell plants, as well as other applications, provide a motivation for them to do so. Higher power density of these components could enable shorter lengths of pipe and cable and fewer valves and fittings. Increases in heavy-duty PEM fuel cell power density will be driven by a desire to achieve a lighter-weight, more compact package for heavy-duty vehicle applications, which might desire total power output up to two to three times higher than the 125-kW PEM fuel cell module employed for analysis in this study. Determining what power density is feasible, however, requires detailed research, development, and demonstration that is well beyond the scope of this study. This study also assumes fuel cell module design-point efficiency remains constant over time, suggesting performance improvements are used to push higher current densities to achieve lower fuel cell stack costs. It is possible, however, that in the future the balance between stack cost and efficiency might shift toward higher efficiency at the expense of higher stack cost to achieve lower BOP costs and lower hydrogen consumption. Properly determining this balance would require detailed stack and system-level optimization that is beyond the scope of this study.

Significant deployment of PEM fuel cell power plants will also require that adequate supply chains are in place to support their development. Based on reported manufacturing capacities of North American PEM fuel cell manufacturers (Ballard 2020), it is likely already possible to develop several 100-MW PEM fuel cell power plants; rapid deployment beyond that might depend on expanded fuel cell manufacturing capacity. The supply chain readiness and deployment timescales for PEM fuel cells have not been evaluated for stationary power.

It should also be noted that stationary PEM fuel cell plants might benefit from purpose-built, larger PEM fuel cell stack modules with larger cells. Multiple smaller modules require a greater number of valves, flanges, and reducing tees, as well as more total length of cable and pipe, whereas fewer large modules would require fewer of these components, thereby simplifying plant installation. It is unclear, however, if and/or when there will be a sufficient market size for dedicated stationary PEM fuel cell stacks for these benefits to justify the development of larger stacks. Some design details such as PEM fuel cell efficiency and durability could affect and be affected by the dispatch strategy for the plant, which this study does not explore.

Finally, it is important to recognize this study performed analysis using national averages, and many costs such as land, permitting, EPC, labor, and taxes could vary significantly from region to region. Plant siting will likely require a balance between hydrogen fuel availability, transmission distance, and permitting costs, which could impact the overall capital cost of a project. At the low capacity factors expected for these PEM fuel cell plants, hydrogen would likely be supplied by large producers primarily supporting other applications. In the near-to-mid term, these supplies include steam methane reforming of natural gas. Geologic hydrogen is also a growing area of interest and could be an attractive option for fueling PEM fuel cell power plants (Ellis and Gelman 2024).

On the demand side, PEM fuel cell plants could be an attractive option for powering large-scale data centers that aim to avoid lengthy grid interconnection queues. Both PEM fuel cells and data center servers operate with low-voltage DC power as well. Some of the power electronics and grid interconnection infrastructure included in this study could hypothetically be bypassed in a PEM fuel cell power plant tightly integrated with a dedicated data center, potentially reducing total plant cost by up to $325/kW associated with inverters, transformers, transmission to the nearest grid interconnection point, and the EPC and contingency costs associated with these components.. Data centers and PEM fuel cell plants both require cooling, and co-locating the power plant with a data center would also introduce the possibility to take advantage of economies of scale and system intensification via combined cooling loads. This concept is already a commercial reality; the company ECL delivered one modular hydrogen fuel cell-powered data center in Mountain View, California (Yadav 2024), and plans to build out a one Gigawatt off-grid hydrogen powered data center near Houston (Vincent 2024). The competitiveness of PEM fuel cells for data centers might be improved by operating them at lower current densities (and therefore higher efficiency) relative to those considered in this study to reduce hydrogen fuel costs; they might also need to be built more robustly to have higher durability. As a result, the capital cost of such a plant would increase relative to the values shown in this study. The optimal efficiency and durability would likely vary based on an individual data center's load factor and is not immediately obvious. Fully exploring the potential cost savings of such concepts is beyond the scope of the present study and is a recommended subject for future analysis.

4 Conclusions

This study presents an engineering cost analysis of heavy-duty PEM fuel cells installed for stationary applications. We employed geometric and technical features of actual hardware and created a modeling framework that lays out a stationary PEM fuel cell plant to quantify the total lengths and sizes of pipes, cables, conduit, fittings, and valves to enable the calculation of all BOP material and labor costs. This modeling framework, named FC-PLACER, is open source and publicly available at www.github.com/NatLabRockies/FC-PLACER. This study finds PEM fuel cell systems could potentially be installed at the 100-MW scale with today's technology for an overnight cost of $1,352/kW_{AC}$, which is within the range of costs for NGCTs (Sargent & Lundy 2023; GridLab et al. 2025). By 2050, PEM fuel cell systems could see total overnight costs ranging from $924/kW to $1,142/kW when accounting for potential cost reductions in PEM fuel cell modules and inverters but not including potential cost improvements listed below that were beyond the scope of this study. When comparing the LCOE of PEM fuel cell power plants to that of NGCTs with current gas turbine costs, we find that the former could be cost competitive with capacity factors up to approximately 5.5% when fueled by hydrogen produced from natural gas; at lower capacity factors, PEM fuel cell plants could be cost competitive with higher hydrogen prices. These results suggest that heavy-duty PEM fuel cells could be a cost-competitive option for providing hydrogen-fueled stationary peaking power for the grid, providing an alternative option for serving new peak power demand so that gas turbines can be reserved for NGCCs, where they can have a greater impact in meeting growing U.S. electricity demand.

There are several research activities beyond the scope of this study that could be explored in additional analysis. These include the potential of reducing costs through bulk purchases; improvements in fuel cell and power electronics volumetric power density to lower structural and electrical BOP costs; and optimization of stack design to balance stack costs with BOP costs and hydrogen consumption. Permitting costs might also be different for hydrogen systems, and these cost estimates could be made more specific to fuel cells and consider potential reductions for future scenarios. Permitting, land, interconnection, EPC, and tax costs could all vary by location as well, so analyses for specific projects should consider local costs. Analysis could also refine estimates of fixed and variable operating costs for these power plants and identify potential cost savings in cooling, structural, and electrical BOP costs associated with co-locating PEM fuel cell power plants with behind-the-meter demand points such as data centers. Finally, future work could expand upon previous capacity expansion and production cost modeling efforts to form a better picture of how PEM fuel cell power plants might enable the United States to meet projections for growing electricity demand.

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Appendix

Table A-1. Cable Costs in U.S. Dollars per Foot

Gauge or kcmil	Aluminum Low-Voltage Cable	Copper Medium-Voltage Cable
2	0.75	
1	2.17	
1/0	1.8	13.39
2/0	2.5	14.98
3/0	3.25	16.98
4/0	3.25	19.5
250	3.17	21.22
300	3.56	
350	3.87	25.69
400	5.18	
500	5.19	32.4
600	7.21	
750	4.67	51.11

Table A-2. Liquid-Tight Conduit Size and Cost

Trade Size	Inside Diameter (in)	Cost ($/ft)
0.5	0.63	6.05
0.75	0.83	8
1	1.05	15.85
1.25	1.38	23.89
1.5	1.61	28.67
2	2.06	35.64
2.5	2.47	47.11
3	3.17	68.15
4	4.02	96.7

Table A-3. Valve, Fitting, and Instrumentation Equipment Costs ($US/each)

NPS	Low-Pressure SS Unthreaded Pipe Flanges	Low-Pressure SS Threaded Pipe Flanges	Thin-Wall Butt-Weld SS Unthreaded Pipe Fittings*	H_2 Shutoff Valve	Coolant Shutoff Valve	Pressure Relief Valve	Condensate Trap	Thermo-Couples
0.125	44	51	45		1,890			95
0.25	44	51	45	241	190	300		
0.375	44	51	45		190			
0.5	44	51	45		190			
0.75	62	57	45		227		16	
1	62	73	45		280			
1.25	75	84	77		424			
1.5	84	103	49		424			
2	105	126	50		608			
2.5	149	172	125		1,208			
3	176	198	93		1,294			
3.5	231	315	136		1,754			
4	231	315	136					
4.5	330		335					
5	330		335					
6	330		335					
8			667					
10			1,429					
12			1,959					

Table A-4. Safety Equipment Costs

Component	Cost per Unit ($2022)	Cost References
IR-UV cameras	6,181	(Det-Tronics 2025)
Hydrogen sensors	1,830	(RKI Instruments 2025)
Ultrasonic gas leak detectors	30,000	(Instrumart 2025)

Table A-5. Labor Hours for Various Installation Activities

Cost Category	Job Quantity Description	Labor Hours per job Unit	Cost References
Cooling pad foundation	Square feet of space	0.137 hr/ft^2	(Ramasamy et al. 2022)
Trenches	Total combined length of coolant piping external to the FCBs and medium-voltage AC cabling	0.017 hr/ft	(Ramasamy et al. 2022)
Access roads and parking	Total plant acreage	0.067 hr/acre	(Ramasamy et al. 2022)
Security fencing	Perimeter of power plant	0.097 hr/ft	(Ramasamy et al. 2022)
Temporary office	One per plant	32 hours per office	(Ramasamy et al. 2022)
Storage boxes	6 per 100 MW	8.9 hr/box	(Ramasamy et al. 2022)
Site preparation and surveying	Total plant acreage	71.3 hr/acre	(Ramasamy et al. 2022)
Junction/combiner boxes	One for each inverter/MVT	$1,100/inverter/MVT	(Ramasamy et al. 2022)
Combining switchgears	One per plant	$160,000	(Ramasamy et al. 2022)
High-voltage transformer substation	One per plant	$42.49/kW$_{AC}$	(Ramasamy et al. 2023)

Table A-6. Labor Hour Distribution for Various Installation Activities, Based on Ramasamy et al. (2022)

Cost Category	Common Laborers	Electricians
Cooling pad foundation	100%	
Trenches	100%	
Security fencing	100%	
Junction/combiner boxes		100%
Combining switchgears	50%	50%
High-voltage transformer substation	50%	50%

Table A-7. Page Numbers From Page (1999) for Pipe Shop and Field Handling

Task	Quantity	Labor Hour Page Number	Alloy Modification Page Number
Hydrogen and coolant pipe shop handling	Feet of piping	2	146
Hydrogen and coolant pipe field handling	Feet of piping	76	148

Table A-8. Quantification Methods and Page Numbers From Page (1999) for FCB Installation Tasks

Task	Number per Fuel Cell Module	Number per Pod	Number per Row	Labor Hour Page Number	Alloy Modification Page Number
Very small hydrogen pipe machine cutting plain ends	4			42	156
Very small coolant pipe machine cutting plain ends	8			42	156
Very small hydrogen pipe machine beveling for welding	4			46	156
Very small coolant pipe machine beveling for welding	8			46	156
Hydrogen shutoff valve flange weld shop fab	2			17	154
Coolant shutoff valve flange threaded shop fab	4			13	150
Hydrogen shutoff valve field handling	1			83	
Coolant shutoff valve field handling	2			83	
Small hydrogen pipe machine cutting plain ends	2			42	156
Small coolant pipe machine cutting plain ends	4			42	156
Small hydrogen pipe machine beveling for welding	2			46	156
Small coolant pipe machine beveling for welding	4			46	156
Small hydrogen pipe reducing tee connectors welded field fab	3			89	154
Small coolant pipe reducing tee connectors threaded field fab	6			85	150
FCB small coolant pipe stub-in welded field fab		12		89	150

Task	Number per Fuel Cell Module	Number per Pod	Number per Row	Labor Hour Page Number	Alloy Modification Page Number
Medium hydrogen pipe machine cutting plain ends		6	2	42	156
Medium coolant pipe machine cutting plain ends		12	4	42	156
Medium hydrogen pipe machine beveling for welding		6	2	46	156
Medium coolant pipe machine beveling for welding		12	4	46	156
FCB medium pipe stub-in welded field fab			2	89	150
FCB coolant air relief valve field handling		6		83	
FCB hydrogen pressure relief valve field handling		6		83	
FCB coolant air relief valve flange screw type field fab		6		83	150
FCB hydrogen pressure relief valve flange screw type field fab		6		83	150
Medium hydrogen pipe reducing tee connector welded field fab		18		89	154
Large hydrogen pipe reducing tee connector welded field fab			3	89	154
Fuel cell coolant thermocouple	1			180	

Table A-9. Quantification Methods and Page Numbers From Page (1999) for Cooling Pad Installation Tasks

Task	Number per Cooler	Number per Row	Labor Hour Page Number	Alloy Modification Page Number
Small coolant pipe machine cutting plain ends	4	0	42	156
Small coolant pipe machine beveling for welding	4	0	46	156
Coolant shutoff valve flange threaded shop fab	4	0	13	150
Small coolant pipe stub-in welded field fab	4	0	85	150
Coolant shutoff valve field handling	2	0	83	
Medium coolant pipe machine cutting plain ends	2	2	42	156
Medium coolant pipe machine beveling pipe for welding	2	2	46	156
Medium coolant pipe stub-in welded field fab	0	2	85	150
Cooling bay coolant thermocouple	1		180	

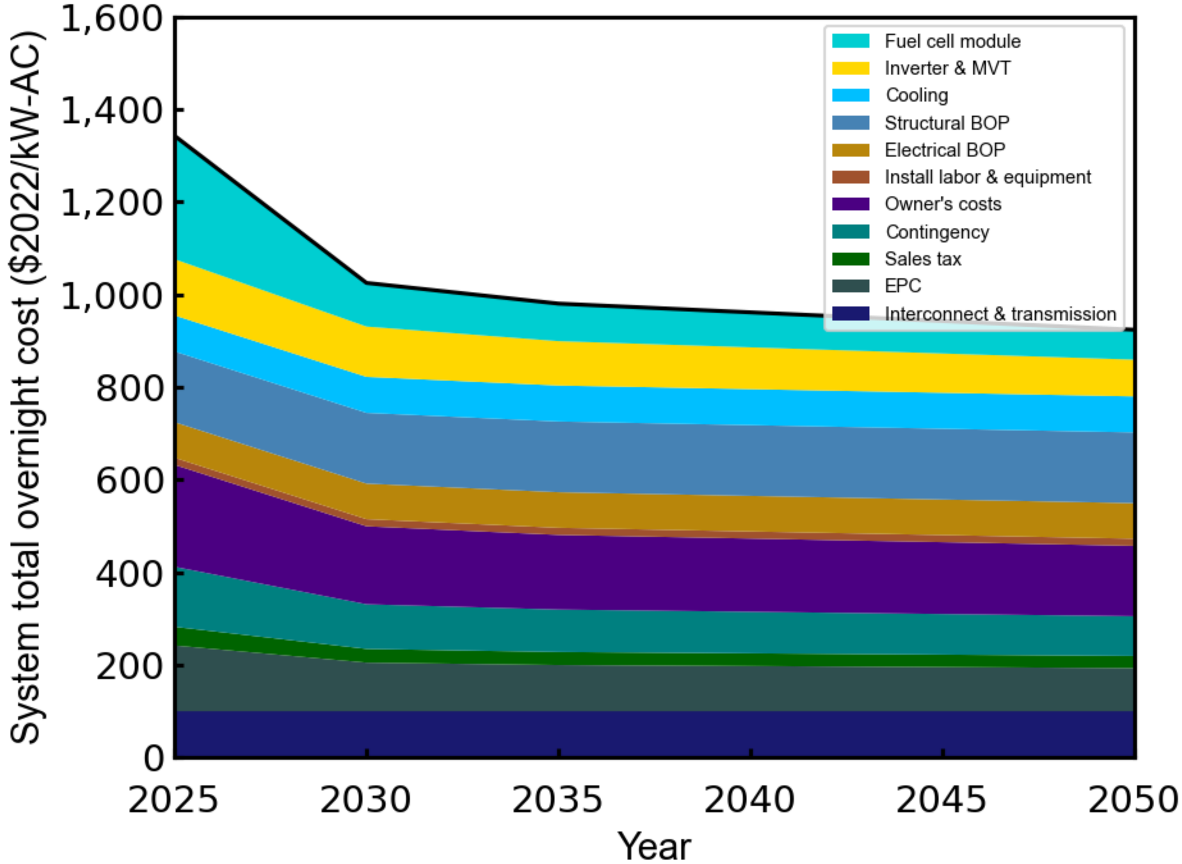

Figure A-1. PEM fuel cell system total overnight cost breakdown for the low-cost scenario

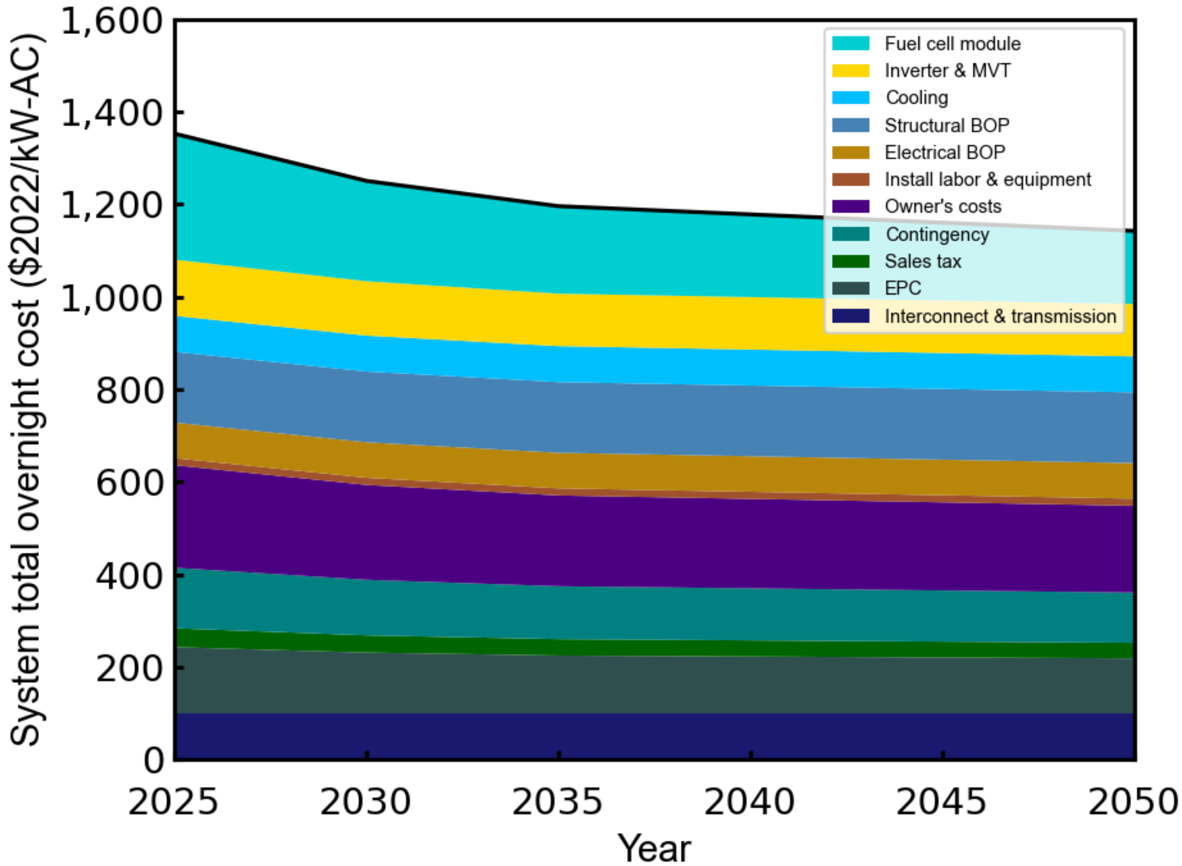

Figure A-2. PEM fuel cell system total overnight cost breakdown for the high-cost scenario