ECONOMIC EVALUATION OF A COUPLED NUCLEAR POWER PLANT AND HYDROGEN PRODUCTION FACILITY: A CASE STUDY

JAKUB TOMAN, RADHAKRISHNA TUMBALAM GOOTY, JAFFER GHOUSE, ALEXANDER DOWLING

DISPATCHES

Design Integration and Synthesis Platform to Advance Tightly Coupled Hybrid Energy Systems

September 15, 2023

INL/RPT-23-03528

Disclaimer

Jakub Toman[1]*: Methodology, Formal Analysis, Writing – Original Draft, Visualization;*
Radhakrishna Tumbalam Gooty[2,3]*: Conceptualization, Methodology, Software, Formal Analysis, Visualization;*
Jaffer Ghouse[2,3]*: Conceptualization, Methodology;*
Alexander Dowling[4]*: Conceptualization, Methodology, Writing – Review & Editing, Funding acquisition.*

[1]Idaho National Laboratory, Idaho Falls, ID.
[2]National Energy Technology Laboratory (NETL), Pittsburgh, PA.
[3]NETL support contractor, Pittsburgh, PA.
[4]Department of Chemical and Biomolecular Engineering, University of Notre Dame, Notre Dame, IN.

Acknowledgements:

This work was conducted as part of the Design Integration and Synthesis Platform to Advance Tightly Coupled Hybrid Energy Systems (DISPATCHES) project through the Grid Modernization Lab Consortium with funding from the U.S. Department of Energy's Office of Fossil Energy and Carbon Management, Office of Nuclear Energy, and Hydrogen and Fuel Cell Technology Office.

Suggested Citation:
J. Toman, R. Tumbalam Gooty, J. Ghouse, A. Dowling, "Economic Evaluation of a Coupled Nuclear Power Plant and Hydrogen Production Facility: A Case Study," Idaho National Laboratory, Idaho Falls, September 15, 2023.

DISPATCHES TEAM

National Energy Technology Laboratory
David Miller, Jaffer Ghouse[1,2], Andrew Lee[1], Radhakrishna Tumbalam Gooty[1], Naresh Susarla[1], Andres Joaquin Calderon Vergara[1,2]

Sandia National Laboratories
John Siirola, Darryl Melander, Edna Soraya Rawlings, Kyle Skolfield, Jordan Jalving[2]

Lawrence Berkeley National Laboratory
Dan Gunter, Oluwamayowa Amusat, Keith Beattie, Ludovico Bianchi

National Renewable Energy Laboratory
Wesley Jones, Darice Guittet, Benard Knueven, Ignas Satkauskas, Abinet Eseye[2]

Idaho National Laboratory
Aaron Epiney, Joshua Cogliati, Andrea Alfonsi[2], Konor Frick[2], Jason Hansen, Cristian Rabiti[2], Jakub Toman, Ramon K. Yoshiura, Gabriel J. Soto

University of Notre Dame
Alexander Dowling, Xinhe Chen, Xian Gao[2]

[1]*NETL Support Contractor*
[2]Contributed to the project but the person is no longer affiliated with the organization.

INL/RPT-23-03528
Revision 0

Economic Evaluation of a Coupled Nuclear Power Plant and Hydrogen Production Facility: A Case Study

An industrial use case of DISPATCHES

Jakub Toman, Radhakrishna Tumbalam Gooty, Jaffer Ghouse, Alexander Dowling

August 2023

Idaho National Laboratory
Idaho Falls, Idaho 83415

http://www.inl.gov

Prepared for the
U.S. Department of Energy
Office of Nuclear Energy
Under DOE Idaho Operations Office
Contract DE-AC07-05ID14517

Page intentionally left blank

ABSTRACT

This study optimized the design sizes and operation of a power-to-hydrogen-to-power integrated energy system to allow a base load power plant to operate flexibly in the energy market. In collaboration with a utility industry partner, the system, consisting of an electrolyzer, compressors, storage tank, and fuel cell, was optimized under conditions specific to the proposed project at the site of a nuclear power plant. The Design Integration and Synthesis Platform to Advance Tightly Coupled Hybrid Energy Systems (DISPATCHES) maximized net present value by optimizing sizing of components and dispatch decisions. Revenues included sale of electricity, capacity payments typical of the New York Independent System Operator, and the section 45V hydrogen production tax credit of the Inflation Reduction Act of 2022 (the tax credit was assumed to be available to legacy plants in the absence of clear guidance at present). Under default assumptions which excluded many capital expenditures, the base case optimized solution had a net present value of $1.4 million over a 30 year lifetime, with a 0.365 MW fuel cell operating nearly continuously and 85% of revenues supplied by the hydrogen production tax credit (which was counted as a revenue regardless of profit, thus assuming credit monetization or offset of taxes within the larger firm was possible in all years). Beyond the base case, a sensitivity study elucidated drivers of the economics as capacity payment rate and hydrogen production tax credit rate vary. Additional sensitivity studies also extended results to variation of other, previously fixed parameters, including the fuel cell capital cost, and to imposition of further constraints. Optimization was also repeated for the default assumptions but recognizing tax credits upon use of hydrogen rather than upon its production, producing no change in the optimal solution. Most notably, capacity payments above $15/kW-month drove optimal fuel cells multiple times larger than those with the default estimated capacity payment of $2.5/kW-month (approaching 11 vs. 0.365 MW), and these larger fuel cells operated rarely (capacity factors of ~0.03). Furthermore, when the hydrogen production tax credit was provided for only 10 years, under the specific assumptions of this study (e.g., neither site preparation costs nor electrolyzer capital cost counted), the optimal solution avoided economic loss by ceasing system operation after the 10th year. Viewed broadly, this study demonstrated the capabilities of DISPATCHES, which can be user-adapted to serve other industrial case studies.

Page intentionally left blank

CONTENTS

FIGURES

TABLES

ACRONYMS

CAPEX	capital expenditure
CP	capacity payment
DISPATCHES	Design Integration and Synthesis Platform to Advance Tightly Coupled Hybrid Energy Systems
FC	fuel cell
FOM	fixed operating and maintenance expenses
HPTC	hydrogen production tax credit
IRA	Inflation Reduction Act of 2022
NPP	nuclear power plant
NPV	net present value
NYISO	New York Independent System Operator
O&M	operation and maintenance
VOM	variable operating and maintenance expenses
ZNPPC	zero-emission nuclear power production credit

Page intentionally left blank

Economic Evaluation of a Coupled Nuclear Power Plant and Hydrogen Production Facility: A Case Study

EXECUTIVE SUMMARY

This study quantifies the opportunities of hybridizing a baseload nuclear power plant (NPP) with hydrogen production and storage to increase operational flexibility and enable more dynamic participation in energy markets. An NPP operator with an existing electrolyzer sought to explore the value of such a system and how to optimize its operation, motivating specific questions as the industry partner to this case study. The resulting study is one of two industrial case studies in the Design Integration and Synthesis Platform to Advance Tightly Coupled Hybrid Energy Systems (DISPATCHES) project of the U.S. Department of Energy's Grid Modernization Laboratory Consortium, and applies the DISPATCHES software to optimize system component sizing and their hourly operation.

As renewable generation increases, volatility in energy market prices is also expected to increase and lessen the viability of baseload generators, such as NPPs. These market trends drive NPP operators to explore opportunities for increased flexibility. While generating hydrogen at times of low prices and storing it for fuel-cell-based generation allows for electricity sales at times of high prices, the techno-economic case for this approach is not straightforward and requires further analysis. The power-to-hydrogen-to-power process loses the majority of energy input, and so, profitability depends on sufficient variation in market prices and the timing of storage and discharge decisions to offset the cost of lost energy. Additionally, appropriate sizing of components also factors into profitability. Determining the timing of operational decisions and the sizing of components to maximize profit is a problem highly suited to mathematical optimization.

The solutions in this report result from simultaneously optimizing the operation and sizing of a hydrogen integrated energy system with a price-taker approach, with operating decisions determined for every hour of one year. Revenues include the sale of electricity to the energy market, capacity payments (with simplified assumptions for the New York Independent System Operator capacity market), and the hydrogen production tax credit (HPTC)[a] of section 45V of the Inflation Reduction Act of 2022 (IRA). Limited capital expenses, operating expenses including electricity used, and periodic maintenance including cell replacement were considered as costs, along with taxes.

Some of the key assumptions and parameters will now be briefly touched upon. Electrolyzer and fuel cell efficiencies correspond to polymer electrolyte membrane technology. The existing electrolyzer does not contribute a capital expense, and the remaining capital expenses only include purchase of components (e.g., fuel cell capital cost of $1,000/kW)—notably, capital expenses for groundwork, engineering, labor, installation, and for purchase of the initial level of electrolyzer capacity are not counted. Electricity is purchased at market prices, hydrogen is not sold, and the HPTC is fully available throughout the 30-year system lifetime (except for results in Section 2.8). Table 7 lists the default values of all parameters and provides notes about their origin.

Results for a fixed electrolyzer capacity and with default revenue rates—an estimated present-day capacity payment ($2.5/kW-month) and maximum possible tax credit ($3/kg)—are the base case. The optimized solution attains a modest net present value (NPV) of $1,360,000 with a storage tank sized for 4 hours of hydrogen consumption at the full power of a 0.365 MW fuel cell. The system produces hydrogen nearly continuously while also generating electricity on the same schedule (capacity factors greater than 0.99). Thus, the present-day capacity payment, HPTC rate, and variation of market prices are insufficient

[a] In the present analysis, the HPTC is treated as non-taxable revenue. This simplifying assumption implies that the HPTC always has value to the operating firm, regardless of the operating firm's profitability or ability to monetize the credit. Also, it is assumed that hydrogen production using existing capacity of the NPP will qualify for the HPTC in practice once the relevant tax rule is finalized.

to reach a multimillion-dollar NPV in the base case. As the HPTC is 85% of the total revenue, its presence is crucial to the system's economic viability.

Beyond the base case, this study analyzed seven additional cases to better expound on the dominant effects. Each case was intended to answer these questions:

1. Which source drives revenue under various HPTC and capacity payment rates?
2. What is the effect of adding electrolyzer capacity?
3. What is the effect of prescribing (fixing) the fuel cell capacity?
4. What is the effect of changes in the fuel cell capital cost?
5. Does recognizing HPTC revenue upon the use of H_2, rather than production of H_2, affect the solution?
6. What is the effect of accounting for the zero-emission nuclear power production tax credit? (ZNPPC; section 45U of the IRA; see Section 1.3.1.1)
7. Can the system remain profitable if the HPTC is not renewed after 10 years?

In the first case study listed, HPTC and capacity payment (CP) rates were varied, forming a simple sensitivity study in two variables. For all but two of the remaining cases, the HPTC-CP sensitivity study was repeated under some additional change to another parameter or the method of accounting for tax credits. The listed cases and base case are summarized in Table 1, which presents the differences among them.

Table 1. Overview of parameters for all cases.

<table>
<tr><th></th><th>HPTC Rate [$/kg]</th><th>CP Rate [$/kW-month]</th><th>Electrolyzer Capacity [MW_e] (alternate name)</th><th>Fuel Cell Capacity [MW_e]</th><th>Fuel Cell Capital Cost Rate [$/kW] (alternate name)</th><th>System Lifetime [years]</th><th>Other</th></tr>
<tr><td>Base case</td><td>3</td><td>2.5</td><td>1.0625</td><td>optimized</td><td>1,000</td><td>30</td><td></td></tr>
<tr><td>1</td><td>0–3</td><td>2.5–30</td><td>1.0625</td><td>optimized</td><td>1,000</td><td>30</td><td></td></tr>
<tr><td>2</td><td colspan="2">as Case 1</td><td>2.0625 ("+ 1"),
3.0625 ("+ 2")</td><td>optimized</td><td>1,000</td><td>30</td><td></td></tr>
<tr><td>3</td><td colspan="2">as Case 1</td><td>1.0625,
2.0625 ("+ 1"),
3.0625 ("+ 2")</td><td>optimized,
1, 2, 5</td><td>1,000</td><td>30</td><td></td></tr>
<tr><td>4</td><td colspan="2">as Case 1</td><td>1.0625</td><td>optimized</td><td>500 ("-50%"),
700 ("-30%"),
850 ("-15%"),
1,250 ("+25%")</td><td>30</td><td></td></tr>
<tr><td>5</td><td colspan="6">as Case 3</td><td>Note 1</td></tr>
<tr><td>6</td><td colspan="6">as Case 1</td><td>Note 2</td></tr>
<tr><td>7</td><td colspan="5">as Case 1</td><td>10, 15, 30</td><td>Note 3</td></tr>
<tr><td colspan="8">Note 1: The HPTC is recognized (accounted for) by the mass of hydrogen consumed in the fuel cell, rather than by the mass of hydrogen produced by the electrolyzer.</td></tr>
<tr><td colspan="8">Note 2: The ZNPPC is earned on electricity sold from the fuel cell and forms a nontaxable revenue; simultaneously, an opportunity cost is incurred on the loss of ZNPPC by the NPP due to diversion of electricity to the electrolyzer. The rate of the ZNPPC is $15/MWh.</td></tr>
<tr><td colspan="8">Note 3: When calculating NPV, the HPTC revenue is included for only 10 years and becomes zero beyond that.</td></tr>
</table>

Key findings for the listed cases beyond the base case are summarized as follows:

1. A capacity payment rate of $15/kW-month and above drives a noticeable change in the optimized solution compared to lower CP rates: large fuel cells approaching 11 MW earn capacity payments that dominate the revenue and rarely operate (fuel cell capacity factors of ~0.03). Storage tanks are up to 10% larger than needed for 4 hours of operation, with variations in stored mass throughout the year, while the electrolyzer operates nearly continuously (capacity factors above 0.95; the fuel cell requires much more H_2 at full power than continuous operation of the electrolyzer can supply). At CP rates below $15/kW-month, HPTC is the dominant revenue, and solutions are similar to the base case.
2. Additional electrolyzer capacity only became warranted when the CP was less than $10/kW-month while the HPTC was $2/kg or more (rates that match default, present-day assumptions).
3. When fixing the fuel cell capacity, addition of 2 MW of electrolyzer capacity with a 1 MW fuel cell reached the highest NPV, with addition of larger electrolyzer capacities presumed to increase NPV even further.
4. Lowering the fuel cell capital cost (from $1,000/kW) modestly increased NPVs and turned marginally unprofitable cases to profitability; for subcases without HPTC, a 15% drop in cost lowered the necessary CP level by approximately $5/kW-month (from $20/kW-month to $15/kW-month).
5. The recognition of HPTC upon the use of hydrogen rather than upon its production had no effect on the solution of the base case or of other cases trialed (e.g., Case 3).
6. When the impact of partial loss of the zero-emission nuclear power production tax credit was considered, NPV decreased significantly (from $1,360,000 to $510,000), as the ZNPPC revenue earned at the fuel cell cannot offset the larger amount of ZNPPC lost on power diverted from the grid and used at the electrolyzer (the latter is largely due to the low roundtrip efficiency of the power-to-hydrogen-to-power process).
7. Finally, when the HPTC was only earned for 10 years, a very modest profitability can be preserved by ceasing operation after year 10 (NPV of $740,000); however, increased electricity prices could further erode this low NPV (as higher prices increase the cost to generate hydrogen, which outweighs higher prices for electricity sales).

Importantly, the capital expenses included in calculating NPV were specific to an existing site as specified by the industry partner. To make this case study more applicable to other sites, additional capital expenses were included using an estimated range in Appendix A.

The analysis framework demonstrated in this study may assist stakeholders in determining policies needed for viability of the carbon-neutral technology used here. For example, the capacity payment rate for which economics are favorable can be identified. Moreover, the mathematical models and analysis scripts in DISPATCHES can be extended to other systems and to the stipulations of other industrial use cases.

1. METHODS

1.1 Problem Statement

The objective of optimization is stated as: Optimize the design and operation of an integrated energy system shown in Figure 1 that generates, stores, and uses H_2, thus enabling flexible operation using electricity from a baseload power plant. Electricity is purchased and sold at time-varying prices in the New York Independent System Operator (NYISO) market, with further revenue from the CP within the NYISO capacity market and from the HPTC of the IRA (section 45V). The NPV, as a function of the optimized design and operational variables, is to be maximized (indicating profitability)., An electrolyzer of known capacity is already installed at the power plant site.

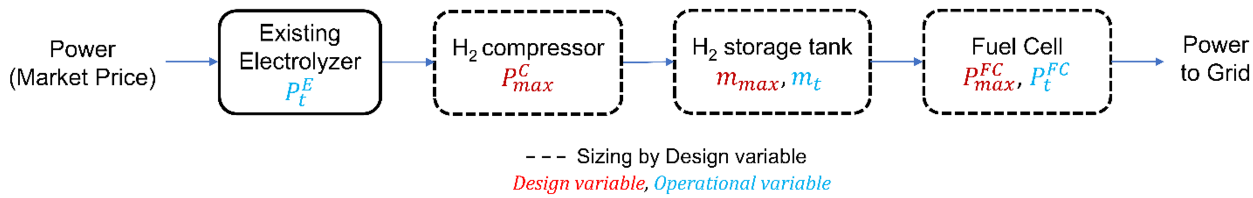

Figure 1. Schematic of the proposed hydrogen generation, storage, and power generation system. Design and operational variables are defined in Section 1.2. (This diagram is accurate for the base case and most cases.)

Because 15% of the electrolyzer's capacity is set aside for generating hydrogen for use in the NPP, 85% of the capacity is available to the present system, making P_{max}^E = 1.0625 MW (by electrical power). While the electrolyzer capacity is fixed[b], its use is an operational decision. The cost of electricity used by the electrolyzer is at the day-ahead market (DAM) price (see Section 1.4).

In order for the system to qualify for CP in the NYISO capacity market, the storage tank must maintain a minimum level of fuel of enough hydrogen for 4 hours of maximum electrical power at the fuel cell.

1.2 System Mathematical Models

As shown in Figure 1, the system consists of an electrolyzer that produces hydrogen gas, a storage tank for hydrogen gas, and a fuel cell that converts hydrogen gas into electric current. System sizing is described by design variables, while its operation is described by operational variables.

A ***design variable*** is determined before the system is built. It is time-invariant in the optimization problem. Design variables to be optimized include storage tank capacity (expressed in terms of mass) m_{max}, fuel cell capacity (expressed as maximum electrical power) P_{max}^{FC}, and compressor maximum electrical power P_{max}^C (proportional to the maximum rate of hydrogen that can be passed through the compressor, as described later). The electrolyzer capacity (maximum power) P_{max}^E is fixed—set to match the existing electrolyzer's available capacity—and is thus not a design variable. The design variables are summarized in Table 2.

[b] In cases with increased electrolyzer capacity, the electrolyzer is still a fixed variable, as these cases prescribe the quantity of the increased capacity.

Table 2. Design variables.

Design Variable	***Symbol [Units]***
Compressor maximum power	P_{max}^{C} [MW]
Storage tank capacity	m_{max} [kg]
Fuel cell capacity	P_{max}^{FC} [MW]

An ***operational variable*** can vary with time throughout the plant lifetime. Changes in operational variables can be interpreted as charging or dispatch decisions (i.e., produce hydrogen, store hydrogen, and generate electricity for sale to the energy market). The operational variables to be optimized are electrolyzer electrical power P_t^E and fuel cell electrical power P_t^{FC}. The stored mass of hydrogen m_t may be viewed as an operational variable; however, as the rate of hydrogen production is a function of P_t^E and the rate of hydrogen consumption is a function of P_t^{FC}, m_t is a function of P_t^E and P_t^{FC}. Thus, one of the three operational variables is always determined when the other two are known. The compressor power P_t^C is a function of electrolyzer power, as defined later in this section, and so is not an operational variable (not independently optimized). Operational variables have hourly resolution and are listed in Table 3.

Table 3. Operational variables.

Operational Variable	***Symbol [Units]***
Electrolyzer power	P_t^E [MW]
Stored mass	m_t [kg]
Fuel cell power	P_t^{FC} [MW]

The design and operational variables are known once the optimizer reaches a solution; the ***optimizer*** is the computational software used to solve the design and operation co-optimization problem (Section 1.6.1).

As the addition of the storage tank and fuel cell are optional design decisions, they may each be optimized to zero or near-zero capacity, independently. Each component is described in more detail in this section[c].

Electrolyzer

The polymer electrolyte membrane (PEM) electrolyzer converts electricity to hydrogen. Its transfer constant k^E has dimensions of mass per energy (kg/MWh) and determines the rate at which electric energy is converted to hydrogen (mass flowrate to electric power). This rate is limited by the capacity, also known as the maximum power, P_{max}^E.

The hydrogen production rate $\dot{m}$ with dimensions of mass per hour (kg/h) as a function of power input to the electrolyzer (P^E) is:

$$\dot{m}_{produced} = k^E \cdot P^E$$

where $P^E \leq P_{max}^E$.

[c] Note that symbols for all variables and most parameters include superscript letters. This usage does not signify the exponential operation. For example, in P_t^E, P is not raised to the power of E (E does not have a value but rather denotes that the symbol pertains to the electrolyzer).

The amount of hydrogen produced in one hour is thus:

$$m_{t,produced} = k^E \cdot P_t^E \cdot \Delta t$$

where the subscript t indicates a variable indexed by the hour and the time step Δt is equal to one hour.

Compressor

Compressors for hydrogen storage typically require multiple stages to achieve high pressures, but are represented as a single unit in this study. The compressors are simply modeled as a sink for electric power purchased at market price, scaled by the amount of hydrogen stored per unit time (each hour), and have no effect on the state of the stored hydrogen (state variables such as temperature and pressure are not tracked; only mass of hydrogen is tracked). The compressor's transfer constant k^C has dimensions of energy per mass (MWh/kg). The power drawn by the compressor in any given hour, P_t^C, is:

$$P_t^C = k^C \cdot m_{t,produced}$$

$$= k^C \cdot k^E \cdot P_t^E$$

Storage Tank

Hydrogen passes from the electrolyzer to the storage tank and then can be optionally dispatched to the fuel cell. This hydrogen can be stored in the tank indefinitely or be passed through immediately for use in the fuel cell. The pressure inside the tank is not modeled, and the tank has no transfer function and so has no transfer constant. Stored hydrogen is accounted for by mass.

A hydrogen mass balance is implemented as:

$$m_{t,present} - m_{t,previous} = m_{t,produced} - m_{t,consumed}$$

$$\Delta m_t = \dot{m}_{produced} - \dot{m}_{consumed}$$

where $m_{t,present}$ is the stored mass (holdup) of hydrogen in the tank at the end of the hour, $m_{t,previous}$ is the stored mass (holdup) at the beginning of the hour, $m_{t,consumed}$ is the mass of hydrogen used by the fuel cell in one hour, and Δm_t is the change in the stored mass over the hour.

A constraint applies to the stored mass m_t, satisfying the capacity market's requirement to keep a minimum amount of fuel (4 hours at maximum power) in reserve:

$$m_t \geq 4 \frac{P_{max}^{FC}}{k^{FC}}$$

where k^{FC} is the fuel cell transfer constant.

Fuel Cell

The PEM fuel cell converts hydrogen into electricity. Its transfer constant k^{FC} has dimensions of energy per mass (MWh/kg) and determines the rate at which hydrogen is converted to electric energy (mass flowrate to electric power). This rate is limited by the capacity, also known as the maximum power P_{max}^{FC}, which is a design variable.

The hydrogen consumption rate $\dot{m}_{t,consumed}$ with dimensions of mass per hour (kg/h) is:

$$\dot{m}_{t,consumed} = \frac{1}{k^{FC}} \cdot P_t^{FC}$$

where the time step Δt is equal to one hour, and k^{FC} is the fuel cell transfer constant.

The presence and the mass flowrates of water are neglected throughout the system[d]. Refer to Section 1.5 for numerical values of the transfer constants k.

Beyond the available capacity of the existing electrolyzer, and the known location for price signals (withheld in this report), the model does not use any information about the NPP. For this reason, no further treatment of the NPP is required.

1.3 Financial Mathematical Models

1.3.1 Cash Flow

Table 4 presents the components of cash flow—summing to the cash flow—and the summation of cash flow with the HPTC to form the net profit. O&M stands for "operation and maintenance." All listed quantities are annual.

Table 4. Components of cash flow and net profit, and their summation. Parentheses indicate that the line item is subtracted.

Electricity revenue
Capacity payments
(Electricity cost)
(Variable O&M expenses, excluding electricity)
(Fixed O&M expenses)
(Periodic replacement expenses)
Cash Flow
(Tax)
HPTC
Net Profit

The line items in parentheses are considered expenses and are subtracted from the revenue line items to arrive at the cash flow and net profit. For example, fixed operation and maintenance expenses are positive and are then subtracted when computing cash flow, thus numerically decreasing cash flow. Note that the periodic replacement expense is not incurred in most years.

The net profit is calculated annually as:

$$NetProfit = CashFlow + HPTC - Tax$$

The rate of the HPTC is up to \$3 per kg of hydrogen (H_2), subject to specific carbon dioxide emission standards and labor standards. This credit is expected to significantly influence the optimal solution in each case and will be treated as a sensitivity parameter to extend the applicability of the results to

[d] However, a fixed water treatment cost is included in the operating cost of the electrolyzer, as listed in Section 1.5.

situations where only part of the credit is earned (Section 2.2). The HPTC will be assumed to apply over the full project lifetime of 30 years, but is also limited to 10 years in one of the cases (Section 2.8) to explore the worst-case scenario of its expiration after 10 years. In all cases, the HPTC is treated as a nontaxable revenue, as reflected in Table 4; this approach assumes that the credit always has monetary value to the firm operating the NPP. Critically, this analysis assumes that hydrogen produced with electric power generated from the existing NPP will fully qualify for the HPTC when the tax rule is finalized[e].

Tax is defined as:

$$Tax = \max\{\,0, (R^{Tax} \cdot CashFlow - R^{Tax} \cdot Depreciation)\,\}$$

where R^{Tax} is the tax rate, and whereby the tax cannot be less than zero. Thus, tax loss carryforward is not considered.

The sum of the cash flow line items, $CashFlow$, is:

$$CashFlow =$$

$$Electricity\ revenue(P_t^{FC}, LMP_t) + Capacity\ payments(P_{max}^{FC}, R^{capac})$$

$$- Electricity\ cost\left(P_t^E, LMP_t^{E,DAM}\right) - VOM(P_t^{FC}) - FOM(P_{max}^{FC}, constants)$$

$$-\begin{cases} Periodic\ replacement\ expenses, y = 10, 20 \\ 0, y \neq 10 \cup y \neq 20 \end{cases}$$

where parentheses denote that the quantity is a function of a design variable or operational variable, such as the hourly fuel cell power P_t^{FC}, the maximum fuel cell power P_{max}^{FC}, or the hourly electrolyzer power P_t^E, where *VOM* stands for variable operation and maintenance expenses (excluding electricity cost) and *FOM* stands for fixed operation and maintenance expenses. The periodic replacement expense is nonzero only in Years 10 and 20.

The components of cash flow and tax are fully defined as:

$$Electricity\ revenue(P_t^{FC}, LMP_t) = \sum_{t=1}^{8760} LMP_t \cdot P_t^{FC}$$

$$Capacity\ payments(P_{max}^{FC}, R^{capac}) = 12 \cdot R^{capac} \cdot 1000 \cdot P_{max}^{FC}$$

$$Electricity\ cost\left(P_t^E, LMP_t^{E,DAM}\right) = \sum_{t=1}^{8760} LMP_t^{E,DAM} \cdot P_t^E + LMP_t^{E,DAM} \cdot P_t^C$$

$$FOM(P_{max}^{FC}) = F^E + F^C + F^S + F^{FC} + P_{max}^{FC} \cdot F_{linear}^{FC}$$

$$= F^E + F^C + F^S + F^{FC} + 0$$

[e] The question of eligibility of hydrogen produced using existing NPP electricity has yet to be resolved at the time of writing, and originates with concern about redirecting existing low-emission generation from the grid to hydrogen production.

$$VOM(P_t^E, P_t^C, P_t^{FC}) = \sum_{t=1}^{8760} V^E \cdot P_t^E + V^C \cdot P_t^C + V^S \cdot m_{max} + V^{FC} \cdot P_t^{FC}$$

$$= \sum_{t=1}^{8760} 0 + V^{FC} \cdot P_t^{FC}$$

$$Periodic\ replacement\ expenses = \Pi^C + \Pi^{FC}$$

$$Depreciation = CAPEX/L$$

where LMP_t is the locational marginal price (LMP) of electricity for a given hour indexed by t and provided by the chosen price signal for electricity sales (either day-ahead or real-time market); $LMP_t^{E,DAM}$ is the LMP of the chosen day-ahead price signal for electricity purchases (also for a given hour indexed by t); F^E, F^C, F^S, and F^{FC} are the fixed operating costs of the electrolyzer, compressor, storage tank, and fuel cell, respectively; F_{linear}^{FC} is the linear rate of fixed operating cost for the fuel cell (not used); V^E, V^C, and V^{FC} are the variable operating costs of the electrolyzer, compressor, and fuel cell, respectively; R^{capac} is the CP rate [f] in \$/kW-month; Π^C and Π^{FC} are the periodic replacement expenses for the compressor and fuel cell; $CAPEX$ is the total capital expenditure; and L is the system lifetime.

The HPTC revenue is calculated as:

$$HPTC = \sum_{t=1}^{8760} R^{HPTC} k^E P_t^E \cdot \Delta t$$

where R^{HPTC} is the HPTC rate in \$/kg and the time step Δt is equal to one hour.

Total capital expenditure $CAPEX$ is further a function of the design variables and of the fixed capital cost parameters:

$$CAPEX = C^C P_{max}^C + C^S m_{max} + C^{FC} P_{max}^{FC}$$

where C^C, C^S, and C^{FC} are the capital cost rates of the compressor (in \$/MW), storage tank (in \$/kg), and fuel cell (in \$/MW), respectively.

In cases where electrolyzer capacity is added, the above equation becomes:

$$CAPEX = C^E(capacity\ above\ 1.0625\ MW) + C^C P_{max}^C + C^S m_{max} + C^{FC} P_{max}^{FC}$$

where C^E is the capital cost rate of the electrolyzer (in \$/MW).

Note that the total capital expenditures do not include any costs beyond the cost of components and so do not reflect building a system at a generic site (nor do they reflect installation costs). Groundwork, engineering, labor, and installation costs are included in the case shown in Appendix A, which is an

[f] The capacity market involves auctions, and thus the capacity payment is neither guaranteed nor constant over the project lifetime. A typical capacity payment for the NYISO region is used here as a constant estimate. Furthermore, it is assumed that the hydrogen integrated energy system can be eligible for capacity payment regardless of the size of storage, and that the NPP's capacity payments will not decrease as a result of installing the hydrogen integrated energy system.

HPTC-CP sensitivity study and includes the base case. For the calculations producing Appendix A, the equation becomes:

$$CAPEX = C^{add} + C^{E}(capacity\ above\ 1.0625\ MW) + C^{C}P_{max}^{C} + C^{S}m_{max} + C^{FC}P_{max}^{FC}$$

where C^{add} is a single value used to capture added capital expenditures.

The fixed parameters LMP_t, F^E, F^C, F^S, V^E, V^C, V^{FC}, Π^C, Π^{FC}, R^{capac}, R^{HPTC}, R^{ZNPPC}, L, C^C, C^S, C^{FC}, C^E, and C^{add} are further defined and their default values given in Section 1.5.

$LMP_t^{E,DAM}$ is the price of electricity used by the electrolyzer and compressor at a given hour, under this reasoning: the opportunity cost associated with each unit of power that is not sold on the grid, equivalent to the DAM LMP for the node where the NPP is located, was used (as opposed to the real or internal cost of electricity generated by the NPP, which was not used.) For simplicity, this opportunity cost is absorbed by the modeled system as a cost. The price signals chosen to make up the series of prices indexed by *t* are discussed in Section 1.4. In using a historical price signal, the system's role in the market is taken to be a ***price taker***; the power drawn and generated is considered small relative to the overall power capacity at the grid node and so is assumed to not affect the prices at the node.

1.3.1.1 Cases with Modification to Accounting of Tax Credits

When the HPTC is recognized (earned) upon use of H_2, rather than upon its production (Section 2.6), the HPTC revenue is calculated as:

$$HPTC = \sum_{t=1}^{8760} R^{HPTC} \frac{1}{k_t^{FC}} P_t^{FC} \cdot \Delta t$$

where R^{HPTC} is the HPTC rate in \$/kg and the time step Δt is equal to one hour.

The method of accounting for the HPTC, and thus the timing of its recognition, had not been clarified by the U.S. Treasury Department at the time this study was formulated.

When HPTC expiration after 10 years is considered (Section 2.8), the net profit is calculated as:

$$NetProfit = \begin{cases} CashFlow + \begin{cases} HPTC, y \leq 10 \\ 0, y > 10 \end{cases}, Tax \leq 0 \\ CashFlow - Tax + \begin{cases} HPTC, y \leq 10 \\ 0, y > 10 \end{cases}, Tax > 0 \end{cases}$$

Finally, when the effects of the ZNPPC of section 45U of the IRA are considered (Section 2.7):

$$NetProfit = CashFlow - Tax + HPTC + ZNPPC - ZNPPC_{NPP\ Opportunity\ Cost}$$

where the ZNPPC revenue is calculated as:

$$ZNPPC = \sum_{t=1}^{8760} R^{ZNPPC} \cdot P_t^{FC}$$

and the opportunity cost of the partial loss of the ZNPPC revenue is calculated as:

$$ZNPPC_{NPP\ Opportunity\ Cost} = \sum_{t=1}^{8760} R^{ZNPPC} \cdot P_t^E$$

where R^{ZNPPC} is the ZNPPC rate in \$/MWh.

For clarity, Table 5 shows the modification of the summation of the components of cash flow with the two tax credits (HPTC and ZNPPC).

Table 5. Components of cash flow and net profit and their summation for the case including ZNPPC (Section 2.7 only), where parentheses indicate that the line item is subtracted.

Electricity revenue
Capacity payments
(Electricity cost)
(Variable O&M expenses, excluding electricity)
(Fixed O&M expenses)
(Periodic replacement expenses)
Cash Flow
(Tax)
HPTC
ZNPPC
(Opportunity cost for partial loss of ZNPPC)
Net Profit

1.3.2 Net Present Value

NPV is the optimized metric and is maximized. In this analysis, NPV is defined as:

$$\text{NPV} = \left(\sum_{y=1}^{L} \frac{NetProfit_y}{(1+r)^{(y)}} \right) - CAPEX$$

where y is the index of the sum (each representing one year), L is the lifetime of the project in years, r is the discount rate, $NetProfit_y$ is the net profit in year y, and $CAPEX$ is the total capital expenditure. Note that the NPV is not compared to the value of continuing NPP operations as they are (status quo); i.e., the do-nothing option is assumed to have zero NPV.

1.4 Time-Varying Energy Price Signals

Energy market signals $LMP_t^{E,DAM}$ and LMP_t originate with hourly LMP data from the DAM of the NYISO at the node corresponding to the NPP. (As previously stated, the integrated energy system is modeled as a price-taker.)

Historical signals for the DAM of year 2021 were used for all cases in the body of the report, because 2021 had medium values of mean, minimum, maximum, and standard deviation relative to 2019 and 2022

DAM. The years 2019, 2021, and 2022 were considered due to their recency, while 2020 was not considered due to a low average and standard deviation (presumably an effect of COVID-19 pandemic response). Table 6 gives the mean and standard deviation of each DAM price signal that was considered before the 2021 DAM was selected, as well as results for the 2022 and 2021 real-time market (RTM).

Some of the RTM signals and non-default DAM-signals were used for additional runs found in Appendix B. In all cases presented there, a DAM signal was used for the price of electricity used by the electrolyzer ($LMP_t^{E,DAM}$), even if an RTM signal was used for electricity sales from the fuel cell (LMP_t). This choice of price signal for power purchases was made in consultation with the industry partner to reflect the opportunity cost incurred by the NPP when electric power is diverted to the electrolyzer. Although the RTM operates on a 5 minute interval, hourly averaged data supplied by the system operator was used for simplicity.

Table 6. Mean and standard deviation of each price signal, including the unused 2020 DAM price signal.

Price Signal	Mean	Standard Deviation
2022 DAM	\$52.81	\$36.47
2021 DAM **(default)**	\$27.56	\$15.82
2020 DAM (not used)	\$15.12	\$6.97
2019 DAM (only in Section 2.8)	\$19.13	\$9.80
2022 RTM	\$54.40	\$70.36
2021 RTM	\$27.14	\$22.24

Each price signal is 8,760 hours long with hourly resolution.

1.5 Fixed Parameters

The parameters listed in Table 7 are fixed in the optimization problems, with three exceptions. Although each of these three parameters may be fixed in some cases, each may be varied in the sensitivity studies of other cases; they are marked "***sensitivity parameter***" (also see Table 1 for a summary of cases). The default or nominal parameters, as given here, correspond to the base case.

Table 7. Fixed parameters and their symbols and values, where "Industry Partner" denotes that the value was provided by the industry partner and "M" denotes millions.

Symbol	Parameter	Value [units]	Notes
<u>*Electrolyzer*</u>			
P_{max}^E	Max power	1.0625 MW *Higher value for cases with added electrolyzer capacity (Sections 2.3 and 2.4)* *A **sensitivity parameter** in Section 2.4*	*Industry Partner*: The available capacity of the existing electrolyzer.
k^E	Transfer constant	1000/50.4 ≈ 19.841 kg/MWh	*Industry Partner*: electrolyzer specification (50.4 kWh/kg)
C^E	CAPEX rate	\$1M/MW$_e$ for increased electrolyzer	Zero for most cases because electrolyzer is already installed.

Table 7. (continued).

Symbol	Parameter	Value [units]	Notes
		capacity cases (see Sections 2.3 and 2.4) Zero for all other cases	\$1M/MW is equivalent to \$1,000/kW (electric)
F^E	FOM	\$60,000/y	*Industry Partner*: \$5,000/month for water treatment supplies
V^E	VOM	Zero	Does not include cost of electricity (accounted for separately—relevant parameters k^E and LMP_t)
Compressors			
C^C	CAPEX rate	\$3,000/kW	Linear extrapolation to industry partner-provided pressure, from \$/kW value given in Reference 1., increased for inflation from December 2014 to April 2023 using https://www.bls.gov/data/inflation_calculator.htm, and rounded to nearest \$100/kW
F^C	FOM	20,000 \$/y	*Industry Partner*
V^C	VOM	Zero	Does not include cost of electricity (accounted for separately—relevant parameters k^C and LMP_t)
k^C	Transfer constant	0.003 MWh/kg	*Calculated value:* Linear extrapolation to industry partner-provided pressure, from kWh/kg value given in Reference 1.
Π^C	Periodic OM	\$100,000 @ 10 y, 20 y	*Industry Partner*. Irrespective of capacity (flat rate)
Storage Tank			
C^S	CAPEX rate	600 \$/kg	Reference 2.
F^S	FOM	1,000 \$/y	*Industry Partner*. Irrespective of capacity (flat rate)
V^S	VOM	0	—
Fuel Cell			
k^{FC}	Transfer constant	0.017316 MWh/kg	*Calculated value:* Minimum "stack efficiency" of 0.52 for a PEM fuel cell of Reference 3. and the lower heating value of hydrogen (33.3 kWh/kg) [Reference 4.] were multiplied: k^{FC} = 0.52•33.3/1000 [MWh/kg]

Table 7. (continued).

Symbol	Parameter	Value [units]	Notes
C^{FC}	CAPEX rate	1 M $/MW$_e$	$1000/kW (kW of electric power)
F^{FC}	FOM—flat rate	135,000 $/y	Irrespective of capacity (flat rate)
F^{FC}_{linear}	FOM—proportional	Zero	Not used
V^{FC}	VOM	2 $/MWh$_e$	General estimate
Π^{FC}	Periodic OM	$250,000 @ year 10, year 20	*Industry Partner.* Irrespective of capacity (flat rate).
Market Prices and Tax Credits			
LMP_t	Electricity price signal	LMP signal	A fixed data set, from the view of the optimization problem, that varies with time. Each hourly value is from a set of one year of hourly values. In Appendix B only, the set LMP_t will vary with choice of year and market. Further described in Section 1.4.
R^{capac}	CP rate	***Sensitivity parameter*** 2.51–30 $/(kW·month) *Default value:* 2.51 $/kW·month)	2.51 was used instead of 2.5 due to computational convergence issues (experienced in a small subset of cases, but was 2.51 used for all cases).
R^{HPTC}	HPTC rate	***Sensitivity parameter*** 0.5–3 $/kg *Default value:* 3 $/kg	Assumed to apply for full plant life, except in cases with a 10 year HPTC limit (Section 2.8).
R^{ZNPPC}	Zero-emission nuclear power production credit	15 $/MWh	When used (only in Section 2.7), assumed to apply for full plant life.
Economic parameters			
L	Project lifetime	30 y	Common value, except for cases with a shorter lifetime (only found in Section 2.8)
r	Discount rate	10%	—

Table 7. (continued).

Symbol	Parameter	Value [units]	Notes
R^{Tax}	Tax rate	29.25%	U.S. corporate tax rate of 21% plus state tax rate
C^{add}	Added CAPEX	Only in *Appendix A*: $5M, $10M	See Appendix A

1.6 Model Implementation

The model used within this study conducts dispatch optimization for 8,760 hours and computes the corresponding net profit for that single year. The resulting net profit is used in the NPV calculation with the full plant lifetime. Cash flow, tax, and tax credits are constant over the plant's lifetime, except for years in which replacement expenses are incurred; thus, the net profit is constant except for Years 10 and 20 as demonstrated in Figure 2 (with the notable exception of the case when the HPTC expires after 10 years, see Section 2.8). As NPV is the optimized quantity, optimization still applies to the entire plant lifetime.

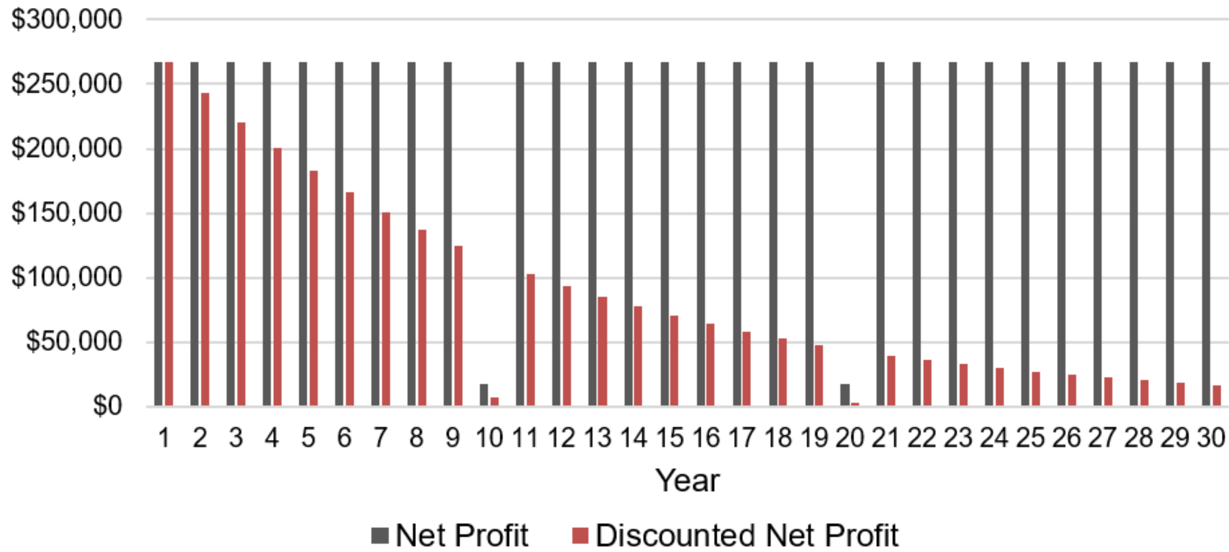

Figure 2. Annual net profit over the plant lifetime as modeled in the model, which optimizes operational variables only over a single year (values used are only an example; does not apply to Section 2.8).

1.6.1 Computational Environment

Results were computed by running a Python script, referred to as the optimizer in Section 1.2. The script called functions of the DISPATCHES package. To solve the mathematical model built by this script upon execution, a solver must be selected; the GNU Linear Programming Kit GLPK LP/MIP Solver v4.65 was used. The installed Institute for Design of Advanced Energy Systems' IDAES framework version was 2.0.0.dev3 with Pyomo Version 6.4.2. Using a single core (no parallelization) of an Intel(R) Core(TM) i7-1185G7 3.00GHz processor and 32 GB of installed random access memory, running the Windows 10 operating system, a typical run (one instance of a sensitivity study, also known as a subcase) took approximately 120 seconds.

1.7 Limitations

Simplifying assumptions may limit the model's accuracy, including:

- **Hourly resolution.** In Appendix B, where RTM LMP signals are used, the hourly resolution may alter the final optimized design and NPV because the averaged signal may smooth over potential price spikes within a given hour (as the RTM operates on a 5 minute interval).
- **Single-market sales.** The system did not have the flexibility to sell power into either the DAM or RTM within the same optimization run.
- **Linearization.** The physical behaviors of the model components are simplified from real-world operation. Specifically, the transfer functions of the electrolyzer, compressor, and fuel cell are taken to be linear, and the cost of storage is linear with respect to storage capacity.
- **Flat rate operating expenses for some components.** Some operating expenses were not scaled according to the size of the components—see Table 7 of Section 1.5.

An additional limitation of the case study approach is notable; the optimized dispatch decisions made in the model may not reflect real-life dispatch capabilities. This point will be more relevant in cases where the optimized solution includes frequent changes to the operational variables (flexible operation), while it will have no effect when near-constant operation is the optimal solution.

Finally, inflation is not accounted for. Price signals have not been inflated, even though discounting is integral to the NPV metric. This effect is not seen as significant, as an increase in the price signal will increase electricity revenues but also increase electricity costs, which are typically higher than electricity revenues due to the electricity-in, electricity-out system design (see Figure 1).

2. RESULTS

The results are organized by cases, with the base case presented first, followed by cases which are each a sensitivity study in two parameters. Before results are presented in detail, some remarks are made about the general nature of solutions.

Each instance of each sensitivity study (each run, also known as a subcase) resulted in a profitable solution (NPV > 0) or an unprofitable solution (NPV ≤ 0). Of the profitable solutions reached, almost all are one of two types: those where the HPTC is by far the largest source of revenue (HPTC dominant) and those where the capacity payment is by far the largest (CP dominant). These two types are a bifurcation in the results, visible as a sharp boundary in the color-coded tables of results (see Section 2.2). A small minority of profitable subcases lead to solutions not dominated by either source of revenue (e.g., HPTC more than half of CP but not more than double CP).

Naturally, many subcases are not profitable, with the optimal fuel cell capacity and tank storage both zero, and therefore there are no revenues and a zero NPV. Negative NPVs arose in subcases where installing additional electrolyzer capacity does not produce a profitable solution (see Section 2.3).

Each section below details the motivation for the case, followed by the results.

2.1 Base Case

We start by analyzing a base case using the nominal parameter values in Table 7, including the full HPTC rate of $3/kg and the estimated present-day CP rate of $2.5/kW-month. Table 8 shows the optimization results: a 0.365 MW fuel cell that is precisely sized to meet the full available production rate of the existing electrolyzer (21.081 kg/h). The storage tank size is 84.3 kg, equating to exactly 4 hours of hydrogen consumed by the fuel cell when operated at full power and thus meeting the minimum requirement for CPs. As the minimum amount of stored hydrogen must always be maintained, the stored level cannot decrease, and the tank acts as a pass-through component with no stored hydrogen available for energy arbitrage. Table 9 presents a full breakdown of line items contributing to the net profit, and Table 10 does the same for capital costs. The summation of net profit after discounting plus the discounted periodic replacement expenses led to the objective (NPV) as shown in Table 11. Figure 3 presents the capital expenditures and annual financials visually. The HPTC dominates revenue, making up 85% of total revenue—50× greater than the capacity payment revenue (<2%).

The operational variables are plotted in Figure 4, except for the stored mass of hydrogen, which did not vary. Electrolyzer power and fuel cell power remain at full power (1.0625 and 0.365 MW, respectively), except in several short periods when the power step-changes to zero. In every instance, both powers became zero simultaneously and later returned to full power simultaneously, as exemplified in Figure 5 and Figure 6, resulting in identical capacity factors for both the electrolyzer and fuel cell. The power-off events are found exclusively when the LMP is over $82/MWh, indicating that this price is the optimum cutoff to minimize electricity costs while maximizing HPTC revenue. The shutting down of the fuel cell during high electricity prices is counterintuitive but necessary due to the unavailability of excess hydrogen in the storage tank, which must maintain its full capacity to meet capacity market requirements. It can be assumed that the additional capital cost of an increased storage tank capacity, at $600/kg, is too high to be recuperated by selling electricity generated from excess hydrogen during the several spikes of the LMP above $82/MWh (if storage capacity above the minimum requirement were to be built).

Key Takeaways

- HPTC dominates the annual revenue, contributing 85%.
- Electricity is the major cost at 62% of the annual operating cost, while the fuel cell cost is 60% of the capital expenses, followed by the compressor at 31%.
- The fuel cell and electrolyzer operate continuously with few exceptions. During several periods with an LMP over $82/MWh, these components respond with an on-off operation: the electrolyzer and fuel cell both stopped operating.
    - The shutdown of the fuel cell during times of high prices can be explained by the lack of excess storage capacity, as the existing storage capacity only meets the minimum required to receive CPs (4 hours at full power). Presumably, high prices are not frequent enough in the price signal to offset the additional capital cost of a larger storage tank.

Table 8. Optimized design variables in the base case, along with the NPV and total capital expenditure.

Net Present Value	$1.362 M
Total Capital Expenditure	$0.606 M
Electrolyzer	
Capacity (electric)	*default (1.0625 MW)*
Capacity (mass flowrate of H_2)	21.081 kg/h
Capacity factor	0.993
Compressor	
Capacity (mass flowrate of H_2)	21.081 kg/h
Power draw at capacity	63.244 kW
Storage Tank	
Capacity	84.3 kg
Ratio of capacity over minimum required	1
Highest annual level	84.3 kg
Mean annual level	84.3 kg
Lowest annual level	84.3 kg
Fuel Cell	
Capacity (electric)	0.365 MW
Capacity (mass flowrate of H_2)	21.081 kg/h
Capacity factor	0.993

Table 9. Components of annual cash flow and annual net profit in the base case.

Electricity revenue	$	86,118
CPs	$	11,005
Electricity cost	$	(265,336)
Variable O&M expenses, excluding electricity cost	$	(6,357)
Fixed O&M expenses	$	(156,000)
Periodic replacement expenses		[1]—
Cash flow	$	(330,570)
Tax		—
HPTC	$	550,160
Net profit	$	219,590

[1] *See note at bottom of Table 11 for the treatment of periodic replacement expenses.*

Table 10. Capital expenditures in the base case.

Electrolyzer	$	—
Compressor	$	189,732
Storage tank	$	50,595
Fuel cell	$	365,374
Capital expenditures, total	$	605,701

Table 11. Summation of discounted net profit, replacement expenses, and capital costs to calculate NPV in the base case.

Discounted sum of annual net profit over plant life (30 years)[1]	$	2,070,058
Discounted sum of periodic replacement expenses (Years 10 and 20)	$	(102,213)
Capital expenditures, total	$	(605,701)
NPV	$	1,362,144

[1] *Periodic replacement expenses were not included in the annual net profit due to the nature of the single-year model but are included on the following line.*

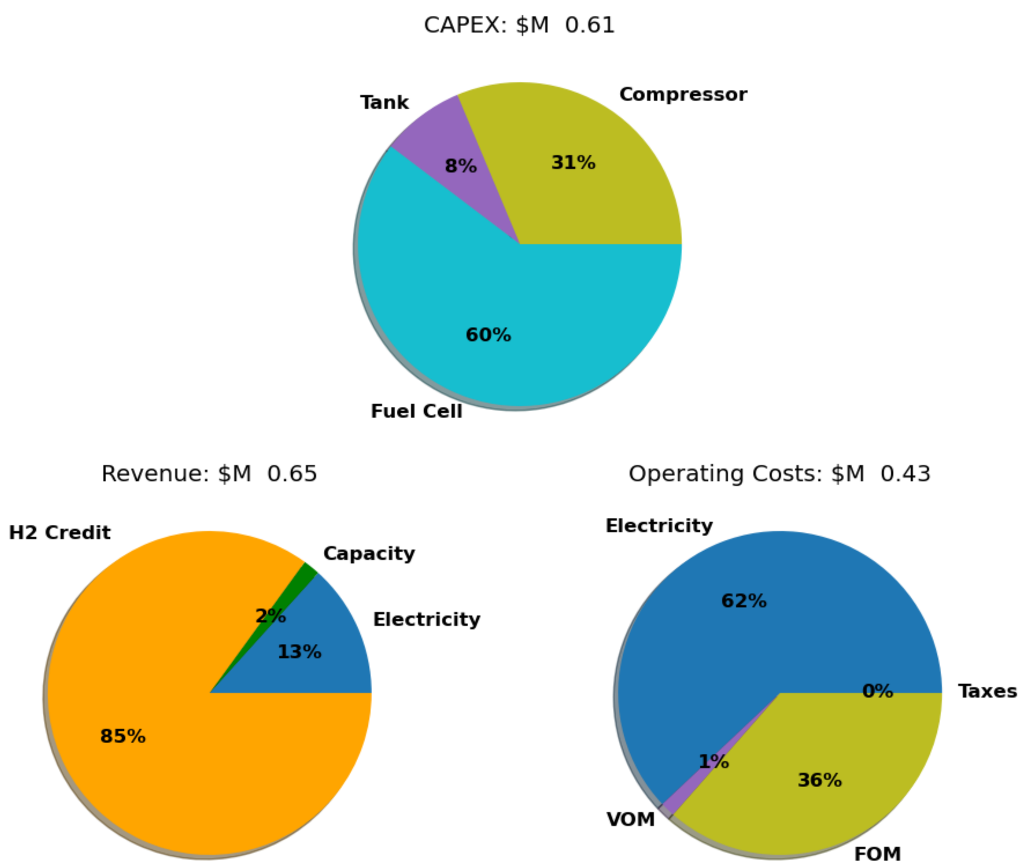

Figure 3. Pie charts showing the components of capital costs (CAPEX), operating costs including electricity, and revenues for the base case.

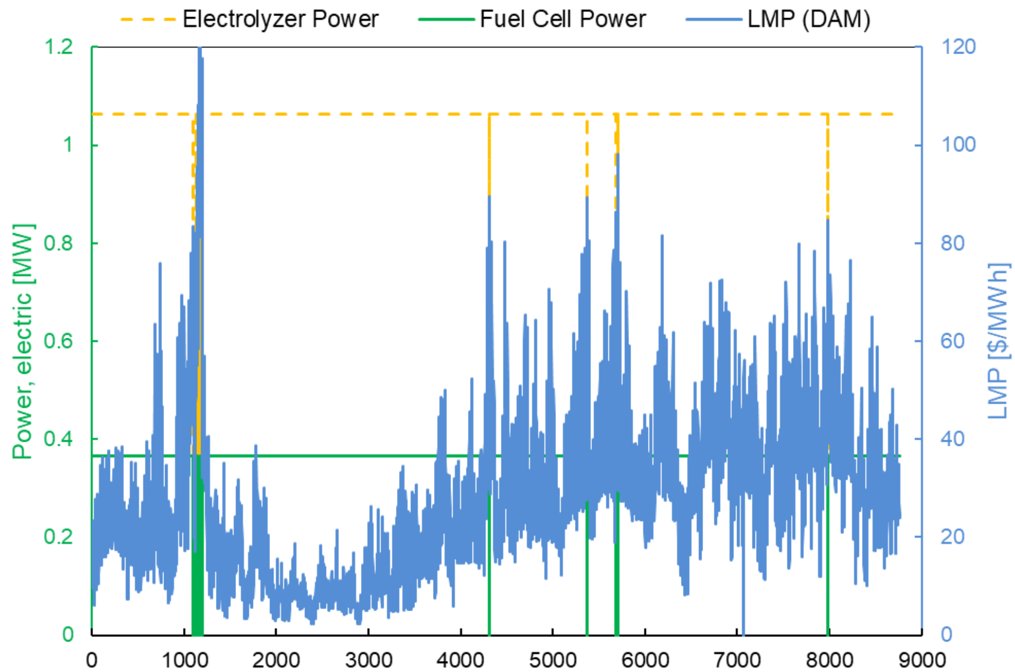

Figure 4. Hourly plot of electrolyzer power, fuel cell power, and price signal over the full year for the base case. Stored mass of H_2 did not vary and so is not shown.

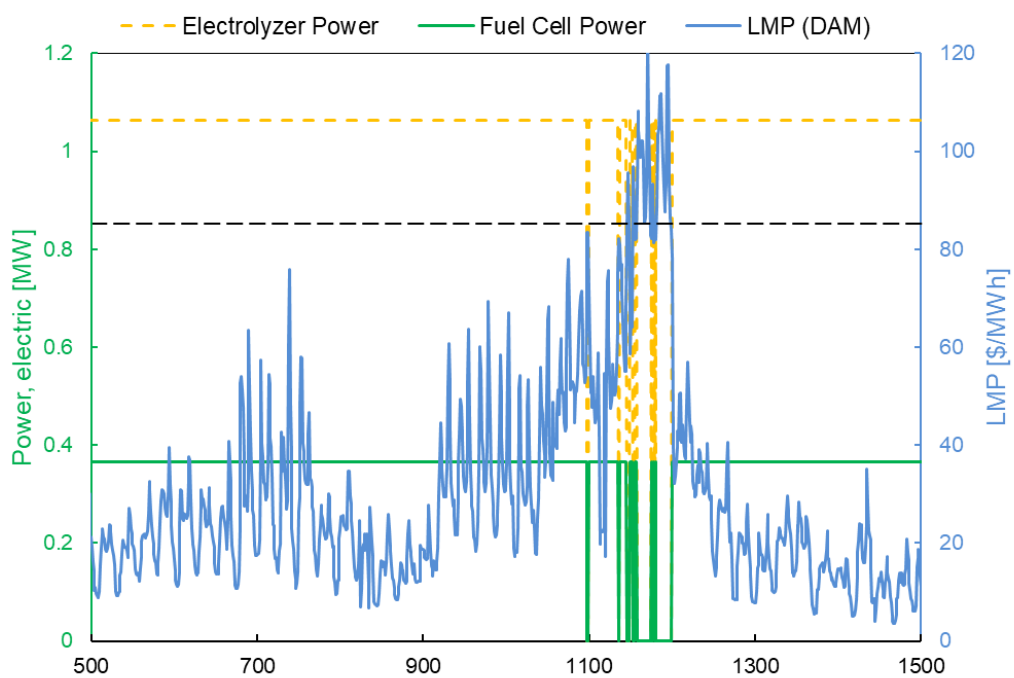

Figure 5. Detailed view of on-off events seen in Figure 4, where the black, dashed line represents the $82/MWh price level.

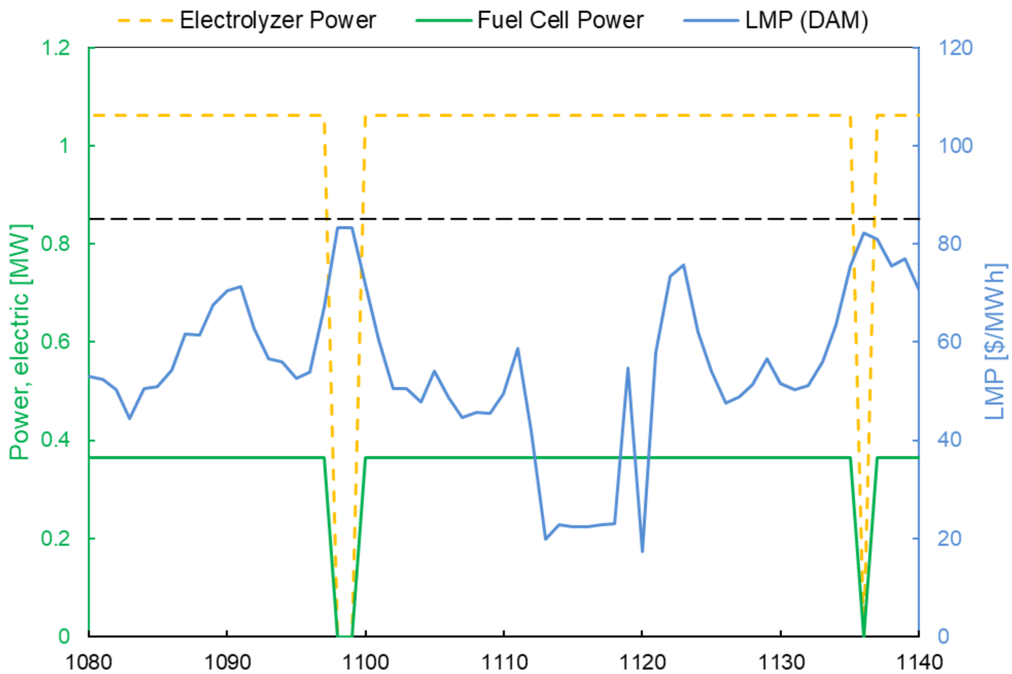

Figure 6. Detailed view of on-off events seen in Figure 5, where the black, dashed line represents the $82/MWh price level.

2.2 What Drives Revenue?

Next, we perform a sensitivity study by varying the HPTC and CP rates. Because HPTC and CP rates could vary depending on tax credit policy and capacity market policy, this sensitivity study varied these two rates and identified the driving revenue of each resulting solution. Starting from the default value of $2.5/kW-month, the CP was increased up to an aspirational level of $30/kW-month. The HPTC was decreased in steps of $0.5/kg, starting with its present maximum value of $3/kg [footnote g]. Results are presented in Table 12.

This case is also repeated with an increase in the capital expenditure to reflect the cost of building at an unprepared site and thus broaden the applicability of this specific industry study to more general circumstances. Appendix A shows results with increased capital expenditures.

Results

As seen in Table 12, the CP dominates at $15/kW-month and above, with no HPTC needed at $20/kW-month and above. Below $15/kW-month, an HPTC of $2.5/kg is needed to make the project profitable ($1.5/kg below $20/kW-month). Note that the continuation of tax credit throughout the project lifetime is a key assumption (see Section 2.8 for results with limited-time tax credits).

[g] Note that the HPTC may be graduated in other step sizes once implemented, such as multiples of $0.60 for the lowest-emitting producers.

Cases with both a low HPTC rate (below $2/kg) and present-day CP levels ($5 and below) are not profitable. With low HPTC rates of $1.5/kg and $1.0/kg, the CP must be $15 to make a profitable solution. For a zero HPTC or $0.5/kg HPTC rate, a CP of $20 is needed for profitability.

The boundary between the two profitable regions of the table was more closely approximated by running the case with finer steps in the CP rate, producing Table 13. The first subcase to have higher revenue from CP than from HPTC, moving from left to right, is at $13/kW-month and $2/kg, respectively; although, the subcase is still classified as neutral with a ratio between the revenues of 1.14. A subcase with light CP dominance (1.2 < ratio < 2) appears at $14/kW-month ($1.5/kg), and a subcase with full CP dominance (ratio ≥ 2) appears at $14.5/kW-month (also with $1.5/kg). Purely CP-dominant subcases are obtained with $15/kW-month. CP takes over as the main source of revenue between $14.5 and $15 per kW-month. Thus, the boundary between HPTC-dominant and CP-dominant regions may be said to be at the CP rate with a lightly HPTC-dominant and lightly CP-dominant case each: $14/kW-month. Multiple times larger fuel cells (over 10 MW) are incentivized from $15/kW-month (with HPTC).

Throughout the sensitivity study, the storage tank may be larger than the minimum required to satisfy the capacity market: the ratio of storage tank capacity to the minimum required (4 hours at full power) varies, rising as high as 1.75. Table 14 shows the ratio for each subcase.

HPTC-dominant subcases shift in their operational behavior, relative to the base case, as the CP rate increases. In the $3/kg, $10/kW-month case, the fuel cell cycles on and off more often (capacity factor of 0.58) while the electrolyzer continues to run nearly continuously with a capacity factor of 0.991. This may be explained though the CP incentivizing a larger fuel cell, which can then take greater advantage of variations in the LMP and matches with a larger optimal storage tank (1.73× the minimum). Figure 7 presents the capital expenditures and annual financials for the discussed subcase, and Figures 8 through 10 present the operational behavior.

In CP-dominant subcases, fuel cells are very large (10.7–11 MW, with a capacity to consume ~30× the H_2 production rate) and rarely operate (highest capacity factors are 0.034) or never operate. Although storage tanks are also very large (2,500–2,700 kg), their capacities are only 1–1.094× the minimum required to match the high-capacity fuel cells. The electrolyzer operates continuously for subcases with an HPTC of $3/kg, nearly continuously (capacity factors 0.96 and higher) for those with an HPTC from $1.5/kg to $2.5/kg, operates with capacity factors just under 0.8 for an HPTC of $1.0/kg, and does not operate at all for HPTC ≤ $0.5/kg. The total capital expenditure limit of $12,500,000 set by the industry partner is reached in all CP-dominant subcases, with the majority of the amount spent on the fuel cell (> 85%). As the majority of the revenue is no longer made up by a tax credit, the project becomes profitable from a tax standpoint and taxes are higher than electricity cost. Figure 11 presents the capital expenditures and annual financials for the HPTC = $3/kg, CP = $15/kW-month subcase, typical for CP-dominant subcases. Figures 12 through 14 present the operational behavior for the same subcase.

Key Takeaways

- Intermittent operation of the fuel cell is optimal only with a combination of elevated CP rates (around $10/kW-month) and high HPTC ($2.5-$3/kg), as indicated by intermediate capacity factors for those subcases.
- HPTC is the dominant source of revenue for CP rates up to and including $10/kW-month, while the CP is the dominant source of revenue for CP rates of $15/kW-month and above.
- When CP revenue is dominant, fuel cells are an order of magnitude larger (approaching 11 MW vs. 0.37 – 0.63 MW) and rarely operate (capacity factors of 0 – 0.034).

Results under nondefault price signals are presented and discussed in Appendix B, Section B-1.

Table 12. Summary of results for identification of driving revenue, with fuel cell capacity factors shown in parentheses. FC stands for fuel cell. Color-coding is defined in the legend.

HPTC [$/kg]	CP rate [$/kW-month]	2.51	5	10	15	20	30
0	NPV [$M]	0	0	0	0	3.66	12.45
	Tank [kg]	0	0	0	0	2534	2534
	FC [MW] (cap. fact.)	0	0	0	0	10.98 (0)	10.98 (0)
0.5	NPV [$M]	0	0	0	0	3.66	12.45
	Tank [kg]	0	0	0	0	2534	2534
	FC [MW] (cap. fact.)	0	0	0	0	10.98 (0)	10.98 (0)
1	NPV [$M]	0	0	0	0	4.05	12.67
	Tank [kg]	0	0	0	0	2625	2514
	FC [MW] (cap. fact.)	0	0	0	0	10.74 (0.027)	10.8 (0.026)
1.5	NPV [$M]	0	0	0	0.54	4.83	13.44
	Tank [kg]	0	0	0	2699	2644	2514
	FC [MW] (cap. fact.)	0	0	0	10.69 (0.033)	10.72 (0.033)	10.8 (0.033)
2	NPV [$M]	0	0	0	1.39	5.68	14.30
	Tank [kg]	0	0	0	2699	2644	2514
	FC [MW] (cap. fact.)	0	0	0	10.69 (0.034)	10.72 (0.034)	10.8 (0.034)
2.5	NPV [$M]	0.50	0.60	0.83	2.26	6.55	15.16
	Tank [kg]	84	84	246	2699	2644	2514
	FC [MW] (cap. fact.)	0.37 (0.985)	0.37 (0.985)	0.61 (0.587)	10.69 (0.034)	10.72 (0.034)	10.8 (0.034)
3	NPV [$M]	1.36	1.47	1.69	3.13	7.42	16.03
	Tank [kg]	84	84	250	2699	2644	2514
	FC [MW] (cap. fact.)	0.37 (0.993)	0.37 (0.993)	0.63 (0.578)	10.69 (0.034)	10.72 (0.034)	10.8 (0.034)

Hydrogen Production Tax Credit dominant (HPTC-d)

Capacity payment dominant (CP-d)

Revenues not sufficient for positive NPV (no-build)

Table 13. Results for identification of driving revenue with a finer step size in CP rate ($14.5/kW-month bolded due to irregular step size from other CP values). Fuel cell capacity factors are shown in parentheses.

HPTC [$/kg]		CP rate [$/kW-month] 11	12	13	14	**14.5**	15
0	NPV [$M]	0	0	0	0	0	0
	Tank [kg]	0	0	0	0	0	0
	FC [MW]	0	0	0	0	0	0
0.5	NPV [$M]	0	0	0	0	0	0
	Tank [kg]	0	0	0	0	0	0
	FC [MW]	0	0	0	0	0	0
1	NPV [$M]	0	0	0	0	0	0
	Tank [kg]	0	0	0	0	0	0
	FC [MW]	0	0	0	0	0	0
1.5	NPV [$M]	0	0	0	0.06	0.16	0.54
	Tank [kg]	0	0	0	734	949	2699
	FC [MW] (cap. fact.)	0	0	0	2.36 (0.147)	3.29 (0.107)	10.69 (0.033)
2	NPV [$M]	0.10	0.41	0.69	0.91	1.01	1.39
	Tank [kg]	590	909	833	763	949	2699
	FC [MW] (cap. fact.)	1.64 (0.21)	2.93 (0.121)	2.7 (0.133)	2.48 (0.146)	3.29 (0.11)	10.69 (0.034)
2.5	NPV [$M]	0.94	1.27	1.55	1.78	1.88	2.26
	Tank [kg]	632	930	845	770	991	2699
	FC [MW] (cap. fact.)	1.83 (0.197)	3.03 (0.12)	2.75 (0.132)	2.52 (0.145)	3.47 (0.105)	10.69 (0.034)
3	NPV [$M]	1.80	2.13	2.42	2.65	2.75	3.13
	Tank [kg]	632	937	849	773	991	2699
	FC [MW] (cap. fact.)	1.83 (0.199)	3.06 (0.119)	2.77 (0.132)	2.53 (0.144)	3.47 (0.105)	10.69 (0.034)

Hydrogen Production Tax Credit dominant (HPTC-d)
Capacity payment dominant (CP-d)
Revenues not sufficient for positive NPV (no-build)

Light HPTC-d (0.5 < CP:HPTC < 0.8)
Light CP-d (1.2 < CP:HPTC < 2)
Neutral (0.8 < CP:HPTC < 1.2)

Table 14. Ratio of storage tank capacity over minimum required for capacity market. Color coding is as in Table 12.

HPTC [$/kg] \ CP [$/kW-month]	2.5	5	10	15	20	30
0	—	—	—	—	1	1
0.5	—	—	—	—	1	1
1	—	—	—	—	1.060	1.008
1.5	—	—	—	1.094	1.068	1.008
2	—	—	—	1.094	1.068	1.008
2.5	1	1	1.750	1.094	1.068	1.008
3	1	1	1.729	1.094	1.068	1.008

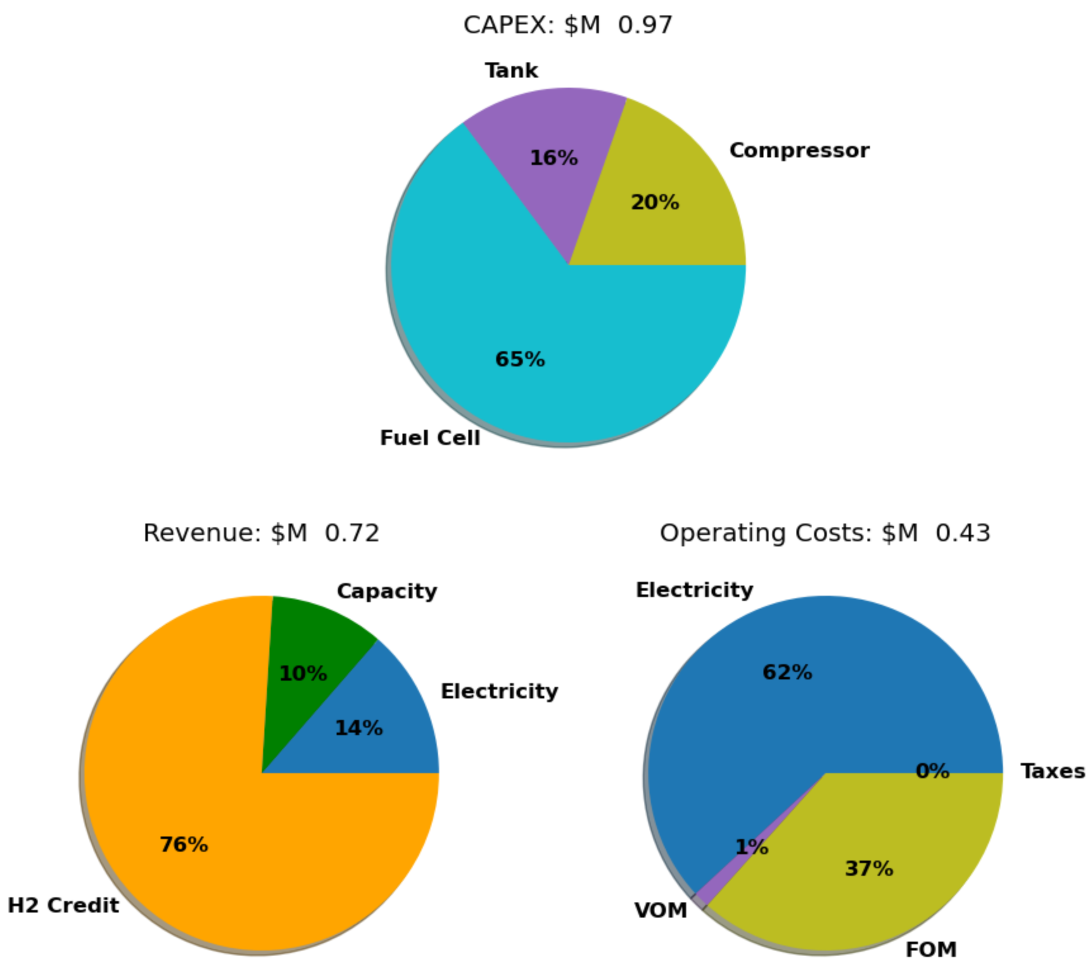

Figure 7. Pie charts showing the components of capital costs (CAPEX), operating costs including electricity, and revenues for the HPTC = $3/kg, CP = $10/kW-month subcase.

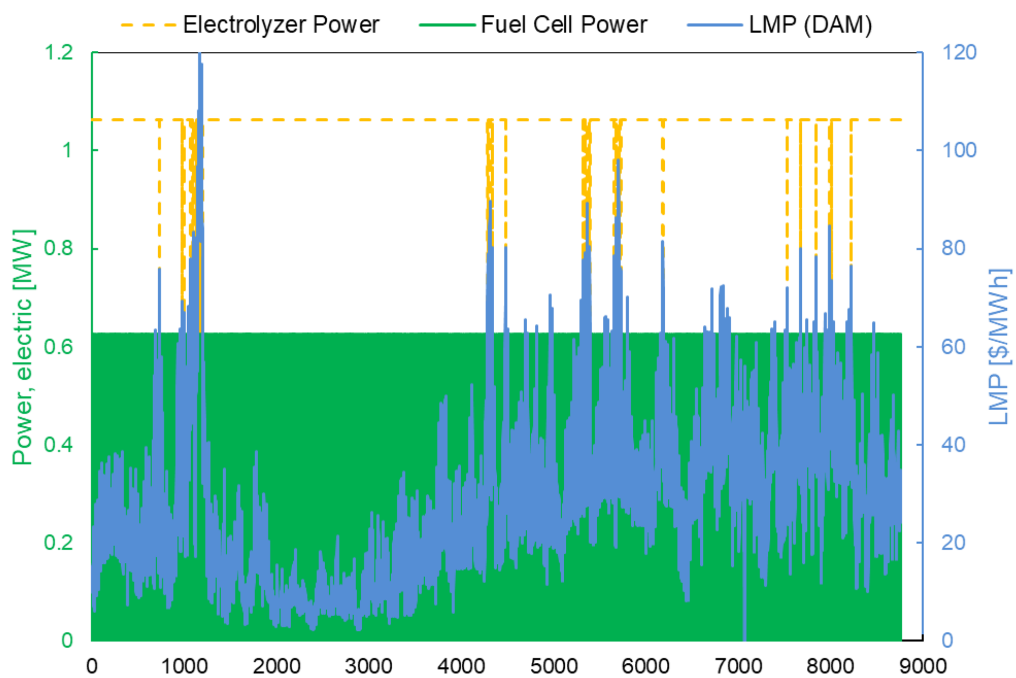

Figure 8. Hourly plot of electrolyzer power, fuel cell power, and price signal over the full year for an HPTC-dominant solution near the border between regions in Table 12 ($3/kg, $10/kW-month subcase).

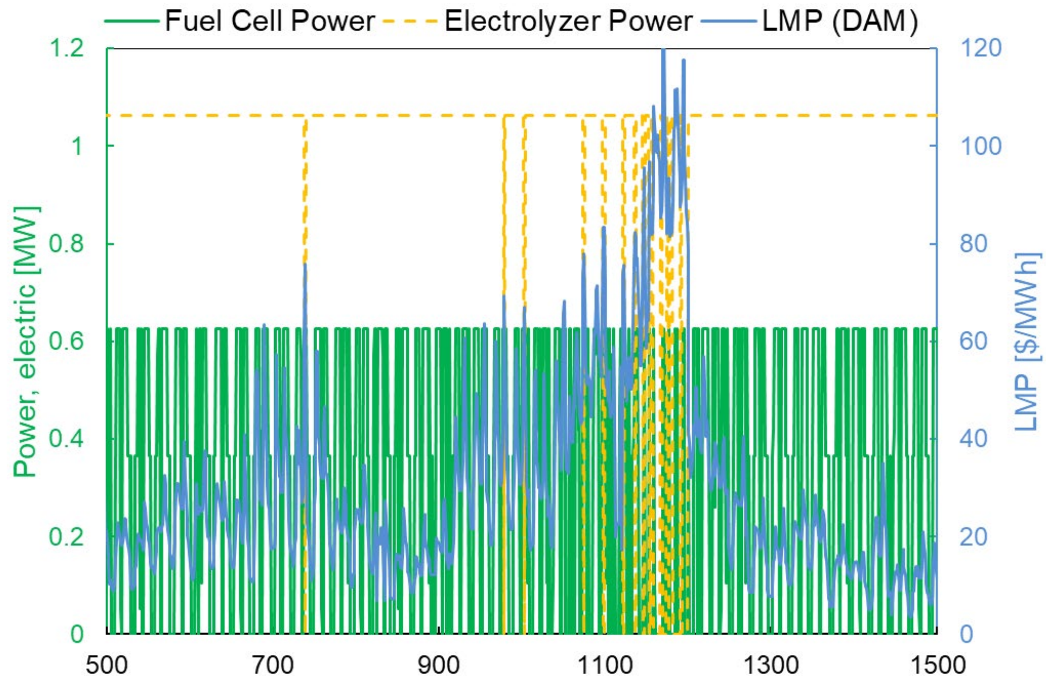

Figure 9. Detailed view of power changes seen in Figure 8 (HPTC-dominant subcase: $3/kg, $10/kW month).

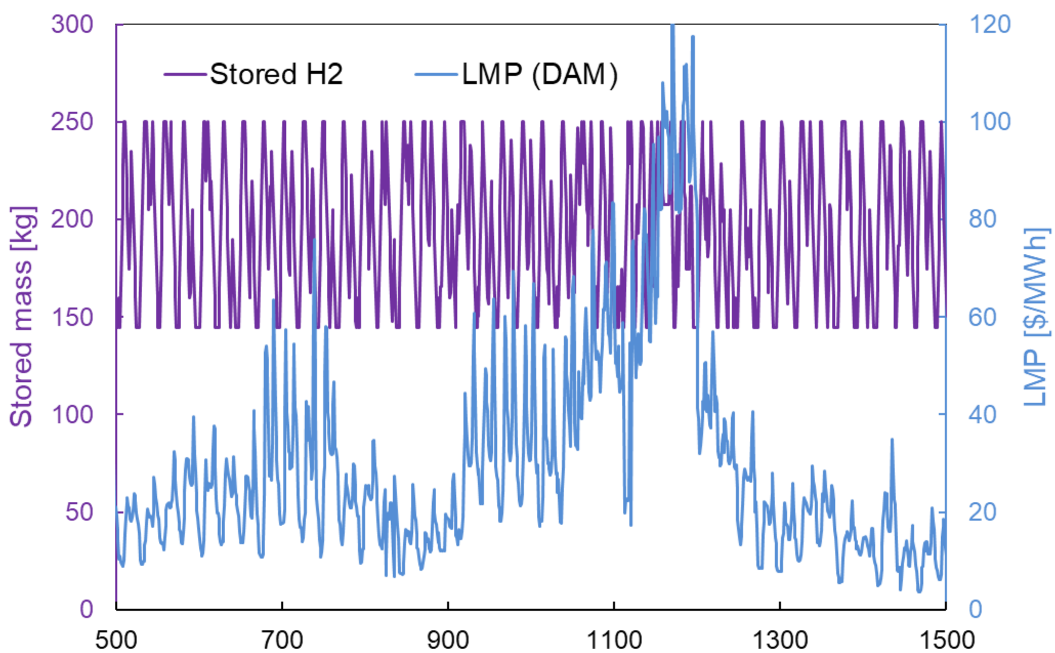

Figure 10. Plot of stored mass of H2, matching the time window of Figure 9 (HPTC-dominant subcase: $3/kg, $10/kW month).

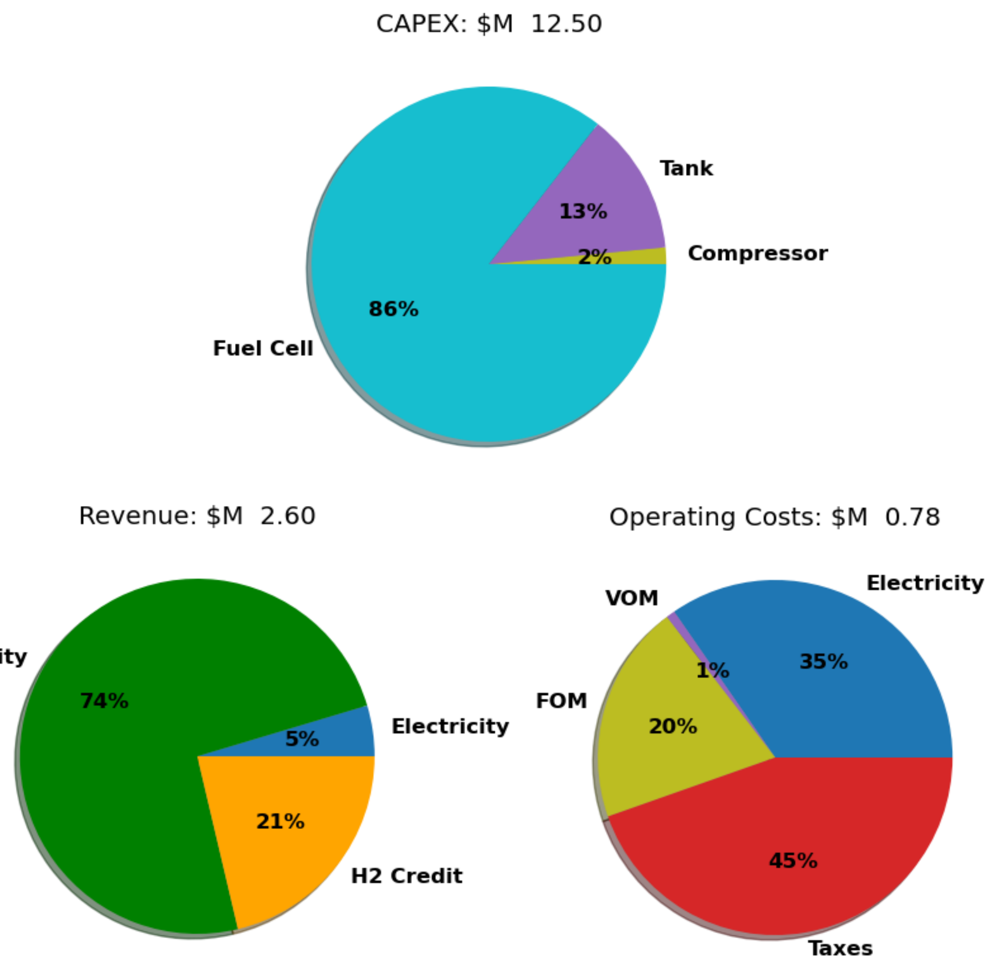

Figure 11. Pie charts showing the components of capital costs (CAPEX), operating costs including electricity, and revenues for the HPTC = \$3/kg, CP = \$15/kW-month subcase.

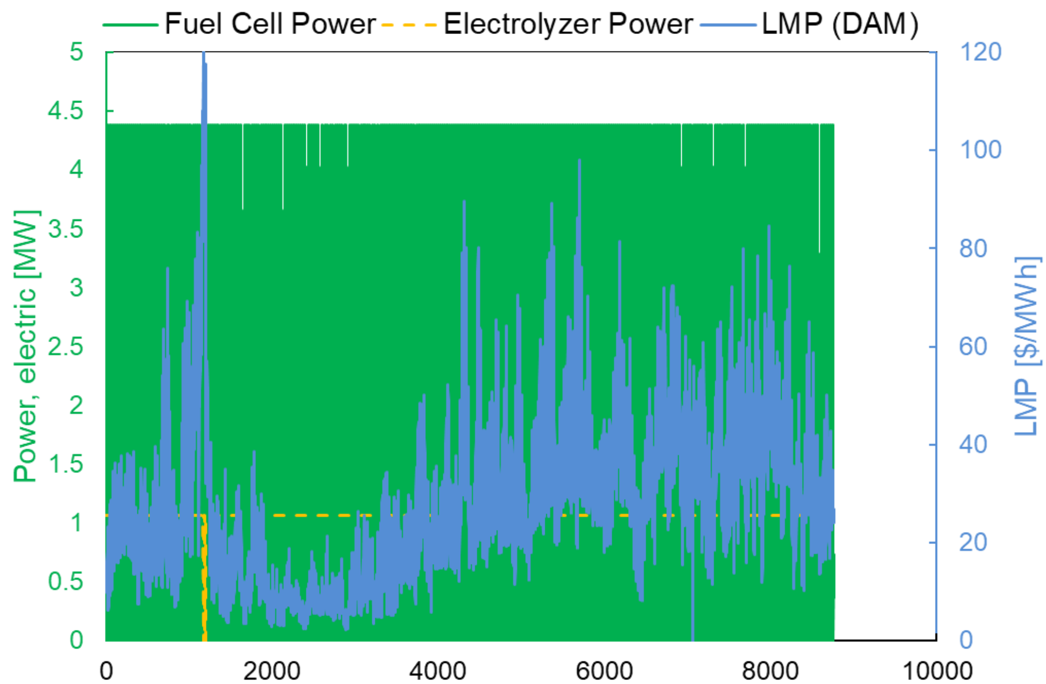

Figure 12. Hourly plot of electrolyzer power, fuel cell power, and price signal over the full year for a CP-dominant solution ($3/kg, $15/kW-month subcase).

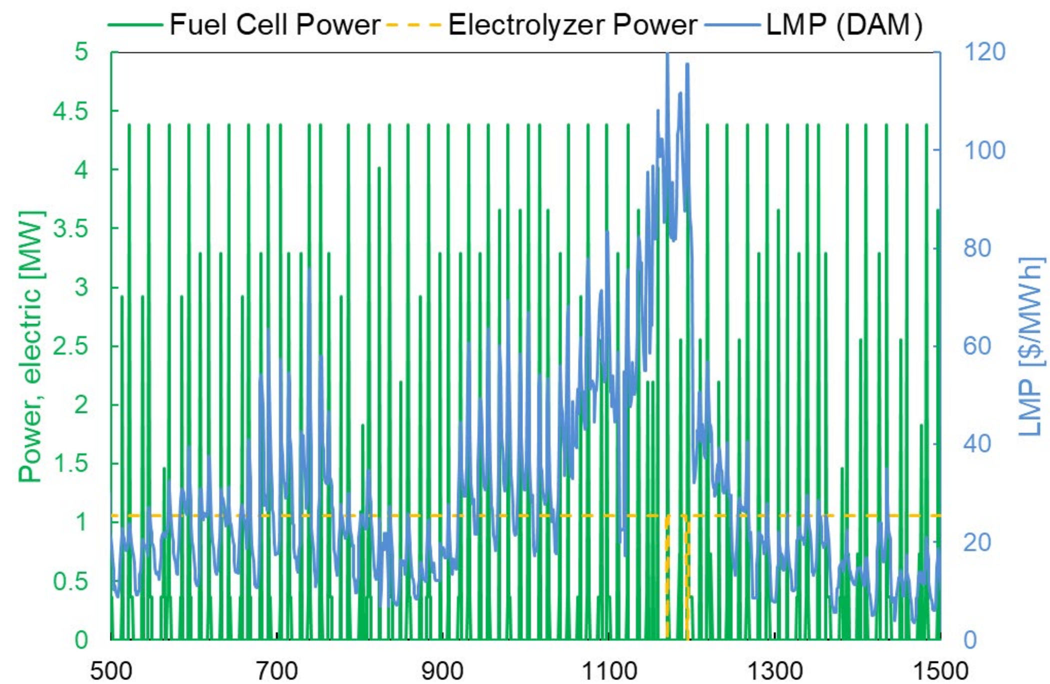

Figure 13. Detailed view of power changes seen in Figure 12 (CP-dominant subcase: \$3/kg, \$15/kW-month).

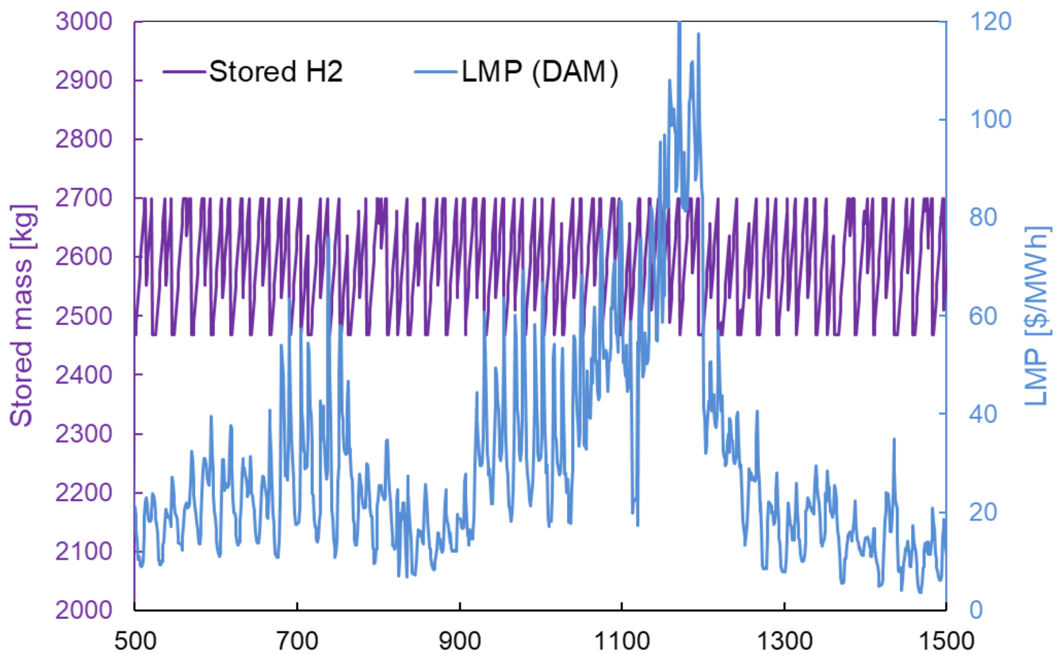

Figure 14. Plot of stored mass of H_2, matching the time window of Figure 13 (CP-dominant subcase: \$3/kg, \$15/kW-month).

2.3 Effect of Added Electrolyzer Capacity

Results for the addition of electrolyzer capacity to the standard sensitivity study of Section 2.2 are shown in Table 15 and Table 16, for 1 and 2 MW of added capacity, respectively. These additions were considered due to the dominance of HPTC revenue in the base case—adding the electrolyzer capacity makes the maximum possible tax credit higher and so can increase the NPV. As the electrolyzer capacity is not an optimized variable, it was added in fixed increments, while repeating the sensitivity study of Section 2.2.

Results

The HPTC is the driver for the profitable addition of electrolyzer capacity. Increases from the present capacity to +1 MW, and from +1 MW to +2 MW, are only profitable when the HPTC rate is $2/kg and higher. At $1/kg, the additional electrolyzer capacity decreases the NPV.

The boundary between CP- and HPTC-dominant regions shifts to increase the HPTC-dominant region with an additional electrolyzer capacity above the +1 MW level, as seen for the $15/kW-month set. At an HPTC rate of $3/kg, the lightly CP-dominant subcase at +1 MW becomes neutral at +2 MW (neither revenue is dominant) and two subcases become only lightly CP dominant; at an HPTC rate of $2/kg, two subcases also become lightly CP-dominant. Notably, the shift to the +2 MW level *in*creases the optimal fuel cell capacity where the HPTC dominates but *de*creases optimal fuel cell capacity where the CP dominates.

Negative NPVs correspond to unprofitable solutions because the capital expense of the added electrolyzer cells is prescribed and therefore included in the NPV calculation.

Key Takeaways

- Adding electrolyzer capacity is warranted only for HPTC-dominant cases (when the CP rate is $10/kW-month or less) and only when the HPTC is $2/kg and above.

Table 15. Summary of results with 1 MW of additional electrolyzer capacity, with fuel cell capacity factors shown in parentheses.

Electrolyzer + 1 MW			CP rate [$/kW-month]					
			2.51	5	10	15	20	30
HPTC [$/kg]	0	NPV [$M]	-1.45	-1.45	-1.45	-1.45	2.05	10.14
		Tank [kg]	0	0	0	0	2331	2331
		FC [MW] (cap. fact.)	0	0	0	0	10.1 (0)	10.1 (0)
	1	NPV [$M]	-1.45	-1.45	-1.45	-1.04	2.80	10.55
		Tank [kg]	0	0	0	2616	2508	2293
		FC [MW] (cap. fact.)	0	0	0	9.56 (0.06)	9.63 (0.059)	9.76 (0.057)
	2	NPV [$M]	-0.67	-0.47	-0.03	2.14	5.97	13.72
		Tank [kg]	245	246	513	2652	2544	2293
		FC [MW] (cap. fact.)	0.71 (0.931)	0.71 (0.93)	1.16 (0.572)	9.54 (0.074)	9.61 (0.073)	9.76 (0.072)
	3	NPV [$M]	2.63	2.83	3.26	5.51	9.34	17.09
		Tank [kg]	164	164	485	2652	2544	2293
		FC [MW] (cap. fact.)	0.71 (0.993)	0.71 (0.993)	1.22 (0.578)	9.54 (0.074)	9.61 (0.074)	9.76 (0.073)

- Hydrogen Production Tax Credit dominant (HPTC-d)
- Capacity payment dominant (CP-d)
- Revenues not sufficient for positive NPV (no-build)

- Light HPTC-d (0.5 < CP:HPTC < 0.8)
- Light CP-d (1.2 < CP:HPTC < 2)
- Neutral (0.8 < CP:HPTC < 1.2)

Table 16. Summary of results with 2 MW of additional electrolyzer capacity, with fuel cell capacity factors shown in parentheses.

Electrolyzer +2 MW		**CP rate [$/kW-month]**					
HPTC [$/kg]		2.51	5	10	15	20	30
0	NPV [$M]	-2.90	-2.90	-2.90	-2.90	0.45	7.83
	Tank [kg]	0	0	0	0	2129	2129
	FC [MW] (cap. fact.)	0	0	0	0	9.22 (0)	9.22 (0)
1	NPV [$M]	-2.90	-2.90	-2.90	-1.85	1.55	8.44
	Tank [kg]	0	0	0	2448	2391	2071
	FC [MW] (cap. fact.)	0	0	0	8.48 (0.099)	8.52 (0.098)	8.71 (0.094)
2	NPV [$M]	-1.00	-0.71	-0.05	2.86	6.26	13.14
	Tank [kg]	364	365	762	2498	2396	2071
	FC [MW] (cap. fact.)	1.05 (0.931)	1.05 (0.93)	1.72 (0.572)	8.45 (0.124)	8.52 (0.123)	8.71 (0.12)
3	NPV [$M]	3.89	4.19	4.83	7.86	11.27	18.15
	Tank [kg]	243	243	720	2498	2396	2071
	FC [MW] (cap. fact.)	1.05 (0.993)	1.05 (0.993)	1.81 (0.578)	8.45 (0.125)	8.52 (0.124)	8.71 (0.121)

2.4 Exploring Prescribed Fuel Cell Capacity on the Order of Megawatts Together with Additional Electrolyzer Capacity

Results for various combinations of electrolyzer and fuel cell capacities, while otherwise preserving the base case, are shown in Table 17. As the base case optimal capacity of 0.365 MW was less than may be typically installed, the study team considered fuel cell capacities on the order of megawatts. Simultaneously, the team questioned whether larger fuel cell capacity would be profitable without larger electrolyzer capacity. To address these concerns, this section presents combinations of prescribed fuel cell capacity and prescribed electrolyzer capacity. For simplicity, the optimization runs in this section kept all other default (base case) parameter values, resulting in a single set of results with two varied parameters: electrolyzer capacity and fuel cell capacity. Fuel cell capacity, which was optimized in the previously presented cases, was prescribed at fixed values for three other levels (columns) but was also optimized only in one set of subcases (one column[h]).

Results

Imposing an increase in the fuel cell capacity decreases the NPV while increasing the storage tank capacity. Alternatively, adding 1 MW of electrolyzer capacity increases the NPV and optimal storage tank and fuel cell capacities, with a further increase when adding 2 MW. Capacity factors are high for fuel cells with capacities much smaller than the electrolyzer capacity, in keeping with the steady-state ratio between the two capacities of 1:0.365 found in the base case (whereby the rates of hydrogen production and consumption are equal when the system is operated at full power). Other combinations below a diagonal running from the top-left to the bottom-right corner of Table 17 also have capacity factors greater than 0.5, while those above it see progressively lower capacity factors as the top-right corner (low electrolyzer, high fuel cell) is approached.

Under the default assumptions used for this section (full HPTC of $3/kg and typical present-day CP rate of $2.5/kW-month), the most profitable choice is adding 2 MW of electrolyzer capacity with an optimal fuel cell size of approximately 1 MW. Presumably, a further increase in the electrolyzer capacity would give yet a higher NPV, provided sufficient budget, albeit with greater exposure to risk given the increased capital investment.

Table 17. Overview of results for each of three each of three fixed fuel cell capacities when paired with fixed electrolyzer capacities, as well as for combinations with unrestricted (optimized) fuel cell capacity (present electrolyzer capacity is 1.0625 MW). FC stands for fuel cell.

			Fuel cell capacity			
			Optimal	1 MW	2 MW	5 MW
Electrolyzer capacity	Present	NPV [$M]	1.36	0.83	-0.12	-3.06
		Tank [kg]	84	378	672	1421
		FC [MW]	0.365	1	2	5
	+1 MW	NPV [$M]	2.63	2.41	1.53	-1.34
		Tank [kg]	164	382	759	1604
		FC [MW]	0.709	1	2	5
	+2 MW	NPV [$M]	3.89	3.59	3.14	0.35
		Tank [kg]	243	346	802	1762
		FC [MW]	1.053	1	2	5

[h] Although the first column repeats previous results, this column is maintained to allow comparison within this set of results.

Key Takeaways

- Adding 2 MW of electrolyzer capacity with an optimal fuel cell size of approximately 1 MW is the most profitable option of those considered when under default HPTC and CP rates of $3/kg and $2.5/kW-month.
  - By extrapolation, adding further electrolyzer capacity beyond +2 MW would be yet more profitable (although presumably with associated higher risk due to higher capital cost).
- A future decision by the tax authority to account for the HPTC upon production of hydrogen versus upon its use for electrical generation does not impact the economics of the system.

Results under nondefault price signals are presented and discussed in Appendix B, Section B-2.

2.5 Effect of Fuel Cell Capital Cost

This section explores changes in the fuel cell capital cost rate, with four nondefault levels. As future changes in the cost of fuel cells are likely, it is reasonable to consider the impact of lower and higher fuel cell costs. Changes in the capital cost of the fuel cell (per unit capacity) of -50%, -30%, -15%, and +25% were used. Each set of results is a repetition of the sensitivity study of Section 2.2, except for nondefault fuel cell cost. Results are shown in Table 18 and Table 19.

Results

While HPTC-dominant subcases are only modestly impacted in their NPV and fuel cell capacity, CP-dominant solutions see significant increases in NPV and fuel cell capacity for reduced capital cost (decreases in the case of higher capital cost).

Compared to results for the default fuel cell capital cost (Section 2.2), the NPV values of HPTC-dominant subcases increased by 4%, 7.5%–8%, and 13% at reduced fuel cell capital cost levels of -15%, -30%, and -50%, respectively, while fuel cell and storage tank capacities remained the same (with exception of two subcases: $3/kg–$10/kW-month, and at -50% only, $3/kg–$10/kW-month). Reduced capital cost levels expand the CP-dominant region largely by turning unprofitable subcases to profitable subcases (compare to Section 2.2). Subcases with low HPTC rates of zero and $1/kg become profitable at $15/kW-month for all reduced capital cost levels. At the -50% capital cost level, a CP rate of $10/kW-month becomes profitable without HPTC. The contribution of CP also becomes more significant outside of the CP-dominant region, with a lightly HPTC-dominant result replacing a HPTC-dominant result at intermediate reduced capital levels (light orange at $3/kg–$10/kW-month in the -15% and -30% tables) and switching to CP dominant at the -50% level. For $3/kg–$10/kW-month, the design of the system is drastically altered at the -50% level because the solution becomes CP dominant.

If fuel cell capital cost increases by 25%, the minimum CP level for CP-dominant solutions under all HPTC levels is raised by one step to $20, and the NPVs and fuel cell sizes of all CP-dominant solutions decline significantly (NPV by 27%–80%, fuel cell capacities by 18% for all but lightly dominant cases). HPTC-dominant subcases see only a slight decline in NPV (6–7%) and no change in design except for the $10/kW-month, $3/kg subcase.

Key Takeaways

- Reduced fuel cell capital cost modestly, linearly increases NPVs, by 4% for a -15% change in fuel cell costs and by 13% for a -50% change in fuel cell cost.
- Reduced fuel cell costs can turn several subcases at low or no HPTC profitable at intermediate CP rates ($10–$15/kW-month). Larger decreases in cost lower the needed CP rate: while -15% lowers the needed CP rate to $15/kW-month from $20/kW-month (needed at default fuel cell cost), a -50% change lowers the needed rate to $10/kW-month.

Results under nondefault price signals are presented and discussed in Appendix B, Section B-3.

Table 18. Summary of results with fuel cell capital cost rate lowered by 50% and 30%.

FC CAPEX $500 (-50%)

HPTC [$/kg]		CP rate [$/kW-month] 2.51	5	10	15	20	30
0	NPV [$M]	0	0	0.61	8.44	16.28	31.95
	Tank [kg]	0	0	4518	4518	4518	4518
	FC [MW]	0	0	19.578	19.578	19.578	19.578
1	NPV [$M]	0	0	1.06	8.73	16.43	31.95
	Tank [kg]	0	0	4598	4516	4450	4518
	FC [MW]	0	0	19.102	19.201	19.281	19.578
2	NPV [$M]	0	0	2.70	10.36	18.06	33.49
	Tank [kg]	0	0	4615	4516	4450	4450
	FC [MW]	0	0	19.083	19.201	19.281	19.281
3	NPV [$M]	1.54	1.65	4.44	12.10	19.80	35.23
	Tank [kg]	84	173	4615	4516	4450	4450
	FC [MW]	0.365	0.475	19.083	19.201	19.281	19.281

FC CAPEX $700 (-30%)

HPTC [$/kg]		CP rate [$/kW-month] 2.51	5	10	15	20	30
0	NPV [$M]	0	0	0	3.46	9.43	21.36
	Tank [kg]	0	0	0	3441	3441	3441
	FC [MW]	0	0	0	14.908	14.908	14.908
1	NPV [$M]	0	0	0	3.85	9.69	21.44
	Tank [kg]	0	0	0	3512	3441	3388
	FC [MW]	0	0	0	14.576	14.636	14.682
2	NPV [$M]	0	0	0.71	5.48	11.32	23.07
	Tank [kg]	0	0	1008	3529	3459	3388
	FC [MW]	0	0	3.453	14.561	14.621	14.682
3	NPV [$M]	1.47	1.57	2.44	7.22	13.06	24.80
	Tank [kg]	84	84	1028	3529	3459	3388
	FC [MW]	0.365	0.365	3.539	14.561	14.621	14.682

Hydrogen Production Tax Credit dominant (HPTC-d)

Capacity payment dominant (CP-d)

Revenues not sufficient for positive NPV (no-build)

Light HPTC-d (0.5 < CP:HPTC < 0.8)

Light CP-d (1.2 < CP:HPTC < 2)

Table 19. Summary of results with fuel cell capital cost rate lowered by 15% and increased by 25%.

FC CAPEX $850 (-15%) — CP rate [$/kW-month]

HPTC [$/kg]		2.51	5	10	15	20	30
0	NPV [$M]	0	0	0	1.05	6.11	16.23
	Tank [kg]	0	0	0	2919	2919	2919
	FC [MW]	0	0	0	12.646	12.646	12.646
1	NPV [$M]	0	0	0	1.49	6.44	16.39
	Tank [kg]	0	0	0	3037	2983	2874
	FC [MW]	0	0	0	12.339	12.377	12.454
2	NPV [$M]	0	0	0.20	3.13	8.07	18.01
	Tank [kg]	0	0	1038	3037	2983	2874
	FC [MW]	0	0	3.495	12.339	12.377	12.454
3	NPV[$M]	1.42	1.52	1.91	4.86	9.81	19.75
	Tank [kg]	84	84	1087	3037	2983	2874
	FC [MW]	0.365	0.365	3.704	12.339	12.377	12.454

FC CAPEX $1250 (+25%) — CP rate [$/kW-month]

HPTC [$/kg]		2.51	5	10	15	20	30
0	NPV [$M]	0	0	0	0	0.76	7.97
	Tank [kg]	0	0	0	0	2078	2078
	FC [MW]	0	0	0	0	9.003	9.003
1	NPV [$M]	0	0	0	0	1.21	8.26
	Tank [kg]	0	0	0	0	2217	2122
	FC [MW]	0	0	0	0	8.784	8.830
2	NPV [$M]	0	0	0	0.56	2.85	9.89
	Tank [kg]	0	0	0	757	2217	2141
	FC [MW]	0	0	0	2.368	8.784	8.820
3	NPV [$M]	1.27	1.37	1.58	2.29	4.59	11.63
	Tank [kg]	84	84	84	774	2217	2141
	FC [MW]	0.365	0.365	0.365	2.441	8.784	8.820

Hydrogen Production Tax Credit dominant (HPTC-d)

Capacity payment dominant (CP-d)

Revenues not sufficient for positive NPV (no-build)

Light HPTC-d (0.5 < CP:HPTC < 0.8)

Light CP-d (1.2 < CP:HPTC < 2)

2.6 HPTC Earned Upon Use of Hydrogen, Rather Than Upon Production

When the same subcases presented in Section 2.4 were run with the HPTC revenue credited on use of the hydrogen at the fuel cell, rather than on its production, results were unchanged. All results presented in this report were generated with crediting of the HPTC revenue upon production of hydrogen.

2.7 Impact of Partial Loss of Zero-Emission Nuclear Power Production Credit

This section investigates the possibility of partial loss of revenue from the ZNPPC as a result of the system layout: as the electrolyzer draws electricity, electric power is diverted from the grid. Thus, it is possible that the tax authority will consider the relevant amount of electric power ineligible for the ZNPPC. Even if the electric power generated by the fuel cell is eligible for the ZNPPC, the result would be a net decrease in the ZNPPC revenue earned from the whole of the NPP and hydrogen-based integrated energy system (due to conversion losses, only a fraction of the power used by the electrolyzer can be supplied to the grid by the fuel cell).

Although the NPP is not considered in the system model, a loss of ZNPPC revenue at the NPP was included by counting a cost per unit electric energy ($15/MWh) used by the electrolyzer, representing an opportunity cost. A further ZNPPC revenue was also be earned per unit electric energy ($15/MWh) generated by the fuel cell. Results for the sensitivity study as conducted in Section 2.2, with consideration of the ZNPPC added as just described, are shown in Table 21.

Results

Table 20 gives components of cash flow under default HPTC and CP rates when the ZNPPC is treated, while Table 21 gives results of the HPTC-CP sensitivity study with ZNPPC included. Loss of electricity production tax credit at the NPP, as an opportunity cost, significantly decreases the NPV of all profitable HPTC-dominant subcases. NPVs drop by 50%–63%. CP-dominant subcases see more modest decreases, as high as 28% at lower HPTC rates and higher CP rates, with subcases at zero HPTC unchanged. The system design is virtually unchanged (design variables change < 3%).

Key Takeaways

- If an option to earn ZNPPC for electric power produced at the fuel cell is available, but is tied to a loss of a tax credit at the same rate ($/MWh) at the NPP, accepting such an arrangement would significantly decrease profitability. Results for this scenario are presented here.
- NPV decreased by 63% when the $15/MWh ZNPPC was applied to the base case (result for $3/kg–$2.5/kW-month in Table 21 vs. Table 12).
    - By extrapolation, if the loss of ZNPPC for each unit of electric power produced at the NPP and sent to the electrolyzer cannot be avoided, and the ZNPPC does not apply to electric power produced at the fuel cell, the same conclusion would be reached: profitability would decrease even more significantly.

Table 20. Components of annual cash flow and annual net profit when ZNPPC is included, under the default HPTC rate of $3/kg and default CP rate of $2.5/kW-month.

Electricity revenue	$	84,745
CPs	$	11,188
Electricity cost	$	(250,453)
Variable O&M cost, excluding electricity cost	$	(6,208)
Fixed O&M cost	$	(156,000)
Periodic replacement expenses		*-
Cash Flow	$	(316,727)
Tax		-
HPTC	$	537,292
Zero-Emission Nuclear Power Production Tax Credit	$	(88,837)
Net Profit	$	131,728

**Periodic replacement expenses were not included in the annual net profit due to the nature of the single-year model.*

Table 21. Results with partial loss of Zero-Emission Nuclear Power Production Credit considered, with fuel cell capacity factors shown in parentheses.

ZNPPC with opportunity cost

HPTC [$/kg]		CP rate [$/kW-month] 2.51	5	10	15	20	30
0	NPV [$M]	0	0	0	0	3.66	12.45
	Tank [kg]	0	0	0	0	2534	2534
	FC [MW] (cap. fact.)	0	0	0	0	10.98 (0)	10.98 (0)
1	NPV [$M]	0	0	0	0	3.66	12.45
	Tank [kg]	0	0	0	0	2534	2534
	FC [MW] (cap. fact.)	0	0	0	0	10.98 (0)	10.98 (0)
2	NPV [$M]	0	0	0	0.55	4.83	13.45
	Tank [kg]	0	0	0	2699	2644	2514
	FC [MW] (cap. fact.)	0	0	0	10.69 (0.033)	10.72 (0.033)	10.8 (0.033)
3	NPV [$M]	0.51	0.61	0.84	2.27	6.56	15.17
	Tank [kg]	84	84	246	2699	2644	2514
	FC [MW] (cap. fact.)	0.37 (0.985)	0.37 (0.985)	0.61 (0.587)	10.69 (0.034)	10.72 (0.034)	10.8 (0.034)

Hydrogen Production Tax Credit dominant (HPTC-d)

Capacity payment dominant (CP-d)

Revenues not sufficient for positive NPV (no-build)

2.8 Expiration of HPTC After 10 Years

At present, the IRA provides for 10 years of the HPTC. The expiration of the HPTC after 10 years is not modeled in the base case, rather, the base case assumes the tax credit applies for the full project lifetime of 30 years. This is also true for all cases outside of this section. While an extension of these credits is possible, the loss of HPTC revenue after 10 years should be considered. This section replicates the sensitivity study of Section 2.2, but with the HPTC applied only during the first 10 years of the project lifetime. Furthermore, due to the 10 year duration of tax credits, this case was also run with 15 year and 10 year project lifetimes. The study was also run with various price signals other than the default (2021 DAM), as the relatively low NPVs were found to be sensitive to the choice of price signal.

Note that as stated in Section 1.4, the electrolyzer always purchases power from the DAM. The price signals stated below apply to the fuel cell, with the electrolyzer using the corresponding year's DAM price signal. For example, when text below calls out the 2022 RTM, this indicates that the fuel cell sold power into the 2022 RTM while the electrolyzer purchased power from the 2022 DAM.

Results

Limiting the HPTC to the first 10 years of the project eliminates or significantly reduces profitability for the base case and other HPTC-dominant subcases. Selecting different price signals and re-running the sensitivity study was sufficient to shift subcases within that sensitivity study from unprofitability to low profitability.

With a 30 year project lifetime, the default 2021 DAM price signal, as well as the 2022 DAM and 2021 RTM, did not yield profitable HPTC-dominant solutions (Table 22 shows the 2021 DAM results). Only with the 2019 DAM price signal (Table 23) were marginally profitable HPTC-dominant solutions obtained (NPV of $80,000 at the default CP of $2.5/kW-month), and only at the full HPTC rate of $3/kg, with $2.5/kg no longer sufficient.

With 15 year project lifetime (Table 24–Table 26), the default 2021 DAM price signal, 2019 DAM, and 2021 RTM produced profitable solutions at the base case HPTC and CP rate along with other HPTC-dominant solutions, while the 2022 DAM and 2022 RTM did not. However, with the default price signal (2021 DAM) and at the default HPTC and CP rate, the NPV was only $190,000, and the highest HPTC-dominant NPV reached was $460,000. HPTC rates of $2.5/kg remained insufficient, except with the 2019 DAM, whereby very low NPVs were reached (<$300,000).

A 10 year project lifetime was run only with the default, 2021 DAM price signal (Table 27), due to time constraints. With this bare-minimum project lifetime, an NPV greater than $1 million was reached in several HPTC-dominated subcases, and the $2.5/kg HPTC level became profitable in HPTC-dominated cases. Subcases that exceeded $1 million NPV had an HPTC of $3/kg and added electrolyzer capacities, or no added electrolyzer capacity with an HPTC of $3/kg and $10/kW-month CP. With default HPTC and CP rates, the project became profitable with zero, +1, and +2 MW added electrolyzer capacities (NPVs of $0.74 million, $1.05 million, and $1.36 million, respectively). CP-dominated cases had lower NPV than with the 15 year lifetime, repeating the trend seen when reducing the full 30 year lifetime to a 15 year lifetime.

Regardless of project lifetime, most CP-dominant solutions continue to be profitable. High CP, low HPTC cases (e.g., top right of Table 22) are unchanged from the 30-year HPTC sensitivity study (Section 2.2) as they have little contribution from the HPTC, and high CP, high HPTC cases (bottom right) have lower NPV than under the default 30 year tax credit assumption. Lower NPV in high CP, high HPTC cases is due to the reduced contribution from the HPTC, while the system incurs the same capital and operating expenses for unchanged fuel cell and storage capacities. This produced drops in NPV of up to 43% compared to Section 2.2 for 2021 DAM with the 15 year life (Table 24). Subcases at $3/kg, $15/kW-month and $2.5/kg, $15/kW-month see a decrease in NPV over 60% while becoming neutral and lightly

CP dominant, respectively. Finally, when selling to the 2021 RTM, one subcase that is typically HPTC dominant under full-life tax credits arrived at a marginally profitable CP-dominant solution ($3/kg, $10/kW-month; $30,000 NPV).

At default CP and HPTC rates, profitable subcases with an NPV greater than $500,000 include the 10 year lifetime with or without added electrolyzer capacity (2021 DAM) and the 15 year lifetime with the 2019 DAM. These results are summarized by listing in Table 28 [i].

Key Takeaways

- In the event that the HPTC expires or is reduced after 10 years, ending system operation at Year 10 can preserve profitability, unless poor electricity market conditions (high prices for the electrolyzer power) were prevalent over those 10 years of operation.
  - Prolonging operation past Year 10 can only decrease NPV as every additional year will be at a loss.

Table 22. Results with 10 year limit on HPTC, 30 year lifetime, 2021 DAM price signal, with fuel cell capacity factors shown in parentheses.

		CP rate [$/kW-month]					
HPTC [$/kg]		2.51	5	10	15	20	30
0	NPV [$M]	0	0	0	0	3.66	12.45
	Tank [kg]	0	0	0	0	2534	2534
	FC [MW] (cap. fact.)	0	0	0	0	10.98 (0)	10.98 (0)
1	NPV [$M]	0	0	0	0	3.66	12.45
	Tank [kg]	0	0	0	0	2534	2534
	FC [MW] (cap. fact.)	0	0	0	0	10.98 (0)	10.98 (0)
2	NPV [$M]	0	0	0	0.22	4.50	13.12
	Tank [kg]	0	0	0	2681	2625	2514
	FC [MW] (cap. fact.)	0	0	0	10.70 (0.032)	10.74 (0.031)	10.80 (0.031)
3	NPV [$M]	0	0	0	1.32	5.60	14.22
	Tank [kg]	0	0	0	2699	2644	2514
	FC [MW] (cap. fact.)	0	0	0	10.69 (0.034)	10.72 (0.034)	10.80 (0.034)

Revenues not sufficient for positive NPV (no-build)   Capacity payment dominant (CP-d)

[i] Though not run in this study due to time constraints, presumably, the 2019 DAM price signal would lead to a more profitable result when paired with a 10 year lifetime than with a 15 year lifetime.

Table 23. Results with 10 year limit on HPTC, 30 year lifetime, 2019 DAM price signal, with fuel cell capacity factors shown in parentheses.

HPTC [$/kg]		CP rate [$/kW-month] 2.51	5	10	15	20	30
2.5	NPV [$M]	0	0	0	1.06	5.37	14.02
	Tank [kg]	0	0	0	2607	2533	2496
	FC [MW] (cap. fact.)	0	0	0	10.746 (0.034)	10.791 (0.034)	10.813 (0.034)
3	NPV [$M]	0.08	0.19	0.39	1.63	5.94	14.59
	Tank [kg]	84	84	84	2607	2533	2496
	FC [MW] (cap. fact.)	0.365 (0.989)	0.365 (0.989)	0.365 (0.989)	10.746 (0.034)	10.791 (0.034)	10.813 (0.034)

Hydrogen Production Tax Credit dominant (HPTC-d)
Capacity payment dominant (CP-d)
Revenues not sufficient for positive NPV (no-build)

Light HPTC-d (0.5 < CP:HPTC < 0.8)
Light CP-d (1.2 < CP:HPTC < 2)
Neutral (0.8 < CP:HPTC < 1.2)

Table 24. Results with 10 year limit on HPTC, 15 year lifetime, 2021 DAM price signal, with fuel cell capacity factors shown in parentheses.

HPTC [$/kg]		CP rate [$/kW-month] 2.51	5	10	15	20	30
2	NPV [$M]	0	0	0	0	2.69	9.64
	Tank [kg]	0	0	0	0	2625	2514
	FC [MW] (cap. fact.)	0	0	0	0	10.735 (0.033)	10.802 (0.033)
2.5	NPV [$M]	0	0	0	0.52	3.25	10.20
	Tank [kg]	0	0	0	913	2625	2514
	FC [MW] (cap. fact.)	0	0	0	3.165 (0.113)	10.735 (0.034)	10.802 (0.034)
3	NPV [$M]	0.19	0.27	0.44	1.08	3.82	10.77
	Tank [kg]	84	84	84	926	2625	2514
	FC [MW] (cap. fact.)	0.365 (0.982)	0.365 (0.982)	0.365 (0.982)	3.211 (0.113)	10.735 (0.034)	10.802 (0.034)

Table 25. Results with 10 year limit on HPTC, 15 year lifetime, 2019 DAM price signal, with fuel cell capacity factors shown in parentheses.

HPTC [$/kg]		CP rate [$/kW-month] 2.5	5	10	15	20	30
2	NPV [$M]	0	0	0	0.25	2.96	9.94
	Tank [kg]	0	0	0	767	2533	2496
	FC [MW]	0	0	0	2.776	10.791	10.813
	(cap. fact.)				(0.130)	(0.034)	(0.034)
2.5	NPV [$M]	0.05	0.13	0.30	0.82	3.52	10.50
	Tank [kg]	84	84	84	771	2533	2496
	FC [MW]	0.365	0.365	0.365	2.794	10.791	10.813
	(cap. fact.)	(0.990)	(0.990)	(0.990)	(0.130)	(0.034)	(0.034)
3	NPV [$M]	0.61	0.69	0.86	1.38	4.09	11.07
	Tank [kg]	84	84	84	773	2533	2496
	FC [MW]	0.365	0.365	0.365	2.8	10.791	10.813
	(cap. fact.)	(0.994)	(0.994)	(0.994)	(0.130)	(0.034)	(0.034)

Hydrogen Production Tax Credit dominant (HPTC-d)

Capacity payment dominant (CP-d)

Revenues not sufficient for positive NPV (no-build)

Light HPTC-d (0.5 < CP:HPTC < 0.8)

Light CP-d (1.2 < CP:HPTC < 2)

Neutral (0.8 < CP:HPTC < 1.2)

Table 26. Results with 10 year limit on HPTC, 15 year lifetime, 2022 DAM price signal, with fuel cell capacity factors shown in parentheses.

HPTC [$/kg]		CP rate [$/kW-month] 2.51	5	10	15	20	30
2	NPV [$M]	0	0	0	0	2.24	9.15
	Tank [kg]	0	0	0	0	2699	2644
	FC [MW] (cap. fact.)	0	0	0	0	10.691 (0.026)	10.724 (0.025)
2.5	NPV [$M]	0	0	0	0	2.70	9.60
	Tank [kg]	0	0	0	0	2736	2662
	FC [MW] (cap. fact.)	0	0	0	0	10.669 (0.029)	10.713 (0.029)
3	NPV [$M]	0	0	0	0.43	3.19	10.10
	Tank [kg]	0	0	0	1118	2773	2662
	FC [MW] (cap. fact.)	0	0	0	3.476 (0.091)	10.646 (0.031)	10.713 (0.031)

Hydrogen Production Tax Credit dominant (HPTC-d)

Capacity payment dominant (CP-d)

Revenues not sufficient for positive NPV (no-build)

Table 27. Results with 10 year limit on HPTC, 10 year lifetime, 2021 DAM price signal, with fuel cell capacity factors shown in parentheses.

HPTC [$/kg]		CP rate [$/kW-month] 2.5	5	10	15	20	30
2	NPV [$M]	0	0	0	0	1.82	7.44
	Tank [kg]	0	0	0	0	2625	2514
	FC [MW] (cap. fact.)	0	0	0	0	10.735 (0.034)	10.802 (0.034)
2.5	NPV [$M]	0.18	0.25	0.38	0.53	2.38	8.00
	Tank [kg]	84	84	84	316	2625	2514
	FC [MW] (cap. fact.)	0.365 (0.985)	0.365 (0.985)	0.365 (0.985)	0.913 (0.393)	10.735 (0.034)	10.802 (0.034)
3	NPV [$M]	0.74	0.81	0.95	1.09	2.95	8.57
	Tank [kg]	84	84	84	330	2625	2514
	FC [MW] (cap. fact.)	0.365 (0.993)	0.365 (0.993)	0.365 (0.993)	0.974 (0.372)	10.735 (0.034)	10.802 (0.034)

Table 28. Effect of changing project lifetime and price signal on NPV.

10 year life, 2021 DAM, +2 MW electrolyzer	$1.36M
10 year life, 2021 DAM, +1 MW electrolyzer	$1.05M
10 year life, 2021 DAM, no added capacity	$0.74M
15 year life, 2019 DAM, no added capacity	$0.61M

3. DISCUSSION

Coupling an electrolyzer, a storage tank, and a fuel cell to create an integrated energy system that coproduces hydrogen and electricity is profitable. Surprisingly, for the nominal base case, we found the fuel cell is sized precisely to consume the maximum possible rate of H_2 produced by the electrolyzer and does not act as a peaking unit, but instead produces electricity nearly continuously. This continuous generation is interrupted by only several shutdowns per year, each from one to a few hours in length, as seen by the near-unity capacity factor. The electrolyzer acts in parallel, shutting down at the same times and at all other times continuously producing hydrogen, which is passed to the storage tank to replenish the same quantity of hydrogen used by the fuel cell. The storage tank, smaller than a single tube trailer, only holds enough hydrogen to satisfy the capacity market requirements, and so its stored mass of 84 kg remains constant. This behavior may change if the constraint is relaxed to enforce the minimum level daily, rather than hourly.

When varying HPTC from zero to $3/kg and CP rate from a typical present-day $2.5/kW-month to over ten times higher, it was found that drastic changes to the magnitude of the design variables (storage tank and fuel cell capacity) and operational behavior (fuel cell capacity factor) occur when CP rates are multiple times that of present-day rates, namely, $15/kW-month and above. At high CP rates, a large fuel cell (10–11 MW) results and rarely operates, along with a large storage tank (2500–2600 kg, equivalent to several tube trailers). The two distinct behaviors were classified as either HPTC or CP dominant by revenue. In each type, the namesake revenue was double or more of the other revenue.

An HPTC-dominant solution features smaller fuel cells, with capacities <1 MW (<2 MW in cases where electrolyzer capacity has been added). Likewise, storage tank capacity and total capital expenditures are relatively low. Conversely, capacity factors for the electrolyzer and fuel cell are relatively high: near one in most cases. At CP = $2.5, $5/kW-month, the electrolyzer and fuel cell remain in lockstep with identical capacity factors of 0.98–0.99. At an intermediate CP rate ($10/kW-month), the HPTC still dominates, while the storage tank approaches the size of a tube trailer and the fuel cell is sized about double of its base case capacity and operates flexibly as indicated by capacity factors of ~0.58, presumably in response to the changing price signal.

A CP-dominant solution is characterized by drastically larger fuel cells than when the HPTC dominates (fuel cell capacities 29–30× larger). The change in fuel cell capacity is sudden with respect to the CP rate variable, with the larger fuel cell capacities appearing over a single step increase in the CP (a difference of $5) and generally persisting with a nearly stable value for all higher CP levels. A higher storage tank capacity is coupled with the increase in fuel cell capacity, and the total capital expenses reach the upper limit ($12.5 million). CP-dominant solutions have NPVs generally multiple times higher than the HPTC-dominant solutions at the same HPTC rate, but the lowest NPV CP-dominant solutions (CP = $15/kW-month, the lowest possible for CP dominant, with intermediate HPTC of $1.5/kg and $2/kg) have NPV similar to the lowest NPV HPTC-dominant solutions, while investing the maximum capital investment of $12.5 million compared to the sub-$1 million capital investments for HPTC-dominant solutions. Capacity factors for the electrolyzer and fuel cell are extremely low, with fuel cell capacity factors as high as 0.125 and as low as zero.

Because pre-existing electrolyzer capacity was used and thus fixed in all other cases, adding electrolyzer capacity was also considered. Under default assumptions (HPTC of \$3/kg and CP of \$2.5/kW-month), adding 1 and 2 MW of electrolyzer capacity was found to increase the NPV (and presumably any amount would do so). A positive effect on the NPV remained for a reduced HPTC as low as \$2/kg and for CP rates up to \$10/kW-month. At the next-higher CP level (\$15), due to the shift to CP-dominated solutions, an additional electrolyzer did not benefit the NPV regardless of HPTC rates.

Prescribing a fixed fuel cell capacity is not optimal. The larger optimal capacity reached when adding electrolyzer capacity (e.g., 1 MW for 2 MW of additional electrolyzer capacity, bringing the electrolyzer to ~3 MW) leads to a higher NPV, as previously stated.

Altering the fuel cell capital cost rate from the default assumption of \$1,000/kW has a modest impact. A decreased cost rate brings subcases at low HPTC rates and intermediate CP rates (\$10–\$15/kW-month) to profitability, and a decrease by 50% allows all subcases at CP rate of \$10/kW-month to be profitable, even with no HPTC. Conversely, an increase of 25% makes profitability under the previously HPTC-independent \$15/kW-month CP level depend on a \$3/kg HPTC.

In the event that the HPTC is not extended past the current length of 10 years, results indicate that ending the project life at 10 years allows the project to remain profitable with a \$0.74 million NPV for the base case with a 10 year project lifetime. Changes in electricity prices may impact the profitability as electricity is the primary operating cost.

A hypothetical scenario of claiming two types of tax credits was considered. If the fuel cell is eligible to earn a tax credit, equal in value to the zero-emission nuclear power production credit (\$15/MWh), and this latter credit must be forgone on electricity generated by the NPP but used by the electrolyzer, the effect of such an arrangement is to dramatically decrease NPV.

The effect of price signals other than the default used was also considered. Generally, a higher mean price (LMP) leads to a lower NPV. Logically, this is because electricity is the major component of operating costs, while only a fraction of the electric energy used to generate hydrogen can be converted back to electricity for sale.

Importantly, the economics of the system will shift dramatically if full capital costs are considered. When groundwork, engineering, labor, and installation are considered, based on the industry partner's estimated range for a generic site (\$5 million–\$10 million), very high CP rates become necessary. Taking the lower bound of the estimate, a CP rate of \$20/kW-month with an HPTC rate of \$2/kg is the minimum combination needed for profitability; for the upper bound, only \$30/kW-month is sufficient with or without HPTC. If the capital cost of the default electrolyzer is included (~\$1 million), the minimum HPTC rate rises to \$2.5/kg at \$20/kW-month in the case of the lower bound for the listed costs (\$5 million).

An awaited decision by the U.S. Treasury Department on the exact action that earns the HPTC—production of hydrogen versus its use—does not impact the project economics or operational behavior at the default HPTC rate of \$3/kg and default CP rate of \$2.5/kW-month.

Finally, it is clear that HPTC rates at an effective \$3/kg incentivize hydrogen production in the manner described here, while typical present-day CP rates in the NYISO capacity market if not paired with the HPTC are insufficient to spur the construction of hydrogen-based systems of the kind described in this report. With HPTC, incentives may still be insufficient, as an NPV of \$1.36 million may not be attractive and may wholly disappear when capital expenditures in site preparation, etc., are considered. The NPV is sensitive to total capital expenditures, and accurate estimation of capital expenditures is critical.

If dramatically higher CP rates of \$15 kW-month and above become common in the future (\$20/kW-month without any level of HPTC), a system with a 10× ratio between electrolyzer and fuel cell by electric power becomes the optimal solution, acting as a system in reserve and rarely generating electricity. At CP rates of \$30/kW-month, NPVs would be high enough to profitably absorb the \$5 million–\$10 million capital expenditures for groundwork, engineering, labor, and installation not considered in the main body of this report.

4. CONCLUSIONS AND FUTURE WORK

This case study showed that, under nominal present-day HPTC and CP rates, an integrated energy system that draws electrical energy from a baseload NPP and stores it as hydrogen for later electric generation is mildly profitable (NPV of \$1.4 million) when capital expenditures specific to the industry partner's site were considered (only the cost of system components included) and when tax credits continue throughout a 30-year plant lifetime. To reach multimillion-dollar NPVs, CP rates would have to be several times higher than present-day (approximately \$15/kW-month vs. \$2.5/kW-month). The HPTC improves the system economics, and a build decision may be marginally profitable even in the eventuality that the HPTC is not renewed after 10 years; however, the system would cease operation after Year 10, and present-day CP rates would be insufficient for continued operation. In either case, adding electrolyzer capacity beyond the existing 1.06 MW increases profitability, as long as the HPTC is \$2/kg or above while the system operates. However, because the NPV is sensitive to total capital expenditures, making accurate estimation of capital expenditures becomes critical if evaluating viability of a similar system at a generic site.

This case study was enabled by the DISPATCHES modeling framework which facilitates the co-optimization of IES design and operating decisions considering time-varying electricity prices. The highly flexible nature of the DISPATCHES framework supports several possible extensions to this analysis as future work, including analysis of similar and dissimilar systems with and without economic incentives.

Potential future work includes redefining the 4 hour minimum storage constraint as a daily constraint, rather than a constraint that applies at all times. This would allow the optimizer to use some or all of the hydrogen stored in the storage tank at times while still fully earning CP revenue, likely changing the solution in the base case (which currently results in a minimal, constantly full storage tank). A second possibility for future work is analyzing a system with a reversible electrolyzer and fuel cell substituted for the standalone electrolyzer and standalone fuel cell. Perhaps naturally, including hydrogen sales would be a worthwhile extension of this work.

5. REFERENCES

1. Richardson, Ian A., et al. "Low-cost, transportable hydrogen fueling station for early market adoption of fuel cell electric vehicles." international journal of hydrogen energy 40.25 (2015): 8122-8127. https://doi.org/10.1016/j.ijhydene.2015.04.066

2. N. Rustagi, A. Elgowainy, and J. Vickers. (2018). "Current Status of Hydrogen Delivery and Dispensing Costs and Pathways to Future Cost Reductions." Record #18003, DOE Hydrogen and Fuel Cells Program. https://www.hydrogen.energy.gov/pdfs/18003_current_status_hydrogen_delivery_dispensing_costs.pdf.

3. A. Wilson, G. Kleen, and D. Apageorgopoulos. (2017) "Fuel Cell System Cost – 2017." Record #17007, DOE Hydrogen and Fuel Cells Program Record. https://www.hydrogen.energy.gov/pdfs/17007_fuel_cell_system_cost_2017.pdf

4. PNNL. (n.d.). Hydrogen Analysis Resource Center. Pacific Northwest National Laboratory, *H_2 Hydrogen Tools*. https://h2tools.org/hyarc/calculator-tools/lower-and-higher-heating-values-fuels.

Appendix A
Results with Added Capital Expenditures

Including groundwork, engineering, labor, and installation, the estimated range for additional capital expenses is \$5 million–\$10 million in addition to those already included in the main body of this report. The results in this appendix were generated by subtracting these additional expenses from NPV and showing negative-NPV cases as zero NPV and no-build (design variables of zero). Two tables are presented: one for the lower bound of \$5 million (Table A-1), and one for the upper bound of \$10 million (Table A-2). For additional capital expenditures of \$5 million, a CP rate of \$20/kW-month is needed with an HPTC of at least \$2/kg. For additional capital expenditures of \$10 million, a CP rate of \$30/kW-month is needed, but the HPTC is no longer necessary because the high CP rate is sufficient.

Table A-1. Summary of results for identifying driving revenue with \$5 million of added capital expenditures accounted for, with fuel cell capacity factors shown in parentheses.

HPTC [\$/kg]		CP rate [\$/kW-month] 2.51	5	10	15	20	30
0	NPV [\$M]	0	0	0	0	0	7.45
	Tank [kg]	0	0	0	0	0	2534
	FC [MW] (cap. fact.)	0	0	0	0	0	10.98 (0)
0.5	NPV [\$M]	0	0	0	0	0	7.45
	Tank [kg]	0	0	0	0	0	2534
	FC [MW] (cap. fact.)	0	0	0	0	0	10.98 (0)
1	NPV [\$M]	0	0	0	0	0	7.67
	Tank [kg]	0	0	0	0	0	2514
	FC [MW] (cap. fact.)	0	0	0	0	0	10.8 (0.026)
1.5	NPV [\$M]	0	0	0	0	0	8.44
	Tank [kg]	0	0	0	0	0	2514
	FC [MW] (cap. fact.)	0	0	0	0	0	10.8 (0.033)
2	NPV [\$M]	0	0	0	0	0.68	9.30
	Tank [kg]	0	0	0	0	2644	2514
	FC [MW] (cap. fact.)	0	0	0	0	10.72 (0.034)	10.8 (0.034)
2.5	NPV [\$M]	0	0	0	0	1.55	10.16
	Tank [kg]	0	0	0	0	2644	2514
	FC [MW] (cap. fact.)	0	0	0	0	10.72 (0.034)	10.8 (0.034)
3	NPV [\$M]	0	0	0	0	2.42	11.03
	Tank [kg]	0	0	0	0	2644	2514
	FC [MW] (cap. fact.)	0	0	0	0	10.72 (0.034)	10.8 (0.034)

Capacity payment dominant (CP-d)

Revenues not sufficient for positive NPV (no-build)

Table A-2. Summary of results for identifying driving revenue with $10 million of added capital expenditures accounted for, with fuel cell capacity factors shown in parentheses.

		CP rate [$/kW-month]					
HPTC [$/kg]		2.51	5	10	15	20	30
0	NPV [$M]	0	0	0	0	0	2.45
	Tank [kg]	0	0	0	0	0	2534
	FC [MW] (cap. fact.)	0	0	0	0	0	10.98 (0)
0.5	NPV [$M]	0	0	0	0	0	2.45
	Tank [kg]	0	0	0	0	0	2534
	FC [MW] (cap. fact.)	0	0	0	0	0	10.98 (0)
1	NPV [$M]	0	0	0	0	0	2.67
	Tank [kg]	0	0	0	0	0	2514
	FC [MW] (cap. fact.)	0	0	0	0	0	10.8 (0.026)
1.5	NPV [$M]	0	0	0	0	0	3.44
	Tank [kg]	0	0	0	0	0	2514
	FC [MW] (cap. fact.)	0	0	0	0	0	10.8 (0.033)
2	NPV [$M]	0	0	0	0	0	4.30
	Tank [kg]	0	0	0	0	0	2514
	FC [MW] (cap. fact.)	0	0	0	0	0	10.8 (0.034)
2.5	NPV [$M]	0	0	0	0	0	5.16
	Tank [kg]	0	0	0	0	0	2514
	FC [MW] (cap. fact.)	0	0	0	0	0	10.8 (0.034)
3	NPV [$M]	0	0	0	0	0	6.03
	Tank [kg]	0	0	0	0	0	2514
	FC [MW] (cap. fact.)	0	0	0	0	0	10.8 (0.034)

Capacity payment dominant (CP-d)

Revenues not sufficient for positive NPV (no-build)

Page intentionally left blank

Appendix B
Results Under Nondefault Price Signals
B-1.

<u>Results corresponding to Section 2.2: What Drives Revenue?</u>

The default electricity price (LMP) signal used in Section 2 for all cases, is the 2021 DAM price (except where noted in Section 2.8). Below, when an RTM signal is used, it is only used for the revenue earned by selling electric power from the fuel cell, and the DAM for the same year is used for the cost of electric power consumed by the electrolyzer (as in Section 2.8).

For the base case, a switch to the 2021 RTM from the default price signal (2021 DAM) caused no changes. For other HPTC-dominant subcases at higher CP rates ($5 and $10/kW-month), the same switch led to larger tank sizes and fuel cell capacities, with no increase and a mild increase in NPV (6%), respectively. CP-dominant subcases showed little change. On the contrary, substituting the 2022 DAM price signal for the default price signal reduced the profitability of the base case by 85% and less but still significantly for other HPTC-dominant subcases, while mildly affecting CP-dominant subcases.

2021 RTM

Results when selling in the 2021 RTM, while still purchasing electricity in the 2021 DAM, are shown in Table B-1. For HPTC-dominant subcases, the primary effect of the switch to sell in the RTM in 2021 is an increase in tank sizes (up to 104%) and fuel cell capacities (up to 122%). NPVs change little (less than 6%).

CP-dominant subcases change insignificantly, except for NPVs of the $15/kW-month set, which is at the boundary of the two regions (increases of 11%–24%). Higher CP rates continue to increase the NPV.

Table B-1. Summary of results for identifying driving revenue, under 2021 RTM price signal.

		CP rate [$/kW-month]					
HPTC [$/kg]		2.51	5	10	15	20	30
0	NPV [$M]	0	0	0	0	3.66	12.45
	Tank [kg]	0	0	0	0	2534	2534
	FC [MW]	0	0	0	0	10.980	10.980
0.5	NPV [$M]	0	0	0	0	3.67	12.45
	Tank [kg]	0	0	0	0	2736	2534
	FC [MW]	0	0	0	0	10.669	10.980
1	NPV [$M]	0	0	0	0.07	4.29	12.82
	Tank [kg]	0	0	0	3009	2866	2681
	FC [MW]	0	0	0	10.505	10.591	10.702
1.5	NPV [$M]	0	0	0	0.87	5.09	13.60
	Tank [kg]	0	0	0	3009	2884	2718
	FC [MW]	0	0	0	10.505	10.580	10.680
2	NPV [$M]	0	0	0.10	1.73	5.95	14.46
	Tank [kg]	0	0	485	3009	2884	2718
	FC [MW]	0	0	1.279	10.505	10.580	10.680
2.5	NPV [$M]	0.51	0.61	0.94	2.59	6.81	15.32
	Tank [kg]	107	119	499	3009	2884	2718
	FC [MW]	0.371	0.391	1.340	10.505	10.580	10.680
3	NPV [$M]	1.36	1.47	1.79	3.46	7.68	16.19
	Tank [kg]	84	111	510	3009	2884	2718
	FC [MW]	0.365	0.388	1.388	10.505	10.580	10.680

Hydrogen Production Tax Credit dominant (HPTC-d)

Capacity payment dominant (CP-d)

Revenues not sufficient for positive NPV (no-build)

2022 DAM

Under the 2022 DAM prices (Table B-2), cases with a reduced HPTC rate of $2.5/kg are no longer viable. Among HPTC-dominant subcases, NPVs decrease by 85% for the base case, and less for others, with the smallest decrease of 63% at the boundary of the HPTC-dominant region ($3/kg–$10/kW-month). Storage tank size increased by 150% in the base case and up to 171%. Changes to the fuel cell capacity are insignificant, except for a 65% increase for the $3/kg–$10/kW-month subcase.

CP-dominant subcases see few significant changes, with those changes limited to the NPVs of the $15/kW-month set, which is at the boundary of the two regions (decreases of 25%–47%; for others, NPVs decreased 12% or less).

Table B-2. Summary of results for identifying driving revenue, under 2022 DAM price signal.

HPTC [$/kg]		CP rate [$/kW-month] 2.51	5	10	15	20	30
0	NPV [$M]	0	0	0	0	3.66	12.45
	Tank [kg]	0	0	0	0	2534	2534
	FC [MW]	0	0	0	0	10.980	10.980
0.5	NPV [$M]	0	0	0	0	3.66	12.45
	Tank [kg]	0	0	0	0	2534	2534
	FC [MW]	0	0	0	0	10.980	10.980
1	NPV [$M]	0	0	0	0	3.75	12.45
	Tank [kg]	0	0	0	0	2644	2534
	FC [MW]	0	0	0	0	10.724	10.980
1.5	NPV [$M]	0	0	0	0.04	4.31	12.88
	Tank [kg]	0	0	0	2792	2699	2625
	FC [MW]	0	0	0	10.635	10.691	10.735
2	NPV [$M]	0	0	0	0.74	5.00	13.56
	Tank [kg]	0	0	0	2847	2736	2662
	FC [MW]	0	0	0	10.602	10.669	10.713
2.5	NPV [$M]	0	0	0	1.52	5.77	14.32
	Tank [kg]	0	0	0	2866	2792	2662
	FC [MW]	0	0	0	10.591	10.635	10.713
3	NPV [$M]	0.21	0.32	0.63	2.34	6.58	15.13
	Tank [kg]	211	228	492	2866	2792	2662
	FC [MW]	0.365	0.396	1.035	10.591	10.635	10.713

Hydrogen Production Tax Credit dominant (HPTC-d)

Capacity payment dominant (CP-d)

Revenues not sufficient for positive NPV (no-build)

B-2.

<u>Results corresponding to Section 2.4: Exploring Prescribed Fuel Cell Capacity on the Order of Megawatts Together with Additional Electrolyzer Capacity</u>

Selling electricity in the 2021 RTM rather than in the 2021 DAM leads to modest increases in NPVs through a mild increase in the share of revenue from electricity sales. This greater revenue is most helpful when the fuel cell is large (e.g., +2 MW and +5 MW) as prescribed by the case. Nevertheless, the subcases with prescribed fuel cell capacity still have lower NPVs than those with an optimized fuel cell size.

2021 RTM

Impacts of selling in the 2021 RTM compared to selling in the 2021 DAM are modestly positive. For all subcases in which the NPV changed by at least 1%, NPVs went up. This manifests itself significantly in the +1 MW electrolyzer, 5 MW fuel cell subcase (151%; however, NPV remains below $1 million), in the +1 MW, 2 MW subcase (15%), and to a lesser degree in the +2MW, 2 MW subcase (7%). The +1 MW, 2 MW subcase changes from a negative to positive NPV, rounding out the benefits for the 2 MW fuel cell capacity column. The remaining subcases at 5 MW fuel cell capacity see NPVs become less negative.

In all the subcases mentioned above, the revenue from selling electricity increased by 1–3 percentage points, while HPTC revenue went down (even as all subcases remain HPTC dominant). The accompanying increase in electricity costs was not so large as to completely offset the increased electricity revenues. Fuel cell capacity factors were virtually unchanged (≤0.002 difference). At a minimum, the effect of the RTM price signal is to allow the system to earn greater revenue from selling electricity when the fuel cell is large. Regardless, the optimal fuel cell capacity still produces higher NPVs than prescribed fuel cell capacity.

B-3.

<u>Results corresponding to Section 2.5: Effect of Fuel Cell Capital Cost</u>

When the sensitivity study is conducted while selling in the RTM (2021 RTM price signal), the otherwise base case (HPTC = \$3/kg, CP = \$2.5/kW-month) is unchanged in the three key metrics presented in the tables. However, for other HPTC-dominant subcases, storage tank and fuel cell size increase as fuel cell cost is reduced.

2021 RTM

HPTC-dominant subcases see next to no change in NPVs (≤1%); however, optimal design variables both increase. The increase is more pronounced at a higher CP rate, with increases to the storage tank of 30%–78% (\$2.5/kW-month) and 67%–111% (\$3/kW-month) and to the fuel cell of 5%–22% (\$2.5/kW-month) and 17–92% (\$3/kW-month). Additionally, for the increased capital cost level of +25%, the HPTC-dominant case at CP of \$10/kW-month sees an increase of 120% in the storage tank and 40% in the fuel cell. Lightly HPTC-dominant cases, on the other hand, increased in NPVs slightly, with one subcase increasing in NPVs by 15% and decreasing in fuel cell capacity by 11%.

For capacity-dominant subcases, the RTM has the greatest effect on the subcase NPV with the lowest CP and HPTC (\$1/kg), followed by the subcase with the lowest CP and the next-lowest HPTC (\$2/kg) (the lowest CP is \$10, \$15, \$15, and \$20/kW-month for capital cost levels of -50%, -30%, -15%, and +25%, respectively). For these subcases, NPVs increased by 19%–24% for \$1/kg and 10%–12% for \$2/kg, except for the -30% level, for which the effect was more muted at 5% and 6%. Storage tank size and fuel cell capacity were not significantly affected (in one instance at the +25% level, the storage tank increased by 12%). Additionally, lightly CP-dominant cases became neutral and increased in NPVs by a large amount, with neither revenue being more than 1.2× larger than the other; however, none of these cases reached \$1 million in NPV.