Valuation of Hydrogen Technology on the Electric Grid Using Production Cost Modeling

Cooperative Research and Development Final Report

CRADA Number: CRD-18-00736

NREL Technical Contact: Joshua Eichman

NREL is a national laboratory of the U.S. Department of Energy
Office of Energy Efficiency & Renewable Energy
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Contract No. DE-AC36-08GO28308

Technical Report
NREL/TP-5400-82932
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Cooperative Research and Development Final Report

Report Date: September 16, 2020

In accordance with requirements set forth in the terms of the CRADA agreement, this document is the final CRADA report, including a list of subject inventions, to be forwarded to the DOE Office of Scientific and Technical Information as part of the commitment to the public to demonstrate results of federally funded research.

Parties to the Agreement: Electric Power Research Institute (EPRI)

CRADA Number: CRD-18-00736

CRADA Title: Valuation of Hydrogen Technology on the Electric Grid Using Production Cost Modeling

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Sponsoring DOE Program Office(s):

Office of Energy Efficiency and Renewable Energy (EERE), Hydrogen and Fuel Cell Technologies Office (HFTO)

Joint Work Statement Funding Table showing DOE commitment:

Estimated Costs	NREL Shared Resources a/k/a Government In-Kind
Year 1 Year 2, Modification #2	$96,000.00 $16,000.00
TOTALS	$115,000.00

Executive Summary of CRADA Work:

This research project will estimate the value to the United States electric grid of deploying hydrogen technology (such as electrolyzers and hydrogen-fueled generation) under projected conditions of high renewable penetration. The analysis will advance the state of the art in systems-level cost-benefit analysis of hydrogen technology for the electric grid by incorporating production cost modeling results in the analysis. Large-scale grid simulation tools will be used to evaluate total system production cost and grid operation when hydrogen technology is deployed for applications such as energy storage and demand response. Scenarios will include one or more future grid mixes in the Western Interconnect (WI) with a high proportion of intermittent renewables. Electric Power Research Institute (EPRI) will work with four utility companies to refine scenarios. Results of the analysis will include comparing the net cost of hydrogen to other technologies for long duration storage, and of power-to-gas (P2G) scenarios including merchant hydrogen sale and hydrogen-fueled generation.

Summary of Research Results:

Recent advances in a variety of hydrogen technologies, and the changing requirements of the electric grid, are dramatically expanding the potential technical and economic opportunities for hydrogen generation and consumption to interface with the electric grid. Several types of interaction between hydrogen technology and the electric grid are possible. Key interactions include the use of grid electricity to produce hydrogen (particularly during periods of overgeneration); the use of fast-response electrolyzers to provide grid balancing services; and energy storage over long periods using hydrogen. This work develops and applies a novel systems modeling approach, pairing capacity expansion results with production cost modeling simulation, to assess the system-level economic impacts of hydrogen-grid integration for future high-renewables scenarios in the U.S. Western Interconnection. This analysis further incorporates projected capital costs of alternative energy storage technologies, and projected revenues from merchant sale of hydrogen, for integrated comparative cost-benefit analysis across a range of bulk storage and hydrogen technology deployment scenarios, for several years out to 2050. To probe these effects, a wide range simulation scenarios probed the impacts of adding 2,000 MW of energy storage capacity or flexible electrolyzer capacity to region p10 (southern California). Energy storage technologies evaluated include redox flow batteries (RFB), compressed air energy storage (CAES), pumped hydro storage (PHS), electrolytic hydrogen production followed by fuel cell power generation (H2-FC), and electrolytic hydrogen production followed by combustion turbine power generation (H2-CT).

The production cost model begins to dispatch storage in a seasonal manner at renewable penetration levels between 49% (2024) and 65% (2032) in the Western Interconnect. Simulations identified system-wide value (i.e. avoided production costs) resulting from operation of energy storage, which increased with increasing share of renewable generation and with the round-trip efficiency of the energy storage resource. However, this value ($10–50/kW-yr) was significantly smaller than the estimated value of capacity available to the energy storage resource (estimated here at $200/kW-yr). A wide range of energy storage duration was evaluated, ranging from 1 day to 1 month. Cost-benefit analysis indicates that given current market structures energy storage systems with one day of storage discharge duration are more cost effective (i.e. benefit/cost ratio greater than or equal to one) than systems with longer durations, though some longer duration storage systems are also cost effective. For less than one week of duration, CAES is the most cost effective of the technologies considered and for durations of one week or more hydrogen is the most cost-effective technology on account of its lower energy capital cost.

1. Implement storage devices into PLEXOS WECC database

Long duration storage and demand response technologies including hydrogen were successfully modeled in the production cost modeling framework. Due to the complexities of seasonal planning, developing an optimal framework was challenging. We first identify promising modeling strategies and implemented several to find a reliable and high quality method for optimally dispatching storage and demand response devices.

2. Implement high renewable scenarios into the PLEXOS WECC database

The team successfully developed a high renewable production cost modeling database for the Western Interconnect. To do this we leveraged the ReEDS capacity expansion tool and their standard scenarios. We used the “National 80% RPS” scenario as a basis for the PLEXOS databases (see Figure 1).

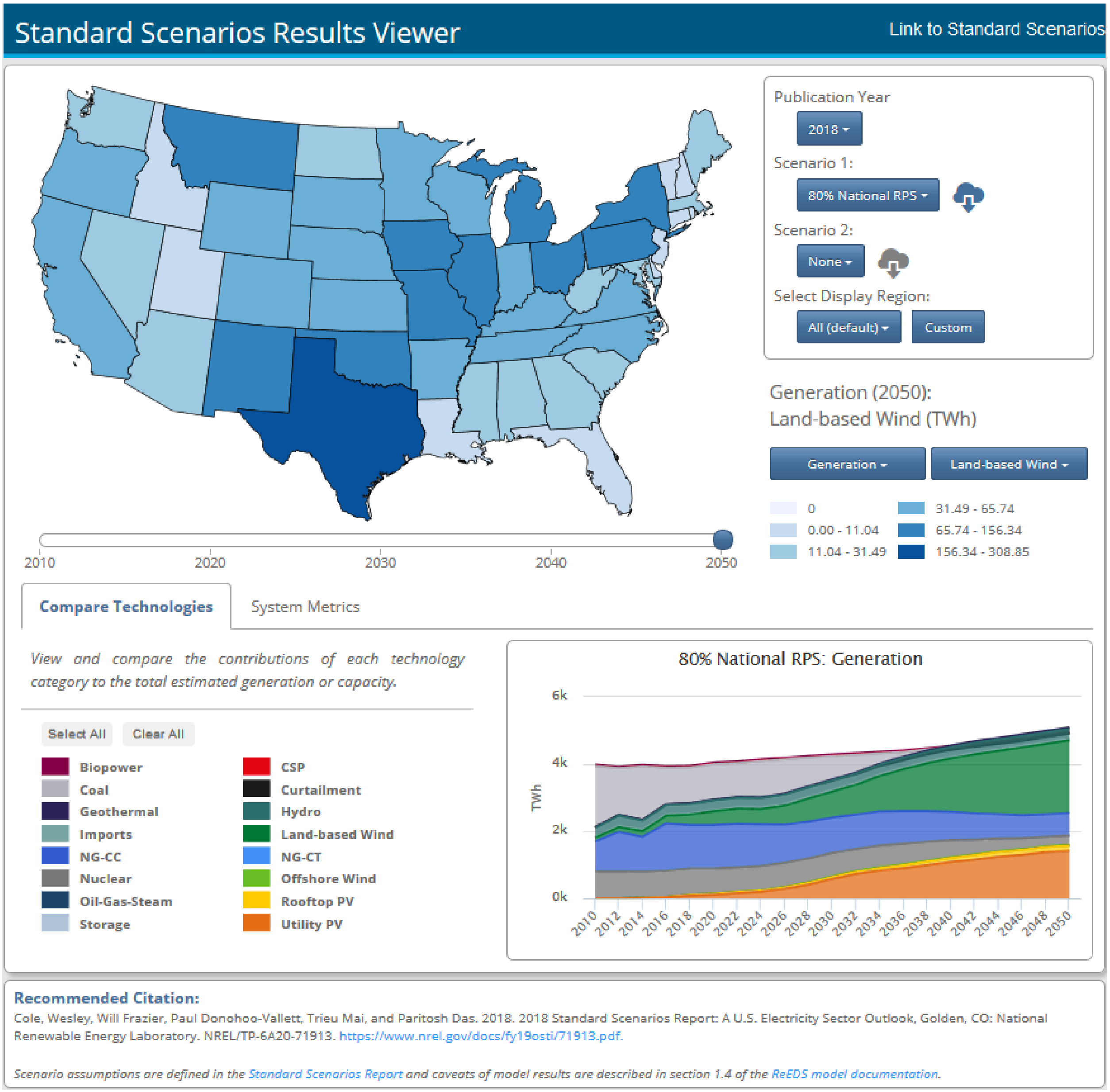

Figure 1: Example ReEDS summary output for the 80% National RPS scenario (https://openei.org/apps/reeds/#)

The ReEDS output databases were converted to PLEXOS using the newly developed ReEDS-to-PLEXOS tool at NREL. This allows us to seamlessly perform capacity expansion to achieve desired system properties and then translate that to PLEXOS to run detailed unit commitment and economic dispatch.

Several databases were created to understand the transition to high renewable systems (see Table 1). For just the Western Interconnect, the renewable penetration ranged from 49% to 85%, including large hydro.

Table 1: ReEDS projections for percent generation from renewables, total generation capacities, and annual load, for various years analyzed.

Target Year	Renewable Penetration (including large hydro)	Total Capacity (GW)	Total Load (TWh)
2024	49%	231	801
2032	65%	300	858
2036	74%	332	897
2040	81%	377	956
2050	85%	454	1124

The ReEDS capacity expansion model considers several energy storage technologies when determining cost-optimal grid topologies to meet future system demand. These include lithium ion batteries (with 4 hours of duration); CAES (with 12 hours of duration); and PHS (with 12 hours of duration). Figure 5 shows the installed storage capacity in the capacity expansion results for the target analysis years. It can be seen that the projected storage capacity increases rapidly from 2024 to 2050, as the share of renewable generation increases, and lithium ion battery costs are projected to decrease. The majority of new additions come from CAES and lithium ion batteries. Overall, there is a significant amount of existing storage in the WI. The following figures examine the basecase PLEXOS solution results without any additional storage or demand response.

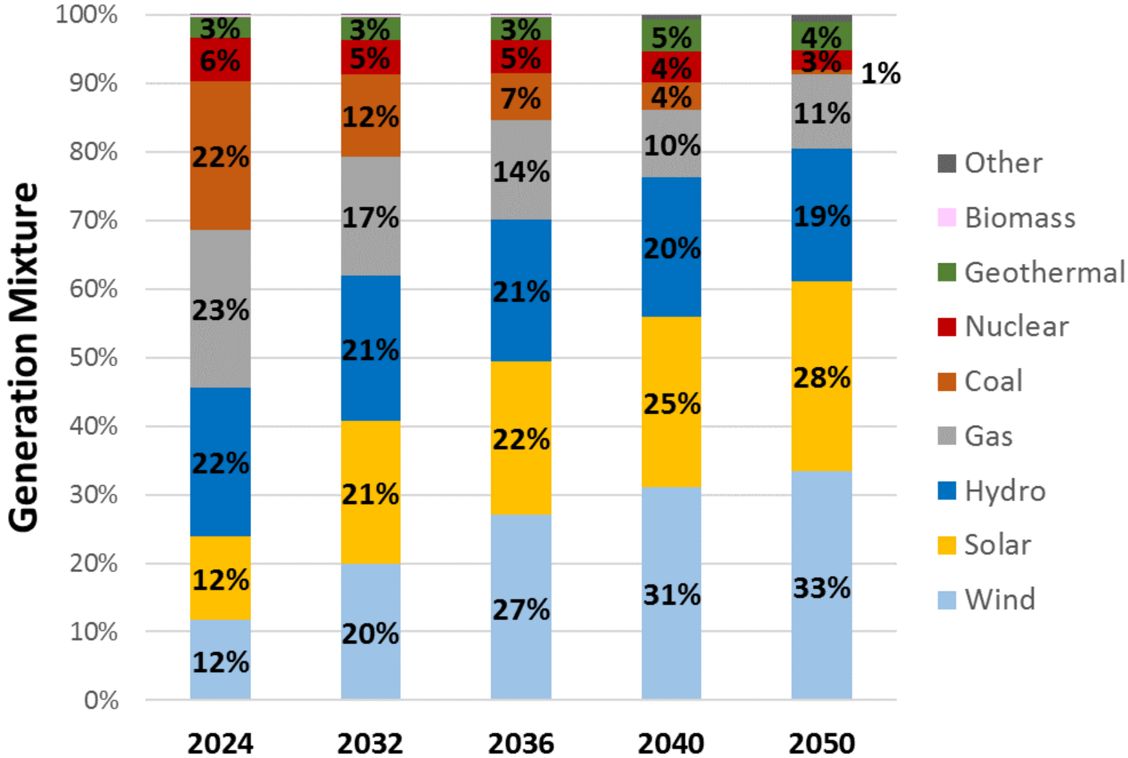

Figure 2: Generation mixes determined by ReEDS for various future years.

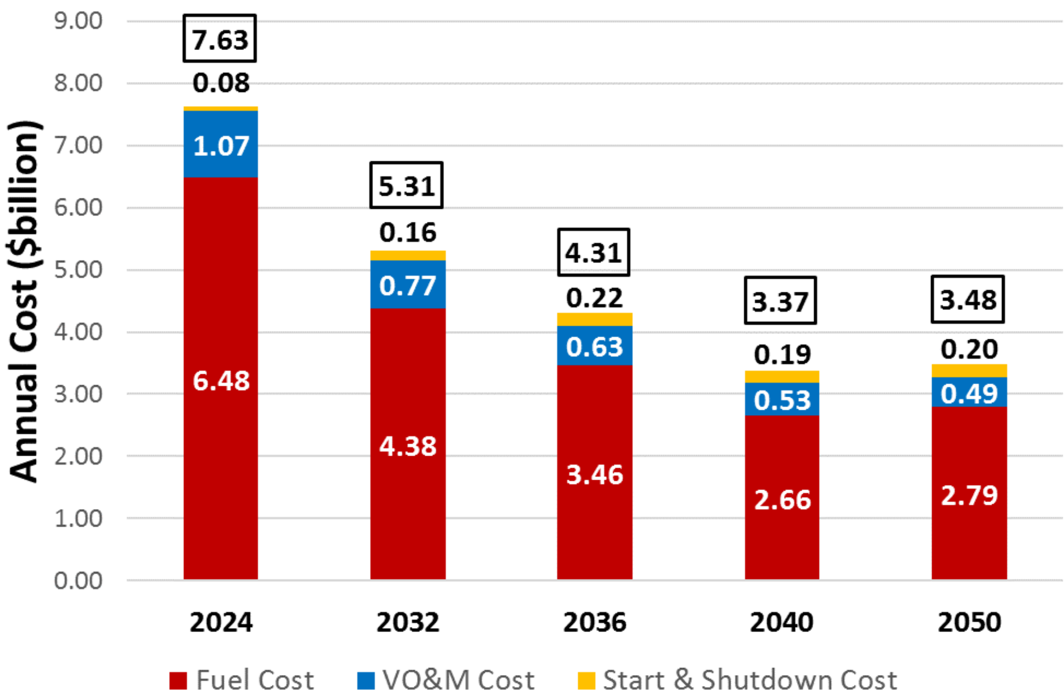

Figure 3: Production cost for Western Interconnect (based on PLEXOS) with grid configuration generated from ReEDS capacity expansion result based on National 80% RPS scenario.

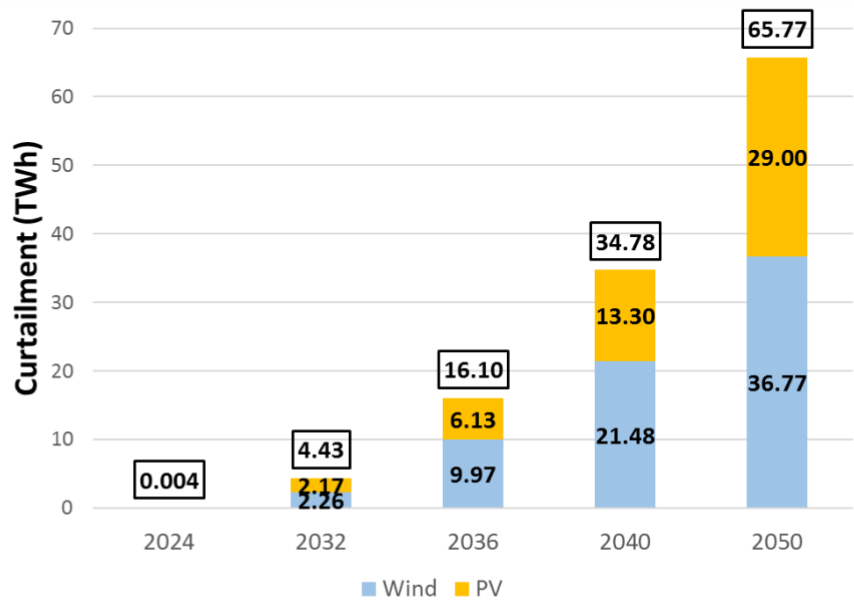

Figure 4: Total curtailment of wind and solar in Western Interconnect, projected by PLEXOS, with grid configuration generated from ReEDS capacity expansion result based on National 80% RPS scenario.

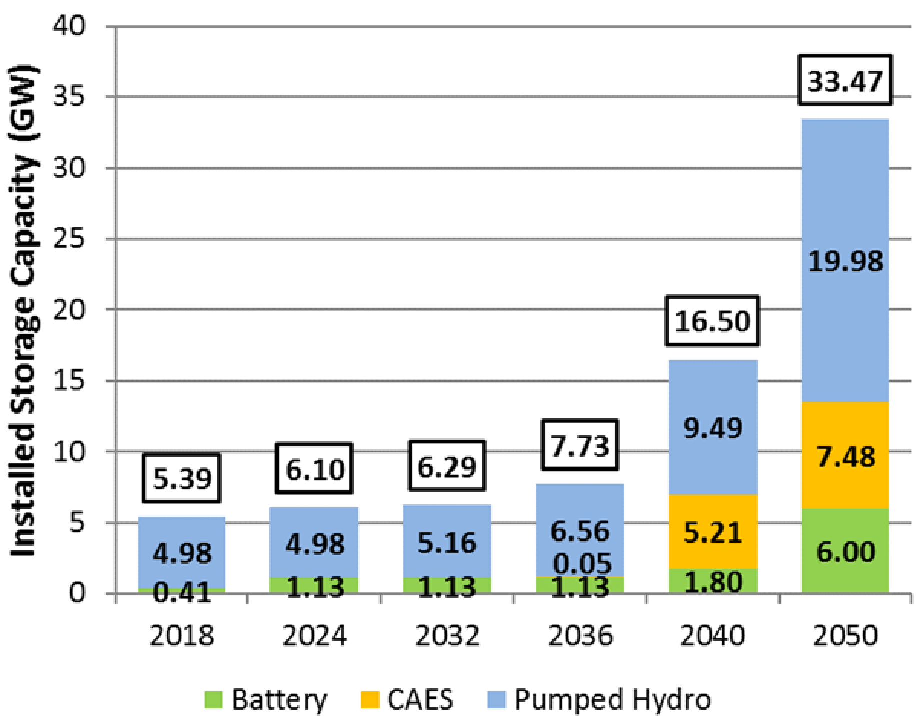

Figure 5: Grid-connected energy storage in the Western Interconnect as specified by ReEDS capacity expansion result (based on National 80% RPS scenario).

3. Run each storage and renewable scenario

Building on the basecases without storage or demand response, a wide variety of scenarios were developed to understand the impacts of storage, demand response (Flex-EY), retirements (see Table 2).

Table 2: Detailed list of scenarios run to compare the benefit of storage

Group	Configuration	Capacity (MW)	Parameters varied			
			Duration	Efficiency	Capacity Factor	Retirements
1.0	Base					None
1.1	Base+Storage	2000	1m	40%, 60%, 70%, 80%		None
1.2	Base+Storage	2000	1d, 2d, 1w, 2w, 1m	40%, 60%, 70%, 80%		None
2.0	Base+Retirements					batteries, NGCC, NGCT
2.1	Base+Storage+ Retirements	2000	1d, 2d, 1w, 2w, 1m	40%, 60%, 70%, 80%		batteries, NGCC, NGCT
2.2	Base+Storage	1500	1d, 2d, 1w, 2w, 1m	40%, 60%, 70%, 80%		None
3.0	Base+additional load					None
3.1	Base+Flex-EY	2000	1d, 2d, 1w, 2w, 1m	61.4%	40%, 65%, 90%	None

This creates a robust set of results that can be used to understand the important parameters and impacts from different permutations of those parameters.

4. Perform cost benefit assessment

The majority of analyses that are performed only look at the cost. That is because the benefit for long duration storage and demand response is difficult to calculate and represents the majority of work on this project. Combining the benefit results from the PLEXOS model runs, with cost information for each technology we create benefit to cost ratio (BCR). Table 3 contains the cost assumptions including a current and future cost which is broken down into a power cost and an energy cost.

Table 3. Cost of energy storage and hydrogen technologies assumed for this study.

		2020		2040	
Energy storage technology		**Power cost**	**Energy cost**	**Power cost**	**Energy cost**
CAES		$900/kW	$10/kWh	$900/kW	$10/kWh
PHS		$1500/kW	$100/kWh	$1500/kW	$100/kW
Vanadium RFB		$1500/kW	$500/kWh	$1000/kW	$250/kWh
P2G2P (Fuel cell)	PEM electrolyzer	$1600/kW	$3/kWh	$1000/kW	$3/kWh
	PEM fuel cell	$3000/kW		$2500/kW	
P2G2P (Turbine)	PEM electrolyzer	$1600/kW	$3/kWh	$1000/kW	$3/kWh
	Hydrogen-capable CT	$1100/kW		$1000/kW	

Results for 2020 to 2040 are presented in Figure 6. That figure shows the BCRs determined for various technology and duration combinations. Overall, the cost-benefit analysis finds that CAES and P2G2P-CT are the only energy storage technologies that shows a favorable BCR, under the conditions of this analysis[1]. CAES and P2G2P are favorable for 1 week or less and PHS for 1 day.

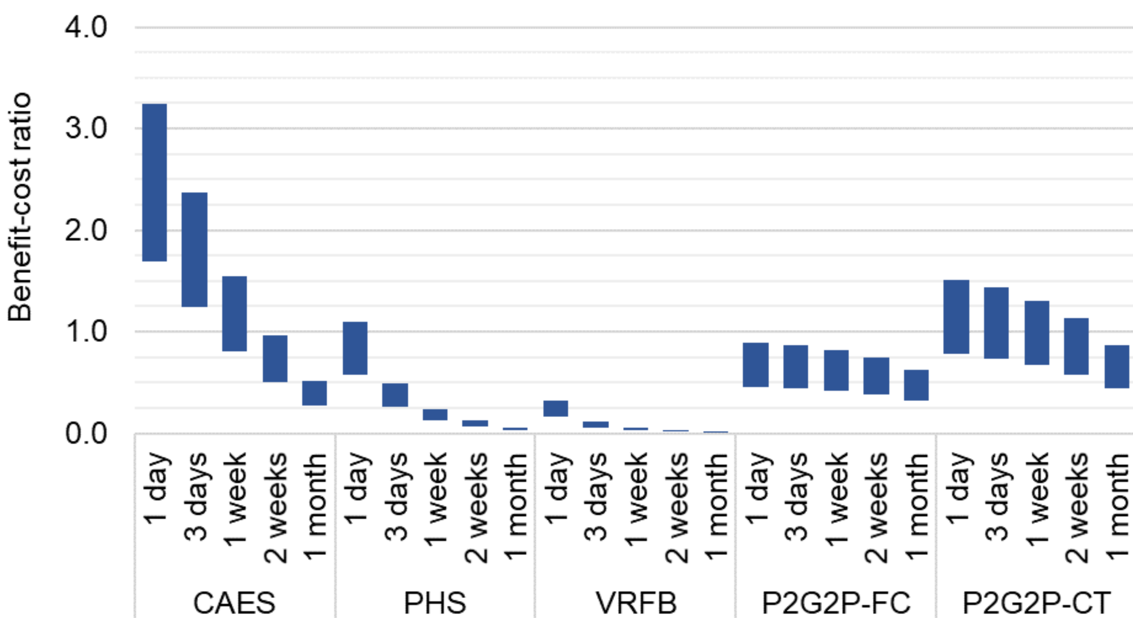

Figure 6. Benefit-cost ratio for long-duration energy storage scenarios (2020-2040 project lifetime).

[1] Before considering value from investment deferral, and costs for taxes; financing; and interconnection.

When the same technology scenarios are evaluated for the 2040-2060 timeframe, some scenarios move to favorable BCR, and the same general trends are observed. The VRFB, P2G2P-FC and P2G2P-CT cases are influenced by lower estimated future capital costs (Table 3), which increases the BCRs determined for those technologies (Figure 7). As a result of this change, the H2-CT (1 day) scenario moves from unfavorable BCR in 2020 to favorable BCR in 2040.

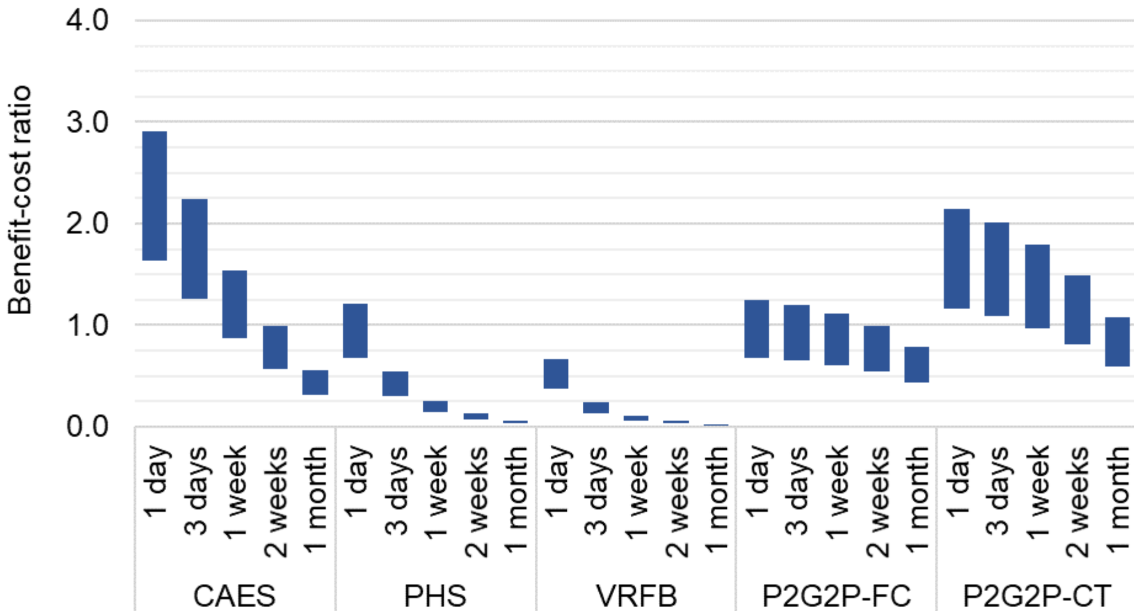

Figure 7. Benefit/cost ratio for long duration energy storage (2040-2060).

The following results are related to P2G systems. For projects installed in 2020, the analysis finds that P2G with merchant sale of hydrogen is economically favorable in many cases. This is particularly true for a sale price of $4/kg, for systems with shorter duration, and for higher capacity factor systems (Figure 8). Although the low capacity factor scenarios would allow the electrolyzer to operate more flexibly while still meeting the assumed constant hydrogen demand, the grid simulation did not identify system-wide benefit that offsets the cost of additional hydrogen storage for the modeled conditions.

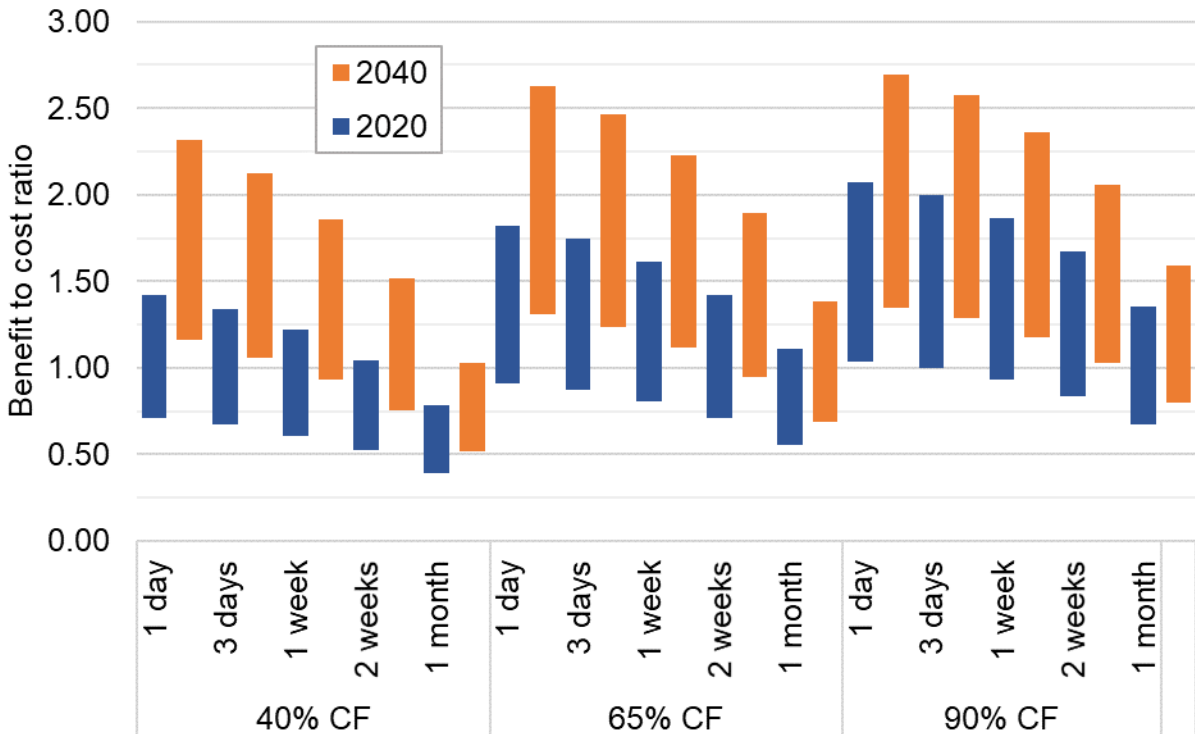

Figure 8. Benefit-cost ratio for flexible electrolyzer Power-to-Gas with hydrogen sale (ranging from $2-4/kg).

5. Prepare final report of findings

At the time this CRADA report was released, the final technical report was in the process of being prepared. The interim EPRI report was published under the title *Valuation of Hydrogen Technology on the Electric Grid Using Production Cost Modeling: 2018 Year-End Interim Report*, with report number 3002013731 at https://www.epri.com/research/products/000000003002013731. The final report, *Valuation of Hydrogen Technology on the Electric Grid Using Production Cost Modeling: Final Report* will ultimately be located at the following link: https://www.epri.com/research/products/000000003002016621.

Subject Inventions Listing:

None

ROI #:

None