Hydrogen & Fuel Cells Technical Advisory Committee

Hydrogen Enabling Renewables Working Group

Summary Report

October 2013

Introduction

In late 2010, the Hydrogen & Fuel Cell Technical Advisory Committee chartered a working group to examine the various ways in which hydrogen might serve as an enabler for high penetrations (greater than 50% nationally, or regionally, on an energy basis) of variable renewable energy in the United States. The Hydrogen Enabling Renewables Working Group (HERWG) began work in earnest in early 2011.

Comprised of both HTAC members and other representatives with significant hydrogen and fuel cell expertise, the Working Group benefited from the extensive knowledge, experience and insights of the following members:

- Frank Novachek (HTAC Member – Working Group Lead)
- Peter Bond (HTAC Member)
- Charles Freese (HTAC Member)
- Rob Friedland (Industry)
- Monterey Gardiner (DOE)
- Fred Joseck (DOE)
- Maurice Kaya (HTAC Member)
- Harol Koyama (HTAC Member)
- Jason Marcinkoski (DOE)
- Todd Ramsden (NREL)
- Bob Shaw (HTAC Member)
- Darlene Steward (NREL)
- George Sverdrup (NREL)
- Sandy Thomas (Consultant)
- Levi Thompson (HTAC Member)
- Daryl Wilson (Industry)

The first task was describing the future scenario where the US combined electric grid and transportation sector were powered with more than 50% renewables nationally or regionally on an energy basis. After significant discussion, the Working Group envisioned an environment characterized by the following attributes:

- Large amounts of variable off-peak renewable energy result in significant "spillage" or curtailments when it exceeds energy demand.
- Reductions seen in the cost of renewable energy versus traditional energy sources due to high volume production and technological advances
- Baseload power plants with lower turndown capabilities and better load following performance
- Large wind resources not near large load centers, requiring significant transmission investments
- Environmental concerns and transmission constraints limiting large scale central solar facilities, thereby influencing more distributed scale solar, using existing urban and suburban open spaces, including paved lots. (This type of resource will likely be interconnected to distribution grids).

▪ Distributed and utility-scale generators, such as stationary fuel cells, possibly becoming more economical and more efficient (both from energy conversion and CO2 perspectives) than traditional utility scale thermal resources.

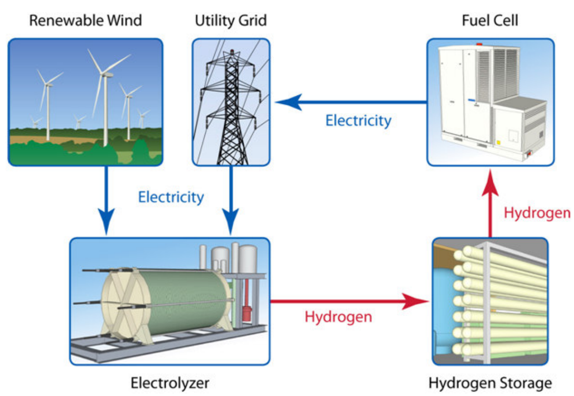
Given this potential future, the Working Group identified several potential applications for hydrogen and fuel cells to enable high penetrations of renewables, including:

▪ As a means for storing excess renewable energy and returning that energy to the electric grid when needed,
▪ As a supplement to natural gas system using excess renewable energy for hydrogen production to mix with natural gas,
▪ As an alternative energy transmission and distribution mechanism, and
▪ To improve renewable resource utilization through the production of vehicle fuel using excess renewable energy.

Because the elements of energy storage represent the fundamental building blocks for the other applications, the Working Group focused its attention in that area.

Energy Storage for Wind Integration

To better understand the economic drivers for hydrogen energy storage systems, the Working Group developed two basic models for evaluating hydrogen energy storage against other competing storage technologies. The first was a "Simple Model" based on the basis scheme shown below for utility scale wind energy storage:

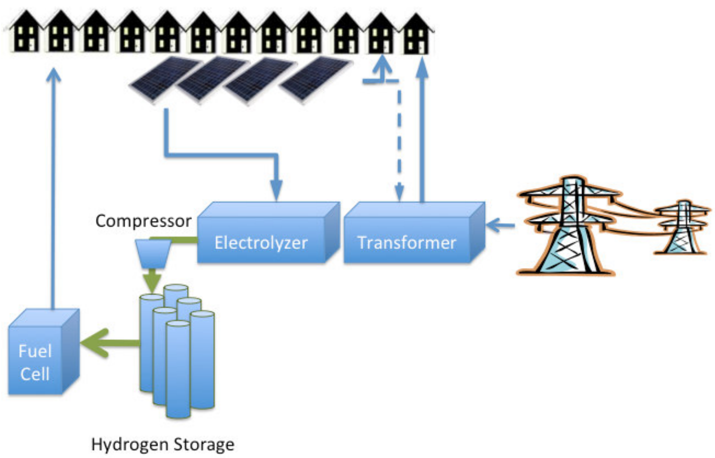


A whitepaper discussing the results of the analyses conducted using this model was developed by Dr. C.E. "Sandy" Thomas and is included as Appendix 1: Energy Storage for High Penetration Wind.

The conclusions from the "Simple Model" analyses found that hydrogen energy storage is competitive with all current energy storage technologies when the economic conditions make the capture of large amounts (on the order of weeks) of otherwise curtailed wind energy more valuable than curtailing it and letting the generation potential go to waste in order to maintain electric system stability and control. All in the Working Group agreed that such economic conditions could exist in the "high wind penetration" scenario contemplated (i.e., greater than 50% nationally, or regionally, on an energy basis), especially if coupled with higher renewable portfolio standards and/or other policies favoring renewable energy.

Community Energy Storage Systems for Load Leveling Solar Photovoltaics and Vehicle Refueling

The second was a model for evaluating community scale solar energy storage based on the following scheme:



A whitepaper discussing the results of the analyses conducted using this model was developed by Darlene Steward, from the National Renewable Energy Laboratory and is included as Appendix 2: Community Energy: Analysis of Hydrogen Distributed Energy Systems with Photovoltaics for Load Leveling and Vehicle Refueling.

The "Community Energy Model" analyses produced the following conclusions:

- There is a surprisingly good match between building load, PV system peak capacity and the number of vehicles that would be served in that size of community.
- Although results do not show a clear advantage for hydrogen energy storage load leveling or vehicle refueling, the economics could become competitive with larger systems (on the order of 15,000 kW peak capacity PV systems).
- The additional equipment for the hydrogen system hurts the economics for smaller systems.
- The flexibility of the hydrogen system configuration improves the economics for larger systems.
- For both hydrogen and electric vehicles, diverting more electricity from the PV system improves the economics, but the effect is more pronounced for the hydrogen system.

Other Energy Storage Approaches

Near the end of the of the Working Group's efforts, new information was being discussed about approaches to storing renewable energy as hydrogen in the nation's existing natural gas system. In Europe there are now more than twenty so called "power-to-gas" hydrogen energy storage demonstration projects which have been launched in the last 18 months – more than any other technology platform for utility scale storage. Though the Working Group did not delve into this hydrogen storage pathway in significant detail, the concept is intriguing to several of its members and could possibly have applications for the U.S.

Overall Conclusions & Recommendations

As the nation's renewable generating capacity (solar and wind) expands to deliver a significant fraction of the total electric energy generated (somewhere greater than 30 percent on an energy basis nationally), both short and long term energy storage will likely be very desirable, if not required. The Working Group considered a scenario where the penetration of renewables was 50% on an energy basis. Under this scenario, the Working Group assumed that environmental policies would likely be in place influencing grid economics to maximize the use of renewable energy, such that using curtailment as a means to maintain grid stability would be much a much more costly control measure than it is today. If that is the case, there would conceivably be economic benefits to storing weeks or more of otherwise curtailed renewable energy during peak output periods in high penetration renewable regions for use during periods when the stored renewable energy can be delivered in order to reduce the need for greenhouse gas emitting generation.

Hydrogen technology, as shown by "Simple Model" study (Appendix 1), has the most economical and greatest storage capacity for absorbing and redeploying energy generated from renewable generation when compared to batteries, compressed air energy storage and pumped hydro storage solutions, when the storage requirement is in terms of weeks or longer. Because of this, hydrogen energy storage could be an essential contributor to enabling renewables at the high penetrations contemplated by the Working Group.

Although results do not show a clear advantage for hydrogen energy storage load leveling or vehicle refueling at smaller scales studied in this effort, the economics could become competitive with larger systems, especially for larger systems (on the order of 15,000 kW peak capacity PV systems). Such a system would also be capable of providing both fully renewable fuel and electric grid stabilization benefits.

Continuing assessment of the economic viability of hydrogen production as a renewable energy storage pathway should be a high priority for DOE and the renewable/electric industry, working in partnership.

Recommendations

Energy Storage for Wind Integration:

- Determine if there are national policies being considered that would significantly increase renewable penetrations as a means to reduce greenhouse gas emissions.
- Conduct system analyses including and excluding long-term storage using policy scenarios identified, and from these analyses, estimate the value of hydrogen energy storage to the overall system under those scenarios.
- Determine what value the government could assign to otherwise curtailed renewables to make multi-day/week scale hydrogen (and other) energy storage economical.

Community Energy for Load Leveling and Vehicle Fueling:

- Conduct sensitivity analyses to determine what conditions are necessary for a hydrogen system to compete with electric battery system for fueling FCV and EV vehicles, respectively, with solar PV energy.
- Determine the community scale at which hydrogen storage competes with battery storage for solar PV load leveling and vehicle fueling.

Other

- Consider investigating potential U.S. applications for "power-to-gas" energy storage systems and, if deemed to have potential, initiate a dynamic economic study (supported by the relevant teams at DOE, the national laboratories) to evaluate the system wide and integrative benefits of such hydrogen storage system for U.S. markets.

Appendix 1

Energy Storage for High Penetration Wind

Dr. C.E. "Sandy" Thomas

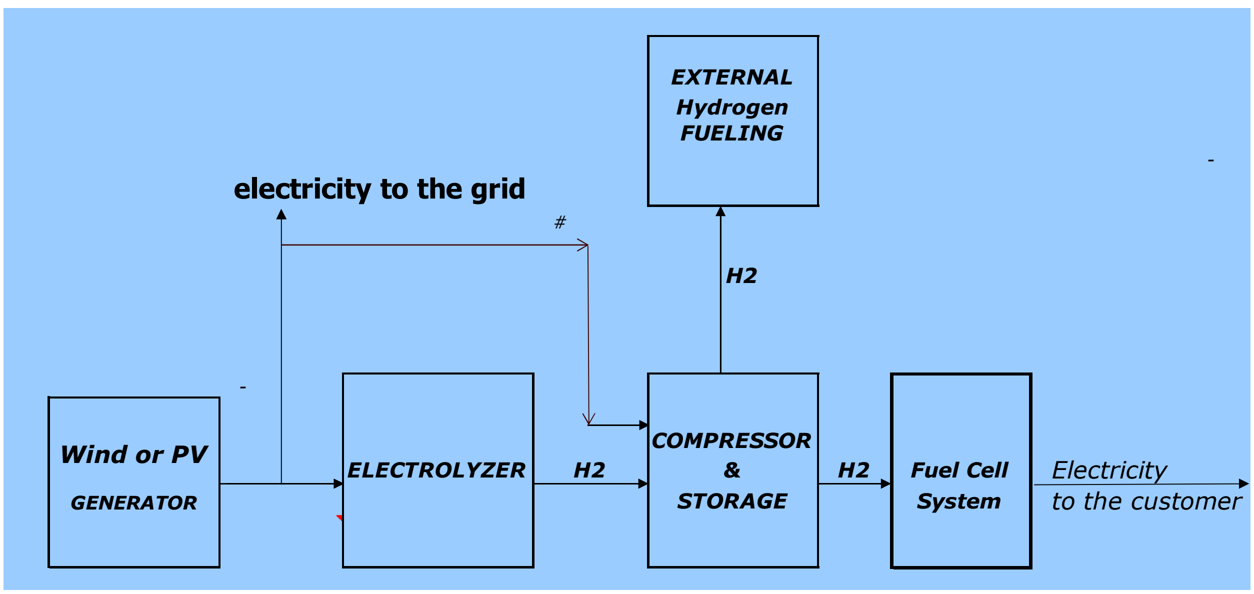
Energy Storage for High Penetration Wind

Introduction -

This work was conducted on behalf of an HTAC subcommittee chartered with the task of determining if hydrogen storage would enable wider grid penetration[1] of intermittent renewable energy sources. Both solar energy and wind farm systems would benefit from large-scale energy storage due to three factors, especially with large utility grid penetration of intermittent renewables:

- Renewable energy utilization is often limited by **electrical transmission line constraints** between the source and the electrical demand.
- Renewable energy use is sometimes limited by the **lack of adequate electricity load** at the time of large renewable generation potential.
- The fossil **fuel generators** (typically natural gas turbines) used to "Firm" intermittent renewable sources **can increase greenhouse gas emissions and local pollution** including increased NOx and SOx emissions compared to using those fossil sources all the time.[2]

The basic flow diagram for the model is shown below; renewable electricity is used to generate hydrogen with an electrolyzer. That hydrogen is then stored and either used to fuel vehicles or to generate electricity at a later time. Thus excess renewable electricity can be stored for later use instead of wasting this electricity when there is no load or when transmission capacity is limited.



[1] The hydrogen enabling renewables working group (HERWG) chaired by Frank Novachek of Xcel Energy

[2] For example, Post speculates that GHGs, NOx and SOx emissions from natural gas turbines operating at part power (where efficiency decreases) used to fill in the gaps in intermittent renewable generators may be higher with the intermittent renewable plus gas turbine than for a system that uses a NG turbine to supply 100% of the load; in this case, adding renewables may actually degrade the environment.; storing the excess renewable energy as hydrogen and "firming" intermittents with hydrogen-generated electricity would eliminate this possibility. (see: Willem Post, "Wind energy does little to reduce GHG emissions," available at http://theenergycollective.com/willem-post/64492/wind-energy-reduces-co2-emissions-few-percent .

This report compares three types of bulk energy storage:

- Battery storage
- Hydrogen storage
- Compressed air energy storage (CAES)

We do not address pumped hydro storage, since sites to store large reservoirs of water are limited.

Wind Energy

Wind energy is the most problematic, since wind resources tend to peak at night in the winter months, while electrical loads typically peak in late summer afternoons.

Y. H. Wan of NREL has explored multi-year wind output data from four wind farms at these locations[3]:

- Lake Barton, Minnesota (104 MW peak power)
- Storm Lake, Iowa (113 MW peak)
- Blue Canyon, Oklahoma (75 MW)
- Trent Mesa, Texas (150 MW)

To back up these intermittent wind sources with hydrogen storage, the fuel cell output power should be at least equal to the average wind power. The average capacity factor for wind farms in the US was 33% according to data from 2011[4]. Thus the average wind power would vary between 25MW and 50 MW, so the fuel cell system used to convert stored hydrogen back to electricity should have a peak power rating of at least 25MW or larger for higher power wind farms; we use 25-MW fuel cell systems in this model.

Battery and CAES Input Data

The battery data for this model were taken from an EPRI report[5]. The CAES (compressed air energy storage) data were taken from another EPRI presentation[6].

[3] Y. H. Wan, *Long-Term Wind Variability*, NREL/TP=5500-53637, January 2012; available at: http://www.nrel.gov/docs/fy12osti/53637.pdf
[4] R. Wiser & M. Bolinger, *2011 Wind Technologies Market Report*, Lawrence Berkeley Laboratory, August 2012; - available at: http://www1.eere.energy.gov/wind/pdfs/2011_wind_technologies_market_report.pdf -
[5] D. Rastler, *Electricity Energy Storage Technology Options: A White Paper Primer on Applications, Costs, & Benefits*, - Electric Power Research Institute, Report # 1020676, December 2010, Table 4; available at: - http://large.stanford.edu/courses/2011/ph240/jiang1/docs/rastler.pdf
[6] R. Schainker, *Compressed Air Energy Storage (CAES)-Executive Summary*, (Electric Power Research Institute), August 2010, Slide #8, shown on the next page, available at http://disgen.epri.com/downloads/EPRI%20CAES%20Demo%20Proj.Exec%20Overview.Deep%20Dive%20Slides.by%20R.%20Schainker.Auguat%202010.pdf

Table 1. Model input data for battery and compressed air energy storage systems[7]

	$/kW		$/kWh		Efficiency	
	Low	High	Low	High	Low	High
Adv PbA	950	1590	425	475	90%	85%
Zn /Br	1450	1750	290	350	60%	60%
Fe/Cr	1800	1900	360	380	75%	75%
Zn/Air	1440	1700	290	340	75%	75%
NaS	3100	3300	520	550	75%	75%
CAES-Above	800	900	200	240	90%	90%
CAES-below	640	730	1	2	90%	90%
Li-Ion	1085	1550	900	1700	92%	87%

HTAC simple model EPRI(Rev10-9-12-25MW).XLS, WS 'Battery Data' H-13;11/2/2012

Two different cost methodologies were used in these EPRI reports: the battery cost data depend only on the energy ($/kWh) costs times the stored energy[8], while the CAES data from Schainker depend on both the power level and the energy stored.

Technology	$/kW	+	$/kW-H*	x	H	=	Total Capital, $/kW
Compressed Air							
- Large, salt (100-300 MW)	640-730		1-2		10		650 to 750
- Small (10-20MW) AbvGr Str	800-900		200-240		2		1200 to 1380
- Small (10-20MW) AbvGr Str	800-900		200-240		4		1600 to 1860
Pumped Hydro							
- Conventional (1000MW)	1500-2000		100-200		10		2500 to 4000
Battery (10 MW)							
- Lead Acid, commercial	420-660		330-480		4		1740 to 2580
- Advanced (target)	450-550		350-400		4		1850 to 2150
- Flow (target)	425-1300		280-450		4		1545 to 3100
Flywheel (target) (100MW)	3360-3920		1340-1570		0.25		3695 to 4315
Superconducting (1 MW) Magnetic Storage	200-250		650,000 - 860,000		1/3600		380 to 490
Super-Capacitors (target)	250-350		20,000 - 30,000		1/360		310 to 435

* This capital cost is for the storage "reservoir", expressed in $/kW for each hour of storage. <u>For battery plants, costs do not include expected cell replacements.</u> The cost data are in 2009 $'s and are updated by EPRI periodically. Costs do not include permits, all contingencies, interest during construction and the substation.

Figure 1. CAES cost data; Slide #8 from the R. Schainker presentation (reference 5 above)
[Battery cost data from this slide were not used in this model.]

[7] The Li-ion battery costs were taken from the EPRI multi-megawatt systems for "energy storage for Utility T&D support applications"; their Li-ion costs for energy storage for "ISO fast frequency regulation and renewables integration" were even higher at $4,340/kWh to $6,200/kWh, all taken from the EPRI Table 4 in reference 5 above.
[8] EPRI apparently folded in the power demand charges into an overall $/kWh cost estimate.

Hydrogen System Input Data

Table 2. Input data for hydrogen/FC storage system coats and efficiencies

	Near- term	medium-term	Long-term
Electrolyzer HHV efficiency*	79.3%	81.7%	87.7%
Electrolyzer Capex**	$1500 /kW	$1000 /kW	$380 /kW
Compressor efficiency	92%	92%	92%
Compressor Capex ($/kg/day)	232	232	232
FC HHV efficiency	39.7%	44.8%	49.0%
FC capex***	$1000 /kW	$750 /kW	$500 /kW
H2 (above ground) tank capex	$807 /kg	$760 /kg	$700 /kg
H2 (below ground) Storage capex ($/kg)	2.5 to 7	2.5 to 7	2.5 to 7
H2 Dispenser Capex	$ 75,000	$ 60,259	$ 50,216

* Norsk Hydro 50.7 kWh/kg = 77.7% HHV eff.; Giner/ProtonOnsite: 88.9%

** NREL Independent Panel Review; (BK-6A1-46676; Sept 2009)

***DOE Targets: $750/kW (2008); $650/kW (2012); $550/kW(2015); $450/kW (2020)

HTAC ERWG simple model EPRI (Rev 10-9-12 - 25MW).XLS, WS Assumptions D16;12/13/2012

The below-ground storage costs are based on geologic storage in underground caverns, acquifiers or depleted natural gas fields. The total system storage costs were provided by the National Renewable Energy Laboratory[9]; these costs vary with the total storage capacity as shown in Figure 2 from $2.50/kg for very large caverns holding more than 4 million kgs of hydrogen to $7/kg for storage of less than 350,000 kg of hydrogen.

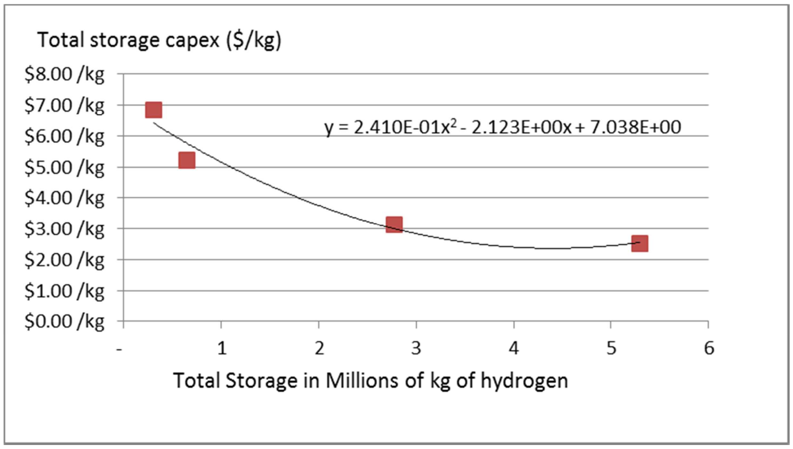


Figure 2. Underground (cavern) hydrogen storage costs as a function of storage capacity

[9] Private communication from Darlene Steward at NREL

Table 3.Annual O&M and Replacement input data

	Replacement Costs		
	Replacement Interval	*Fraction Replaced*	*Annual O&M*
	(Years)		*(% of Capex)*
Electrolyzer	*7*	*25%*	*2.18%*
Compressor	*10*	*100%*	*2.50%*
Storage System			*0.02%*
Fuel Cell System	*15*	*30%*	*2.00%*
Dispenser System			*0.90%*

HTAC simple model EPRI (Rev 10-9-12--25MW).XLS, WS 'O&M' D-13;11/9/2012

Model Assumptions

The model assumes that the owner of the energy storage system pays 5.4 cents/kWh to purchase wind power. The owner then stores the energy, and regenerates electricity when demand is high, selling that peak power electricity at a rate that will earn a 10% real, after-tax return on the storage system investment.

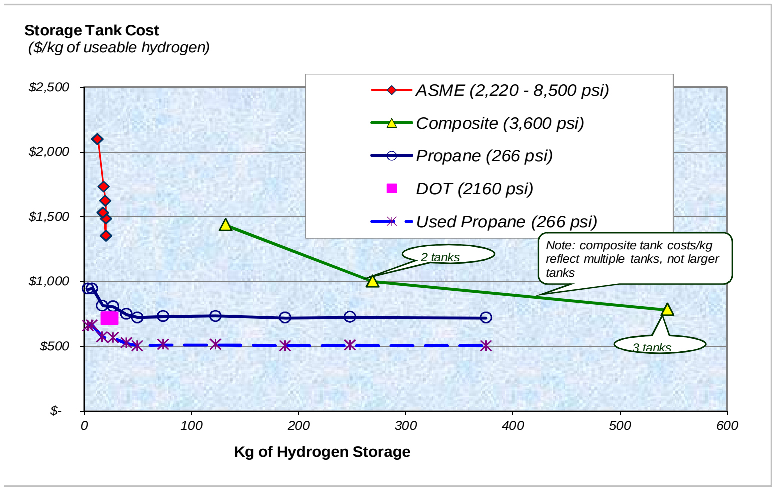
Table 4. Financial input data for the model

Inflation rate	*1.9%*
Marginal income tax rate	*38.9%*
Real, after-tax Rate of return required	*10%*
Depreciation schedule	*Declining balance*
Annual capital recovery factor	*11.79%*

HTAC simple model EPRI (Rev 10-9-12--25MW).XLS, WS 'Dashboard (Flow Diagram) D-94;11/9/2012

<u>Stored Electricity Price Estimates from various storage systems</u> -

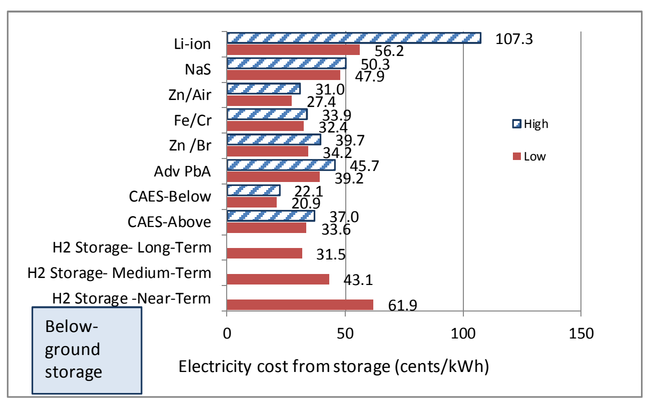
The stored electricity costs were set to pay for all operating costs[10] for the storage system including the purchase of the wind energy at a price of 5.4 cents/kWh, the capacity-weighted average cost[11] of US wind in 2011 plus an extra amount such that the owner of the storage system earns a 10% real, after-tax



H2 Storage Tank Costs.XLS; I85 10/12/2012

Figure 3. Examples of above-ground hydrogen tank costs circa 2009

return on the investment in the storage system. The price of electricity is set to assure this 10% real ROI with the economic parameters in the model. (Table 4). With the battery & hydrogen storage system data, the estimated costs for electricity generated from stored energy are summarized in Figure 4. The scale is expanded in Figure 5 to show the lower cost storage systems (excluding the high-cost Li-ion system.) Two costs are shown for the battery and CAES storage systems, corresponding to EPRI's high and low cost estimates.



HTAC simple model EPRI(Rev10-9-12-25MW).XLS, WS 'DashBoard' BK-317; 11/12/2012

Figure 4. Cost of stored electricity (one day's storage) with natural gas at $7/MBTU (used for CAES only)

[10] Annual O&M and periodic replacement costs for electrolyzers, fuel cells, compressors, etc.; taxes and insurance; -construction loan costs (first year only; two-year construction period assumed). -

[11] See reference #3 -

The potential lowest cost system according to the EPRI report is the Zn/Air system that is not currently commercially available. The long-term hydrogen storage system cost at 31.5 cents/kWh is competitive with the future Zn/air battery system at 27.4 to 31 ₵/kWh, and less than the current commercial battery systems (Li-ion, NaS and PbA)[12].

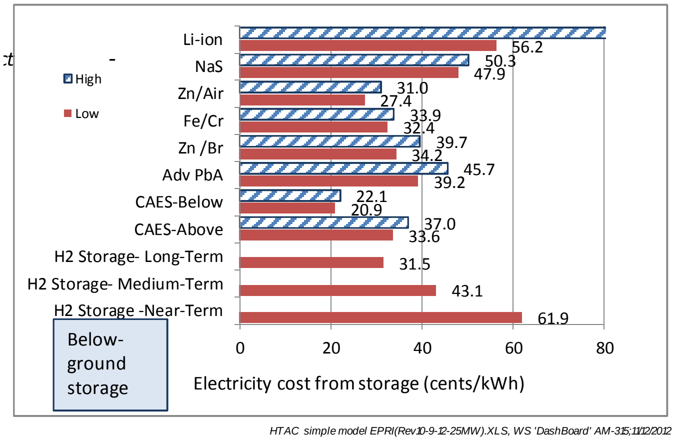


Figure 5. Cost of stored electricity to yield 10% RATROI (Same as Figure 4 with expanded scale)

Figures 4 & 5 are for underground (cavern storage of hydrogen). As shown in Figure 6, above-ground storage in pressurized hydrogen tanks is also economic. Above-ground storage offers more flexibility, since it does not require location near geologically available underground sites. Hydrogen storage in tanks is competitive in the long-term (33.2 cents/kWh) with current commercially available battery systems such as Li-ion, NaS and PbA. Hydrogen long-term costs are also less than above-ground CAES storage systems.

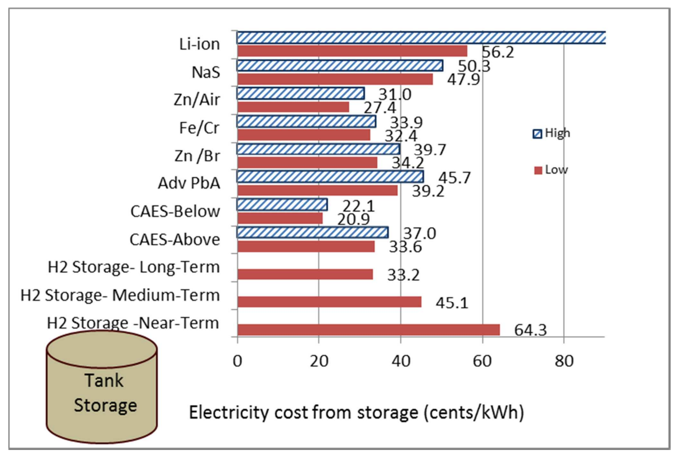


Figure 6 . Stored electricity costs for above-ground hydrogen storage in tanks (one day's storage)

The hydrogen storage tank cost estimate for the long-term ($700/kg) could be based on either low-pressure propane tanks that are priced at $724/kg new or $506/kg (used) as shown on Figure 3 or existing Lincoln Composites "Titan" composite hydrogen tanks that were selling for $700/kg in quantities of three in 2009.

<u>Need for longer-term storage</u>

Energy storage times longer than one day are highly desirable for wind energy. For example, Figure 7 shows the spectra of wind energy from one source[13]. In addition to the spectral peak at one day duration, there is a dominant peak at 4 day intervals, but this 4-day peak is usually associated with sites near an ocean. And there is a dominant peak at one year, indicating a strong annual oscillation in wind energy, peaking in the winter and diminishing in the summer months.

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[12] Note that all hydrogen electricity prices quoted here should be compared with peak electricity rates, since the electricity generated from stored hydrogen can be supplied during peak demand periods.
[13] Source: Green Rhino Energy http://www.greenrhinoenergy.com/renewable/wind/wind_characteristics.php

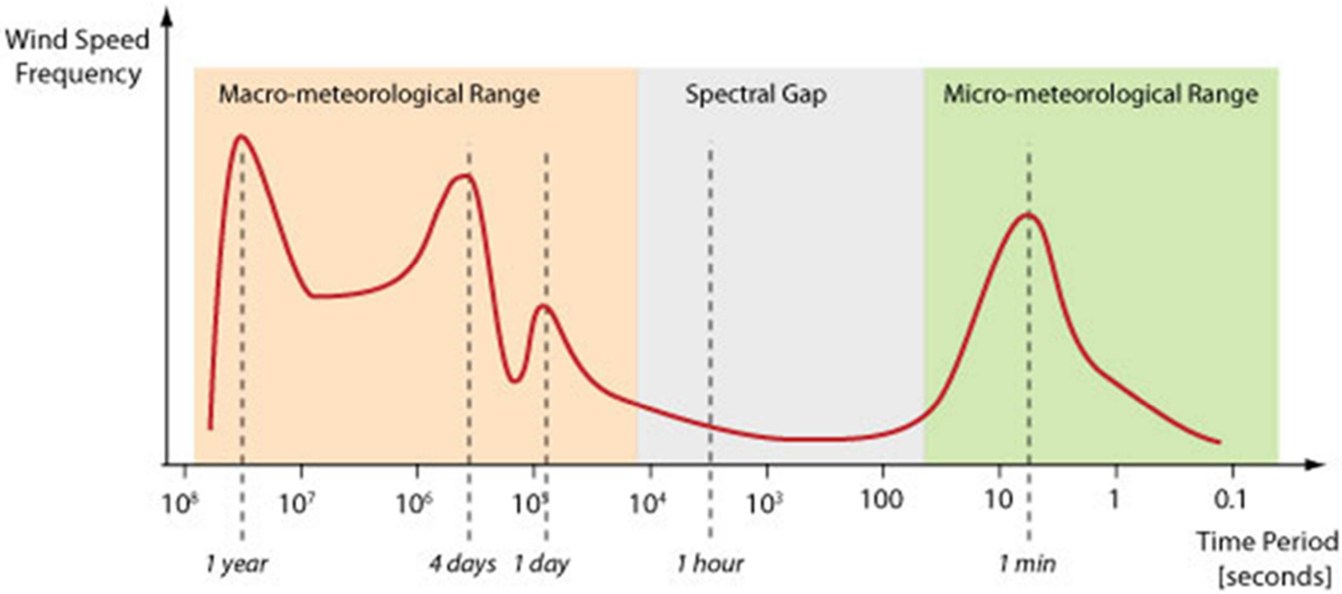


Figure 7. Spectral energy distribution for wind energy

Specific wind annual energy profiles[14] are shown in Figures 8-11. Figure 8 shows 10 years data and the 10-year average for a 104-MW wind farm in Lake Benton, Minnesota. The average peak wind energy in the winter is 1.64 times the annual wind energy in the summer months. Note also that the annual peak to minimum wind energy often varies much more than the 10-year average.

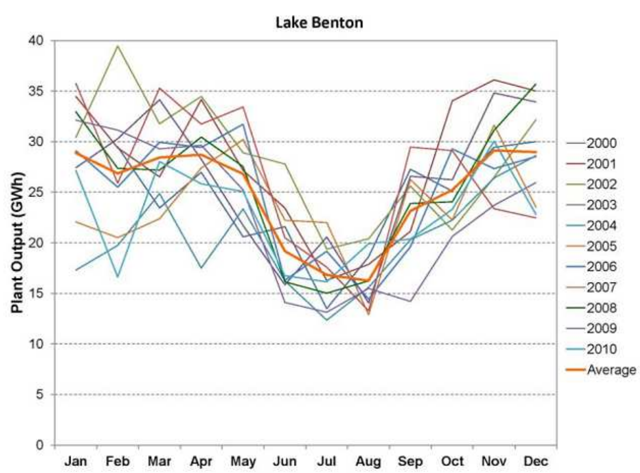


Figure 8.Ten years of wind energy produced at the 104-MW Lake Benton, Minnesota wind farm (winter wind averages 1.6 time summer wind)

Figure 9 shows 7 years' wind energy data from the 75-MW wind farm at Blue Canyon, Oklahoma. The 7-year average - has a peak winter energy level that is **2 times** the summer energy level, again with large annual deviations from the average.

Finally, Figure 10 shows similar annual data for a 113-MW wind farm at Storm Lake, Iowa, where the winter peak energy output is **2.4 times** the average winter energy output.

From these data it is apparent that there would be significant advantage if the excess winter wind energy could be stored until the summer months, when demand is typically higher to meet air conditioning loads.

[14] See Reference #1 (Wan)

Wind energy is also frequently higher at night than during the day, as illustrated in Figure 11 for a 150-MW wind farm in Trent Mesa, Texas.

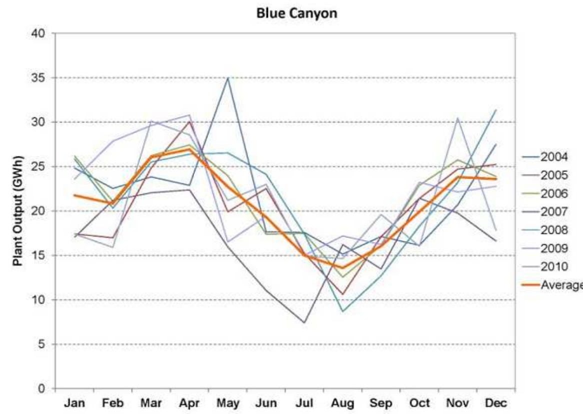


Figure 9. Seven years of wind energy data from the 75-MW Blue Canyon, Oklahoma site (winter energy is 2 times the summer wind energy)

Stored electricity costs as a function of storage time

The required price of stored electricity to achieve the 10% ROI goal are shown in Figure 12 as a function of the storage time. For a few days of storage, hydrogen storage is less expensive than the lowest cost battery option (Zn/air), even for the near-term hydrogen system. For storage times longer than 6 days, the long-term hydrogen costs are less than the cost of CAES storage with natural gas at \$7/MBTU[15].

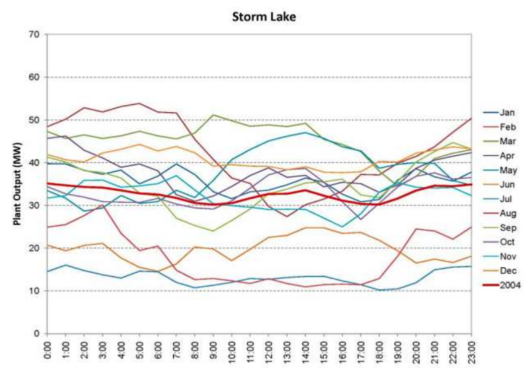


Figure 10. Ten years of wind energy data from the 113-MW Storm Lake, Iowa wind farm (Winter wind energy is 2.4 times the summer wind energy)

US Natural gas prices have been trending down with the discovery and production of gas from shale formations as shown in Figure 13 for industrial users, with industrial gas prices falling below \$4/MBTU. However, the EIA in their latest (2012) Annual Energy Outlook is projecting that industrial gas prices will rise[16] as shown in Figure 14. projecting future prices in the \$4.50/MBTU to \$8/MBTU range.

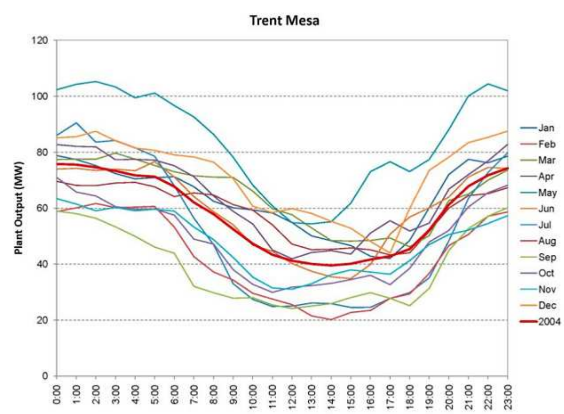
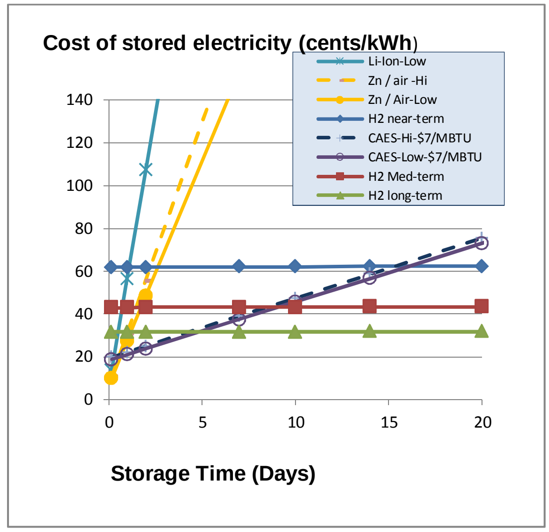


Figure 11. Average hourly wind energy at Trent Mesa, Texas, showing more wind energy at night than during the day

The impact of lower natural gas prices on the stored electricity prices from CAES is shown in Figure 15. Even if natural gas fell to \$3/MBTU,

[15] Natural gas is used to heat the compressed air gas in curr
[16] John Hofmeister (the former President of Shell Oil USA an
and fuel cell Technology Advisory Committee), points out th
as high as 50% per year, indicating that these wells will have to be replaced (or re-fractured) frequently to keep the gas flowing, thereby increasing shale gas costs over time.

hydrogen storage would be less expensive than CAES for storage times longer than 60 days in the near-term; 30 days in the mid-term, and 14 days in the long-term as shown in Figure 15. Note again that these prices for stored energy should be compared with peak electricity rates, since the stored energy can be sold at any time.



HTAC simple model EPRI (Rev 10-9-12 - 25MW.XLS, WS 'DashBoard' AK-355;11/12/2012

Figure 12. Electricity price to earn 10% ROI for longer term storage with natural gas at $7/MBTU

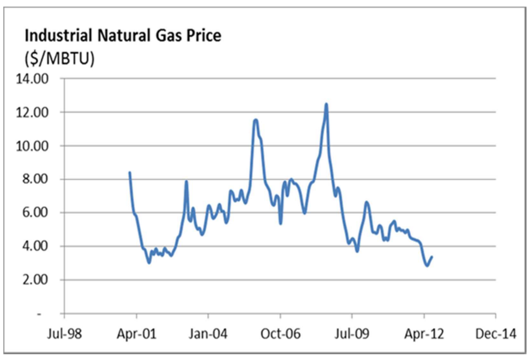
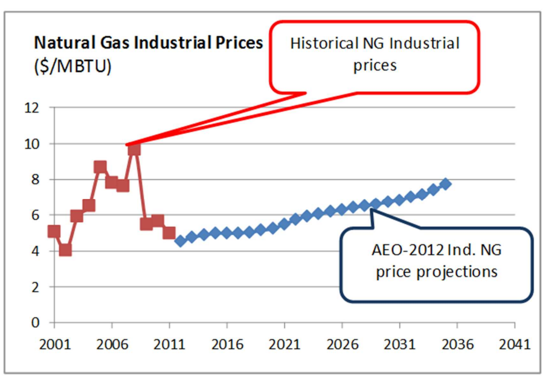
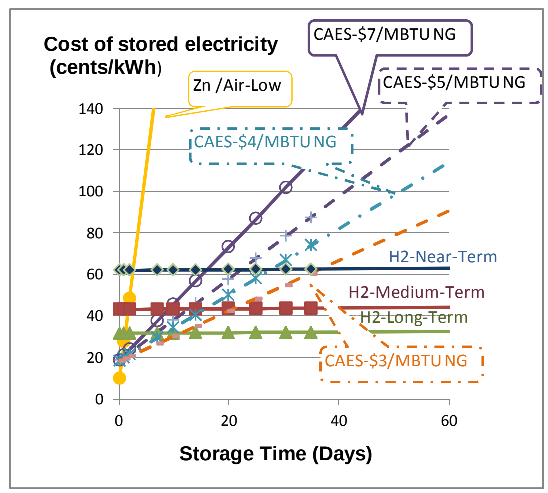


Figure 13. Recent US Industrial Natural Gas Prices



Story Economics.XLS; Tab 'AEO2012 Fuel costs'; - 40 10/5/2012

Figure 14. Industrial natural gas prices projected by the EIA in their 2012 Annual Energy Outlook (AEO)



HTAC simple model EPRI (REV 7-5-12-Energy only).XLS, WS 'DashBoard' AH-410;11/13/2012

Figure 15. Stored electricity prices to yield a 10% real, after-tax ROI including variable natural gas prices for CAES storage; both hydrogen and CAES prices are for underground storage.

<u>Longer-Term Hydrogen CHHP systems</u>

In the future, high temperature stationary fuel cells such as molten carbonate (MCFCs), phosphoric acid fuel cells (PAFCs) or solid oxide fuel cells (SOFCs) could provide extra revenue to the storage system owner by supplying both heat and hydrogen—combined heat, hydrogen and power (CHHP) systems. We consider four estimates for future SOFC costs:

1. Strategic Analysis has estimated a mass production cost of $700/kW for 100kWe SOFC systems,

2. - the HTAC subcommittee has chosen \$500/kW as the long-term price estimate for FC systems,
3. - the DOE's SECA has set a "stretch" target of \$400/kW for SOFCs, and
4. - Rivera-Tinoco et al. have estimated a SOFC manufactured cost[17] of \$100/kW or less for 250 kW modules for cumulative production volumes less than 1 MW as shown in Figure 16. This is the manufactured cost estimate, based on inputs from three fuel cell companies[18]. To this we add a multiplier factor of 1.5 to arrive at an estimate of the selling price[19] that the hydrogen storage operator would have to pay, or an estimated long-term price of \$150/kW for an advanced SOFC system in production.

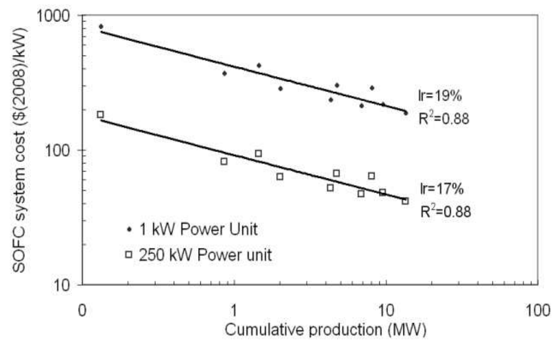


Figure 16. Estimated manufacturing *cost* for SOFC systems by Rivera-Tinoco et al.

Strategic Analysis has estimated the mass production costs of Stationary PEM and SOFC systems (Table 5)[20]. They are projecting that 100-kWe low temperature PEM fuel cell systems (including reformer and AC inverter) could be produced for \$771/kWe, and costs as low as \$402 to \$440/kWe for 100 kWe SOFC systems might be achieved in very

Table 5 . Strategic Analysis estimated costs of stationary fuel cell systems in mass producion.

LT PEM Systems	1 kWe	5 kWe	25 kWe	100 kWe
100 sys/yr	\$10,106	\$3,182	\$1,180	\$771
1,000 sys/yr	\$7,854	\$2,556	\$941	\$637
10,000 sys/yr	\$6,618	\$2,185	\$760	\$486
50,000 sys/yr	\$6,032	\$1,935	\$658	\$428
HT PEM Systems	**1 kWe**	**5 kWe**	**25 kWe**	**100 kWe**
100 sys/yr	\$10,130	\$3,483	\$1,363	\$1,062
1,000 sys/yr	\$7,895	\$2,840	\$1,181	\$867
10,000 sys/yr	\$6,699	\$2,448	\$941	\$680
50,000 sys/yr	\$6,101	\$2,132	\$816	\$606
SOFC Systems	**1 kWe**	**5 kWe**	**25 kWe**	**100 kWe**
100 sys/yr	\$11,830	\$3,264	\$981	\$532
1,000 sys/yr	\$6,786	\$2,168	\$671	\$440
10,000 sys/yr	\$5,619	\$1,862	\$599	\$414
50,000 sys/yr	\$5,108	\$1,709	\$570	\$402

Figure 5: Summary Table of System Cost Results, \$/kWe

[17] R. Rivera-Tinoco, K. Schoots & B.C.C. van der Zwaan, *Learning Curves for Solid Oxide Fuel Cells* (Energy Research Center of the Netherlands.), Figure 4; available at: http://www.energy.columbia.edu/sitefiles/file/Learning%20Curves%20for%20Solid%20Oxide%20Fuel%20Cells.pdf

[18] HC Starck, Topsoe and Versa. -

[19] This 1.5 multiplier assumes that 80% of the production cost is purchased parts and materials with a 20% General - & Administrative (G&A) markup, and labor has a 25% G&A markup plus a 40% overhead markup, and the sum of all - these costs is marked up by 15% to account for profit; the net result is a 1.5 times markup on the manufactured - cost to obtain a price. -

[20] Brian James, Andrew Spisak & Whitney Colella, "Manufacturing Cost Analysis of Stationary Fuel Cell Systems," - Strategic Analysis, Arlington, Virginia September 2012. -

large production volumes (1,000 to 50,000 systems per year.)

For these longer term systems, we have also reduced the estimated cost of the electrolyzer based on the 2009 NREL independent review of electrolyzer costs[21]. The NREL independent review used data from six electrolyzer companies[22] and reported a manufacturing cost estimate of $380/kW for an electrolyzer supplying 1,500 kg/day, but this cost also included the compression, storage and dispensing equipment at the fueling station. The DOE's H2A model lists a total cost of $1.263 million for the electrolyzer, transformer/rectifier and other electrolyzer balance of plant, out of a total cost of $2.254 million; so the electrolyzer system accounts for 56% of the reported cost of $380/kW. Applying this factor implies an electrolyzer system cost of$213/kW, or an estimated price of $320/kW after applying our 1.5 markup factor to translate manufacturing *cost* to selling *price* to the hydrogen storage system operator. In addition, Sunita Satyapal, the DOE's Hydrogen Program Manager, announced at the 2011 Annual Merit Review[23] that Giner and Proton had demonstrated an electrolyzer production cost of $350/kW. The assumptions for these SOFC systems are compared with the base case hydrogen long-term data in Table 6 (See Table 2 for the cost and efficiency assumptions for the Near- and Medium-Term hydrogen options.)

Table 6. cost and efficiency values used for three different long-term hydrogen storage scenarios

Long-Term Hydrogen Assumptions	Base Case	SOFC-Low	SOFC-High
FC Capex	$500 /kW	$150 /kW	$700 /kW
FC HHV Efficiency	49.0%	55.0%	55.0%
Electrolyzer HHV Efficiency	87.7%	87.7%	87.7%
Electrolyzer Capex	$380 /kW	$320 /kW	$320 /kW

HTAC simple model EPRI (Rev 10-9-12 -25MW).XLS, WS Assumptions D47; 11/11/2012

<u>Hydrogen Fuel Revenue</u>

[21] J. Genovese, K. Harg, M. Paster, & J. Turner, *Current (2009) State-of-the-Art Hydrogen Production Cost Estimate Using Water Electrolysis*, NREL/BK-6A1-46676, September 2009. -

[22] Avalence, Giner, H2 Technologies, Hydrogenics, IHT and Proton Energy (now called Proton Onsite) -

[23] As reported by Sunita Satyapal in her 2011 AMR presentation, available at: - http://www.hydrogen.energy.gov/pdfs/review11/pl003_satyapal_joint_plenary_2011_o.pdf

In addition to supplying electricity, the hydrogen storage system can provide fuel for fuel cell electric vehicles (FCEVs). In general, hydrogen is worth more as a FCEV fuel than as a source of electricity. For example, with the base case long-term hydrogen system, hydrogen can be sold at $5.11/kg, which is equivalent to gasoline selling at $2.17/gallon if used in a conventional car[24]. The EIA is projecting that the average gasoline price in 2015 will be $3.81/gallon. In the model, we assume that 50% of all cars are hybrid electric vehicles (HEVs), and hydrogen is priced such that the FCEV owner will pay the same cost per mile as the average gasoline vehicle owner (50/50 split between HEVs and ICVs.) The revenue from selling hydrogen as a fuel then reduces the necessary price of stored electricity in order for the hydrogen storage system owner to make a 10% real, after-tax return on investment in addition to paying all hydrogen storage system operating costs. We assume that the storage facility sells 1,530 kg/year[25] of hydrogen fuel[26]. This corresponds to the hydrogen demand of a mature hydrogen fueling station that fuels 300 cars/day, a modern high-volume fueling station.

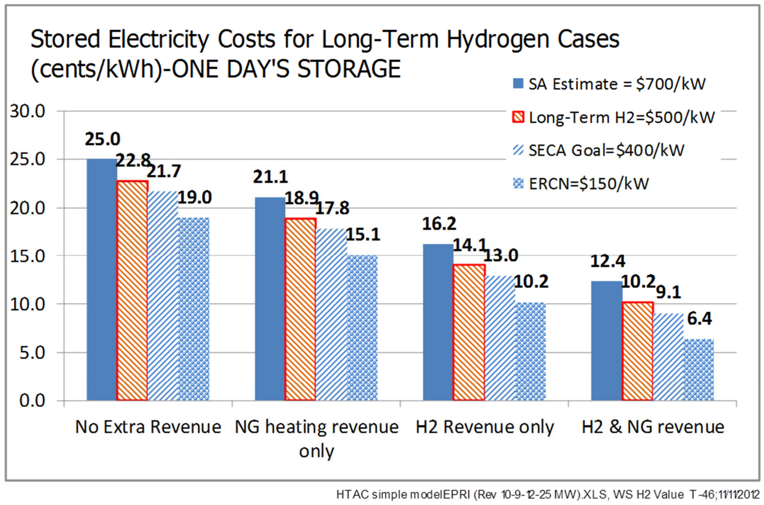


Figure 17. Required cost of on-peak electricity for one day's storage for CHHP systems to yield a 10% real, after-tax return on investment

Revenue from displaced heating fuel

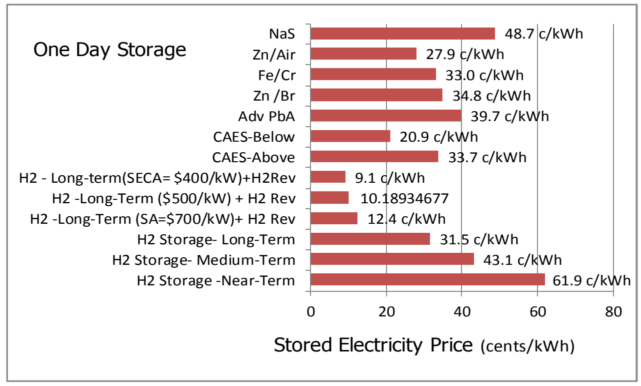
The storage system owner can also reduce costs of heating (or cooling) by using the waste heat from a SOFC to offset natural gas otherwise purchased to heat the facility. In the model we use the EIA's average projected cost of natural gas in 2015 at $6.29/MBTU[27]; we assume that the waste heat from the SOFC is equivalent to 30% of the HHV of the hydrogen input to the fuel cell, so the total efficiency of the SOFC is 85% (55% electrical efficiency plus 30% heat recovery).

The impact on required electricity peak prices of the hydrogen fuel and displaced natural gas revenue streams is summarized in Figure 17 for the four long-term hydrogen scenarios described above with one day's storage. Required electricity prices can be reduced by selling hydrogen fuel and displacing natural gas heating fuel as shown. For the $150/kW SOFC system, a stored electricity on-peak price of 6.4

[24] This assumes that the FCEV has 2.4 times higher efficiency than a gasoline ICV. -
[25] This value assumes that each FCEV travels 13,000 miles per year with a fuel economy of 68.3 miles/kg, and that - the FCEV owner refuels once every 8 days. -
[26] Initially, if there are too few FCEVs to consume this much hydrogen, it could be sold for other industrial uses, or - the hydrogen could be used for fuel cell fork lift trucks at warehouses and production plants. -
[27] The EIA estimates that residential NG will cost $10.56/Kscf; commercial NG at $8.82/Kscf; and Industrial NG at - $5/Kscf in 2015, and a weighted sales average of $6.60/Kscf. Assuming that NG has a heating value of 1.05 - MBTU/Kscf, this translates into a weighted average NG price of $6.29/MBTU. -

₵/kWh would be sufficient to pay for all operating expenses plus earning a 10% real, after-tax ROI on the original hydrogen storage system capital equipment. For the more probable SOFC costs ($400/kW to $700/kW), the on-peak required prices are still quite promising: 9.1 to 12.4 cents/kWh including both hydrogen fuel sales and the 30% heat recovery to offset natural gas.

The required stored electricity on-peak prices to earn the 10% real, after-tax ROI are shown in Figure 18 for one day's underground storage for the hydrogen and other storage systems. We have added the hydrogen sales revenue and heat recovery to the hydrogen storage long-term case which reduces the required electricity price from 31.5 ₵/kWh to 10.2 ₵/kWh, which is less than the price from a Zn/air storage system, the lowest future battery price at 27.9 ₵/kWh.

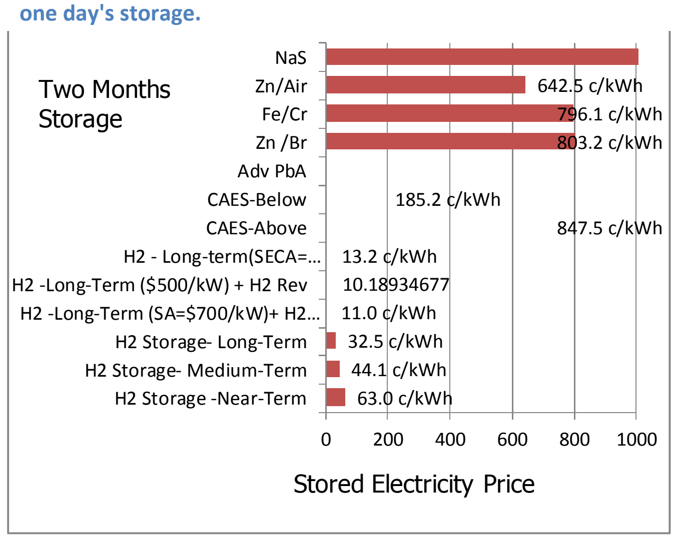


HTAC simple model EPRI (Rev 10-9-12-25MW).XLS, WS 'Dashboard' AW-323;3/19/2012

Figure 18. Required on-peak electricity prices for a 10% ROI for one day's storage.

The long-term SOFC systems reduce the required stored electricity prices even further, where we have assumed both hydrogen fuel revenue and displaced natural gas credits for waste heat recovery from these high-temperature fuel cell systems. The SOFC electricity cost estimates of 9.1 to 12.4₵/kWh are quite promising, especially since this electricity is from storage and can be sold at any time of day or year during peak demand.

The required electricity prices for 2-months storage are shown in Figure 19. With this longer-term storage, all hydrogen storage systems are lower cost than any of the battery or CAES options by large margins. Even the near-term hydrogen storage option is 3 times less expensive than the lowest cost alternative, below ground CAES.



HTAC simple model EPRI (Rev 10-9-12-25MW).XLS, WS 'Dashboard' BC-323;3/19/2012

Figure 19. Required electricity prices for two months' storage with the same conditions as Figure 18

Needless to say, 6-months seasonal storage of hydrogen has an even larger advantage over the competition. As shown in Figure 20, the long-term hydrogen price required is 34.5 ₵/kWh without hydrogen fuel revenue[21], which might be competitive for peak utility loads, and the price could be reduced to the range between 11 to 26 ₵/kWh for the SOFC systems with hydrogen fuel revenue and avoided natural gas credits. Figure 20 also includes the case for generating the electricity from stored hydrogen using a NG combustion turbine at a cost of $665kW, which yields a required on-peak electricity price of 17 ₵/kWh to make the target ROI.

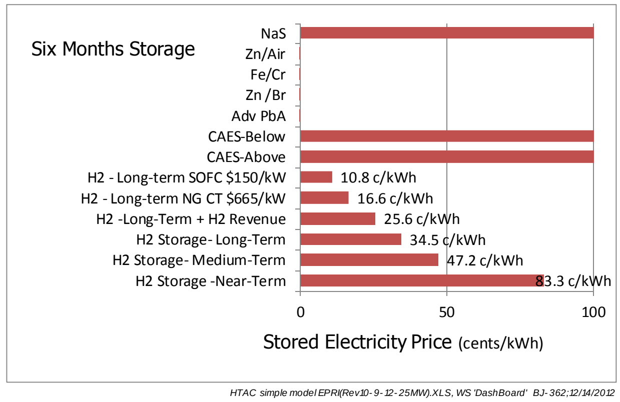


Figure 20. Required electricity prices for a 10% ROI with six months underground storage for hydrogen (all other options are "off the chart!")

Conclusions

Based on our models of energy storage, we come to the following conclusions:

1. - The cost of storing excessive or stranded renewable energy using hydrogen is less expensive than using even advanced battery storage systems such as the Zn/Air advanced battery suggested by EPRI.
2. - Long-term seasonal storage of wind energy is advantageous since winter peak wind energy is sometimes twice the summer wind energy.
3. - For longer-term storage, hydrogen is less expensive than compressed air energy storage (CAES) for storage times longer than 60 days in the near-term, longer than 30 days in the medium-term and longer than 14 days for the long-term hydrogen storage system projections.
4. - If a portion of the stored hydrogen is sold to fuel for fuel cell electric vehicles (FCEVs), and excess thermal energy from a high temperature stationary fuel cell were used to heat or cool buildings, then the stored hydrogen converted to electricity could be sold during peak electricity demand at prices between 9.1 and 12.4 cents/kWh and the project would still make a 10% real, after-tax return on the hydrogen system investment.
5. - With seasonal (6-month) energy storage all other storage options would require peak electricity rates in excess of $1/kWh to make the target 10% ROI.
6. **We conclude that hydrogen energy storage is the only cost effective method of long-term energy storage that could enable the widespread utilization of intermittent renewables such as wind energy.**

Acknowlegements

We would like to thank the members of the HTAC hydrogen enabling renewables working group for their many contributions to this work, including Bob Shaw, Charles Freese, Daryl Wilson, George Sverdrup, Harol Koyama, Jason Marcinkowski, Levi Thompson, Maurice Kaya, Monterey Gardner, Peter Bond, Rob Friedland and Todd Ramsden, with special thanks to Sandy Thomas who constructed the

computer model[28] used to provide the data reported in this document and also special thanks to Darlene Steward who developed the community hydrogen storage model and provided NREL data to calibrate the computer model used to generate the data in this report, and a special thanks to Frank Novachek as chairman of the working group for his leadership over several years of bi-weekly conference calls and periodic reports to the full HTAC committee.

<u>Recommendations for Future Work</u>.

While this initial work has demonstrated the value of hydrogen storage to enable greater grid penetration of intermittent renewables, we recommend several additional tasks:

- Determine if there are national policies that would significantly increase renewables penetration
- Conduct systems analyses including and excluding long-term storage using the policy scenarios identified above
- Estimate the value of hydrogen energy storage to the overall system
- Determine what value to assign the otherwise "spilled" renewables to make multi-day scale hydrogen (and other) energy storage economical
- <u>Community Energy Storage/Transportation System</u>: conduct sensitivity analyses to determine what conditions are necessary for a hydrogen system to compete with electric battery system for fueling FCEVs and EVs, respectively, with solar PV energy.
- <u>Model and analyze the economics of "power-to-gas" systems</u> that feed renewable hydrogen into the existing natural gas distribution network, including utilizing that hydrogen for its heating value in current natural gas appliance's, and also analyzing the economics of extracting the hydrogen from the pipeline as fuel for FCEVs.

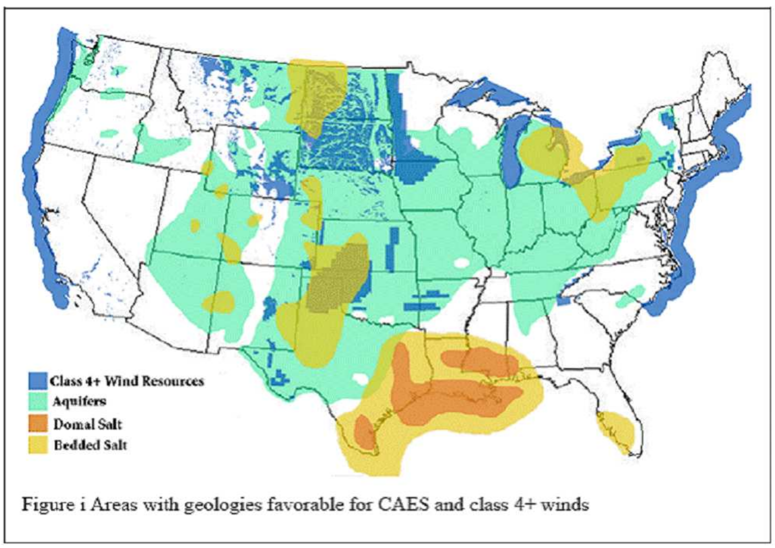


Figure 21.Underground storage potential in the US[29].

- Determine the efficacy of storing hydrogen in underground aquifers and depleted natural gas fields[29],[30]. One source[31] warns that hydrogen can interact with microorganisms and with

[28] Bob Shaw provided the initial guidance and direction for the basic architecture of this computer model.
[29] Some analysts have implied that hydrogen can only be stored in capped salt formations, which would limit underground storage to the Gulf region in the US. For example, according to one source[29] (Figure 21), California does not have any underground aquifers or domed salt caverns.

minerals that can reduce storage volume by plugging micro-porous spaces in the depleted field or aquifer.

[30] Source: P. Sullivan, W. short, & N. Blair, NREL, June 2008 "Modeling the Benefits of storage technologies to wind Power." See NREL site for wind storage: http://search.nrel.gov/query.html?qp=site%3Awww.nrel.gov+site%3Asam.nrel.gov&style=nrel&qs=&qc=nrel&ws=0&qm=0&st=1&nh=10&lk=1&rf=0&oq=&col=nrel&qt=wind+energy+storage&x=0&y=0

[31] A. Ozarslan, "Large-scale hydrogen energy storage in salt caverns," *International Journal of Hydrogen Energy*, Vol. 37, Issue 19, Pgs. 14265-14277, October 2012.

Appendix 2

Community Energy: Analysis of Hydrogen Distributed Energy Systems with Photovoltaics for Load Leveling and Vehicle Refueling

Darlene Steward

Community Energy: Analysis of Hydrogen Distributed Energy Systems with Photovoltaics for Load Leveling and Vehicle Refueling

Review Draft November 2013

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Executive Summary

Hydrogen energy storage could complement photovoltaic (PV) electricity generation at the community level. Because PV generation is intermittent, strategies must be implemented to integrate it into the electricity system. Hydrogen and fuel cell technologies offer possible PV integration strategies, including two community-level approaches analyzed in this report: 1) using hydrogen production, storage, and reconversion to electricity to level PV generation and grid loads; and 2) using hydrogen production and storage to capture peak PV generation and refuel hydrogen-powered vehicles.

These approaches are applied to a community of 100 residences, approximated by the electricity demand of a small hotel in Boulder, Colorado. To assess the impact of increasing PV market penetration, three levels of PV power generation spanning a broad range in comparison to the community's electricity demand were studied. The simulated community is served by a PV system sized at 1,200 m^2 (producing electricity equivalent to 50% of annual building electricity load), 4,000 m^2 (~170%), or 7,000 m^2 (~290%).

In the load-leveling system, electricity from the PV panels satisfies building demand directly, and excess PV electricity produces hydrogen via an electrolyzer. A fuel cell converts the hydrogen back into electricity to serve the building demand when PV output is inadequate, and grid electricity satisfies any demand that cannot be met directly by the PV system or stored hydrogen. Seasonal variation in the PV system output has a marked effect on the sizing of the storage systems for the three PV system sizes. For the 1,200-square-meter (m^2) PV system, the PV electrical output exceeds the building load during certain times of the day, but the total daily output never exceeds the total daily load. Therefore, for the 1,200-m^2 system, the storage system cycles daily and electricity is never sold back to the grid. In contrast, for the 4,000- and 7,000-m^2 systems, the daily PV output often exceeds the daily load, so multi-day storage is needed. For the 4,000-m^2 system, 780 kilograms (kg) (~14,600 kilowatt-hours [kWh])—equivalent to approximately 9 days of storage—accommodates the seasonal variation in PV output and no electricity is sold back to the grid. For the 7,000-m^2 system, it is not feasible to fully account for seasonal variation in PV output with storage. Therefore, the storage system for the 7,000-m^2 system was sized to include approximately 4 days of storage, and a considerable amount of electricity is sold to the grid during periods when the storage system is full.

The vehicle-refueling system is similar to the load-leveling system, except that vehicles use the excess energy instead of buildings, and no electricity is sold back to the grid. The amount of electricity produced in excess of the building load determines the number of vehicles—either hydrogen fuel cell vehicles or plug-in electric vehicles—that could be fueled in each case. The vehicle-refueling methods include electrolytic hydrogen production for hydrogen-powered vehicles and battery storage for plug-in electric vehicles. In the case of vehicle refueling, the storage systems are sized to meet the minimum needed for a complete fill (in the case of the 1,200-m^2 PV system) or one day of excess PV output plus 50 percent. It is assumed that vehicle fuel demand that cannot be met by the community refueling system during the winter and stretches of cloudy weather will be accommodated by nearby stations.

The vehicle-refueling cost analysis is performed for two cases: Case 1, in which all PV electricity output in excess of the building load is used for vehicle refueling, and Case 2, in which all PV electricity output before noon is used for vehicle refueling in addition to all PV output in excess of the building load.

Table ES-1 shows the levelized cost of electricity (LCOE) from the storage system for each load-leveling scenario. The systems are sized for load leveling under the constraint of a limited grid/transformer size but are not fully optimized for cost. The results show a relatively complex relationship between PV system size and the economics of power generation from each system. The leftmost set of results shows the LCOE of the PV-generated electricity that is routed directly to the building plus electricity that is produced from the storage system. Costs tend to increase as the delta between the PV system output and the building load increases because the storage system must be larger. However, this upward trend in cost is balanced by better utilization of the storage equipment (electrolyzer, hydrogen tanks, and fuel cell) for the larger systems. So, the LCOE is lowest for the small PV system and highest for the mid-range system. The trend in storage system utilization is illustrated by the rightmost set of results, which shows the LCOE for only the stored portion of the electricity. In this set of results, the LCOE steadily decreases with increasing PV system size. In all cases, the electricity produced by either the battery or hydrogen storage system is more expensive than grid electricity. Therefore, the storage system must provide benefits in addition to cost, such as relieving grid congestion and/or providing backup power, to be cost effective.

Table ES-1. Load-Leveling System Costs with and without PV Costs Included

Scenario	Total Direct Capital Cost Including PV System ($000)	Levelized Cost of All Electricity (Direct Supply to Building + Stored Electricity) (¢/kWh) (% of output to storage)[b]	Total Direct Capital Cost without PV System ($000)	Levelized Cost of Stored Electricity (¢/kWh)[b]
1,200-m^2 PV/storage system	$727	33 (32%)	$271	109
4,000-m^2 PV/storage system	$2,958	57 (70%)	$1,438	62
7,000-m^2 PV/storage system[a]	$3,393	45 (38%)	$733	36

[a]The 7,000-m^2 PV system produces close to 3 times the building load. Therefore, nearly the entire building load can be supplied with the PV system direct output plus stored electricity. After supplying the building load, a large fraction of the PV system output (44%) is sold to the grid at the cost of producing it.
[b] Levelized costs include all direct and indirect costs for the apportioned cost of the PV system, hydrogen/battery production, storage and delivery, and replacement and operating expenses over the life of the system.

The vehicle-refueling analysis shows the potential for community-level hydrogen refueling using only renewably generated electricity (Table ES-2). With the 4,000-m^2 PV system, the number of fuel cell vehicles served (70–80) roughly matches the modeled community size (100 households). The levelized hydrogen cost ranges from $34/kg ($1.01/kWh) for the 1,200-m^2 Case 1 system to $11/kg ($0.34/kWh) for the 7,000 m^2 Case 2 system. The cost of battery storage of electricity for electric vehicles ranges from $0.57/kWh–$0.39/kWh, also decreasing with increasing system size. The levelized cost of hydrogen is high for even the most favorable case in comparison to expected early commercial station hydrogen costs. However, the system produces 100% renewable hydrogen and provides potentially valuable load leveling of distributed PV output, allowing for grid integration of much larger PV systems. The hydrogen system cost reduction for the larger systems is due, as for the load leveling system, to better utilization of the equipment. The hydrogen system configuration is also more flexible than the battery system because there are more independent pieces of equipment. For small systems, this is a disadvantage, but for larger systems the increased flexibility reduces costs because an incremental increase in hydrogen storage capacity per kWh (hydrogen tank) is less expensive than an incremental (per kWh) increase in electrochemical storage. Even though the hydrogen system is lower cost than the battery system for the largest storage case, the electric vehicle is less expensive on a fuel ¢/mile basis because of its higher efficiency in comparison to the fuel cell vehicle.

For both the load leveling and vehicle fueling scenarios, the system cost is highly dependent on component costs and system configuration. In all scenarios, the load-leveling or refueling system reduces peaks and valleys in grid demand and energy fed onto the grid. The vehicle refueling scenarios provide as much smoothing of the PV system output/grid demand as the load-leveling scenarios. Storage and/or diversion of excess electricity from distributed generation systems that can smooth seasonal and daily variations in PV system output may be advantageous for very high levels of PV penetration.

Table ES-2. Summary of Vehicle Refueling Cost Results

Hydrogen for Fuel Cell Vehicles[a]								
	Case 1 (Excess Electricity)				Case 2 (Excess Electricity + Morning Output)			
PV Size (m^2)	Production (kg H_2/yr)	Vehicles Served	H_2 LCOE ($/kg)	H_2 Cost (¢/mi)	Production (kg H_2/yr)	Vehicles Served	H_2 LCOE ($/kg)	H_2 Cost (¢/mi)
1,200	1,804	9	34	56	3,541	17	22	38
4,000	14,564	72	13	22	16,985	84	12	21
7,000	29,274	146	12	20	31,898	159	11	19
Electricity for Battery-Electric Vehicles[a]								
	Case 1 (Excess Electricity)				Case 2 (Excess Electricity + Morning Output)			
PV Size (m^2)	Production (kWh/yr)	Vehicles Served	Elec. LCOE ($/kWh)	Elec. Cost (¢/mi)	Production (kWh/yr)	Vehicles Served	Elec. LCOE ($/kWh)	Elec. Cost (¢/mi)
1,200	61,726	17	0.57	17	121,936	35	0.45	13
4,000	500,755	143	0.41	12	585,475	168	0.40	12
7,000	1,008,212	289	0.39	11	1,100,877	316	0.39	11

[a] Levelized costs include all direct and indirect costs for the apportioned cost of the PV system, hydrogen/battery production, storage and delivery, and replacement and operating expenses over the life of the system. For the 4,000- and 7,000-m^2 PV systems, the hydrogen capital costs are lower than the battery-electric capital costs; however, the higher efficiency of the battery-electric vehicle system (29 kWh/100 miles for electric vehicles versus 55.6 kWh/100 miles for fuel cell electric vehicles [DOE FuelEconomy.gov website, accessed June 20, 2013: http://www.fueleconomy.gov]) still results in a lower per-mile cost for the battery-electric vehicle system.

Table of Contents

List of Figures

List of Tables

1 Introduction

Higher penetrations of distributed renewable energy systems, specifically residential rooftop photovoltaic (PV) systems, could affect loading and capacity margins for community-level electricity distribution systems. PV output typically peaks slightly before the peak daily electricity demand. This offset could cause overloading of local distribution equipment at high PV penetration levels. The addition of plug-in electric vehicles, which would primarily be charged at residences, might also affect loading of distribution systems. Several researchers have analyzed the effect of electric and plug-in hybrid electric vehicles on the grid (Denholm et al. 2013; Srivastava et al. 2010). Denholm et al. analyzed options for integrating PV and electric vehicle charging, finding benefits of mid-day vehicle charging for reduction of petroleum use and potentially enabling smaller vehicle batteries. While Denholm et al.'s analysis focused on mid-day charging at commercial places of business, this analysis addresses the unique challenges of integrating large penetrations of PV at the residential level where grid capacity constraints may be most acute.

Hydrogen (H_2) energy storage could complement PV electricity generation at the community level. Because PV generation is intermittent, strategies must be implemented to integrate it into the electricity system. Hydrogen and fuel cell technologies offer possible PV integration strategies, including two community-level approaches discussed in this paper: 1) using hydrogen production, storage, and reconversion to electricity to level PV generation and grid loads; and 2) using hydrogen production and storage to capture peak PV generation and fuel hydrogen-powered vehicles.

Energy storage is one potential strategy for addressing load variations due to high residential PV penetration. This brief study analyzes the costs and benefits of installing hydrogen-based energy storage for community-level PV system load leveling. It examines the effects of increasing PV penetration in residential neighborhoods on the use of grid electricity and the opportunity for hydrogen energy storage.

Peak PV output could also be diverted for use directly in electric vehicles or, after conversion to hydrogen, in hydrogen-powered fuel cell vehicles. In this analysis, the electricity or hydrogen is temporarily stored in batteries or hydrogen tanks so that vehicles can be refueled when the residents return home in the evening.

The target scenario for the study is approximately 100 single-family, detached houses served by a single pad-mounted transformer at the end of a grid distribution line. As PV penetration increases for these houses, what are the opportunities and economics for energy storage using hydrogen? How does that compare to diverting the excess electricity to fueling of vehicles? A modified version of the U.S. Department of Energy's Fuel Cell Power Model (FCPower 2012) was used to perform this analysis.

The next section describes the building profile and PV systems followed by the load-leveling and vehicle-refueling systems. Section 3 shows cost analysis results for the load-leveling and vehicle-refueling systems, Section 4 offers conclusions, and Section 5 includes suggestions for future work.

2 System Descriptions and Energy Flows

The following subsections detail the characteristics of the building profile used in both the load-leveling and vehicle-refueling scenarios; the electrolyzer, fuel cell, and PV systems used in the scenarios; and the load-leveling and vehicle refueling systems themselves.

2.1 Building Profile and PV Systems

The same building profile was used for the load-leveling and vehicle-refueling scenarios. The hourly load profile for a small hotel in Boulder, Colorado was used as a surrogate for a community of 100 residences (Field et al. 2010; National Renewable Energy Laboratory [NREL] 2009). The hotel load profile is expected to be similar to the load profile for a residence because of similar use patterns; most people get up and ready for work in the morning and then return later in the afternoon. This use pattern results in a peak in electricity demand between 6:00 a.m. and 10:00 a.m. and another between 5:00 p.m. and 10:00 p.m. Because the hotel load, with an average demand of about 65 kW, is larger than would be expected for 10–15 single family residences (with an average demand of 1–2 kW per household), the analysis was scaled up in size. However, the equipment costs are scaled linearly, and the energy flow relationships are the same as for a smaller system. Some characteristics of the hotel building load profile are listed in Table 1. Figure 1 plots the electricity demand for the hotel during a typical day in July.

Table 1. Key Characteristics of the Boulder Hotel Building Load Profile

Building Load Statistics	
Demand maximum (kW)	125.3
Demand minimum (kW)	28.4
Demand average (kW)	65.4
Demand std dev (kW)	22.8
Demand total (kWh/year)	572,518

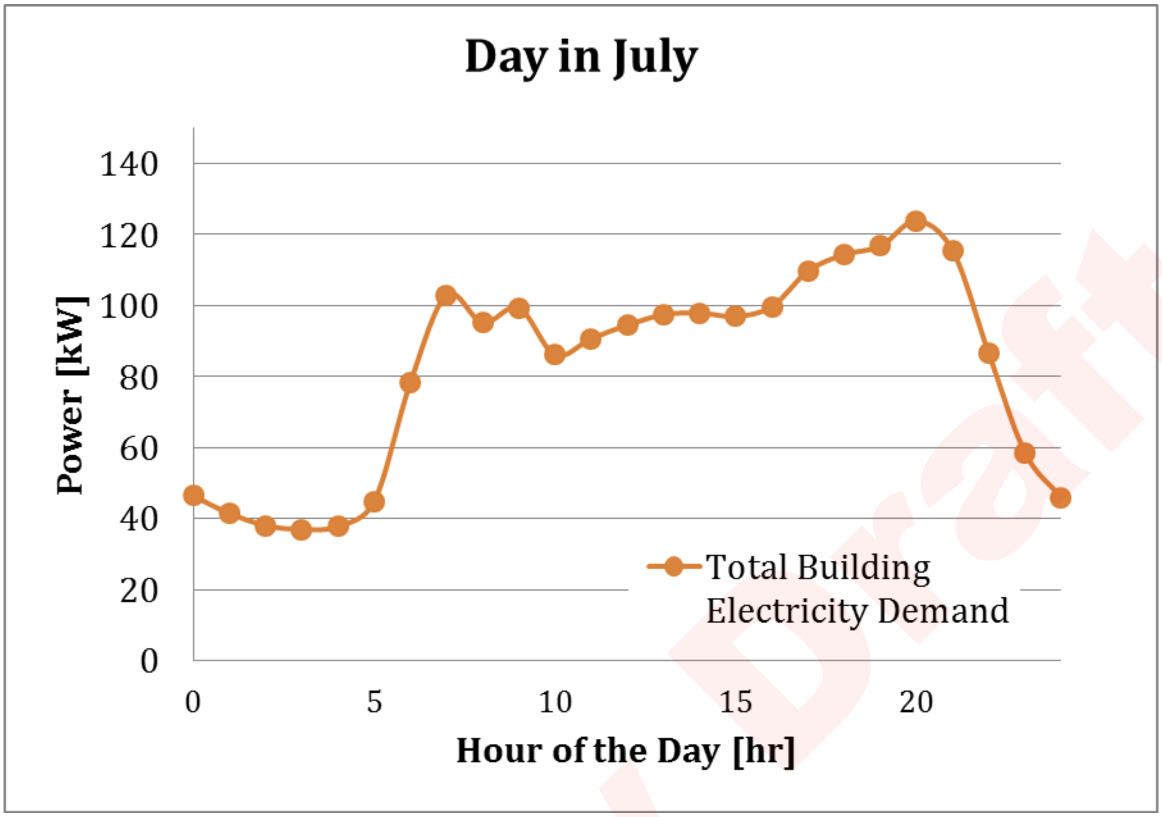

Figure 1. Building electricity demand profile, selected day in July

The same PV systems were used for the load-leveling and vehicle-refueling scenarios (Table 2). The three PV systems range in size from about half the yearly building load to almost three times the building load. The capacity factor for the PV systems is 18%.[1] NREL's hourly solar resource data for Boulder, Colorado (NREL 2009) was imported into the FCPower model for use in the simulations.

Table 2. Key PV System Performance Parameters

PV System Size (m^2)	Peak Rated Output (kW)	Yearly Output (kWh)	Approximate Percent of Building Load
1,200	183	286,704	50%
4,000	611	955,681	170%
7,000	1,069	1,672,442	290%

2.2 Load-Leveling System

Figure 2 shows a schematic representation of the equipment and building layout for the load-leveling system. Electricity from the PV panels is first used to satisfy the building demand (100 houses approximated by the hotel profile described previously) directly. If the output from the

[1] The capacity factor is calculated as the actual PV output (kWh) divided by the potential output if the PV panels were producing at their maximum power for 24 hours a day.

PV system is higher than the building demand at that time, the electricity is routed to the electrolyzer where it is used to produce hydrogen for storage. During periods when the demand is high but PV output is low, for example in the evening, the stored hydrogen is used in the fuel cell to produce electricity for the building demand. Any additional building demand is met using electricity from the grid. On rare occasions, the storage system may be full and excess electricity from the PV system is routed to the transformer and fed onto the grid. In this scenario, the fuel cell output is only used to satisfy the building demand and is never routed to the grid.

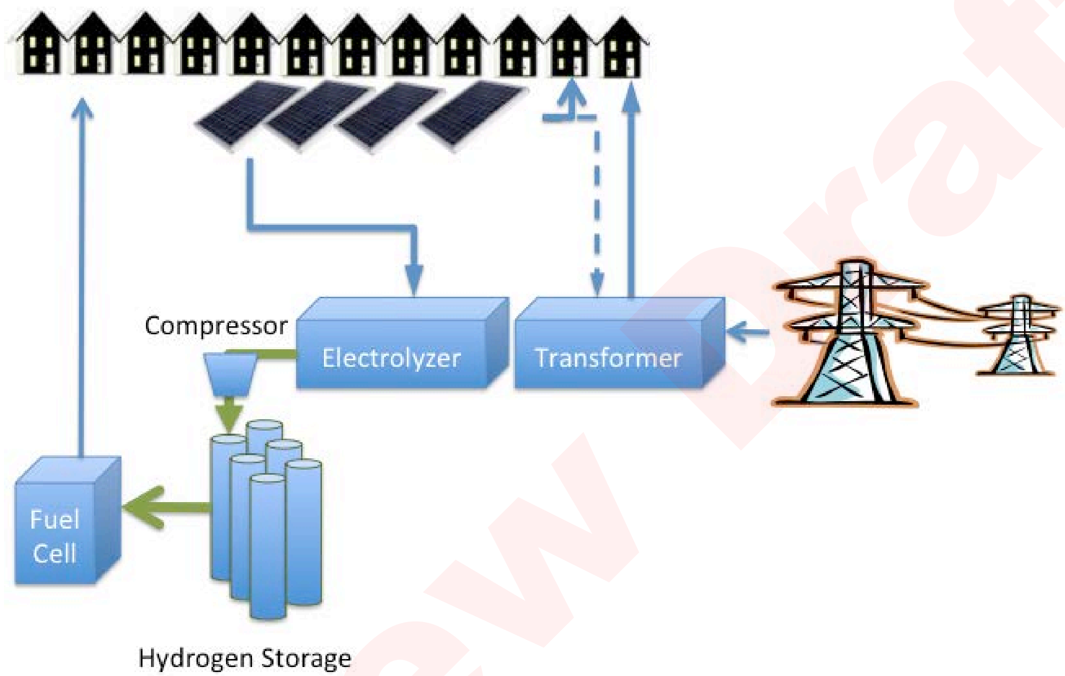

Figure 2. Schematic diagram of equipment and energy flows for the load-leveling system

Seasonal variation in the PV system output has a marked effect on the sizing of the storage systems for the three PV system sizes. Seasonal fluctuations in PV output/H_2 produced by the electrolysis system can be accommodated for the 1,200- and 4,000-m^2 systems. However, sizing the hydrogen production and storage system to accommodate seasonal variations in hydrogen production for the 7,000-m^2 PV system is not practical. Therefore, for the 7,000-m^2 system, both the electrolyzer and hydrogen storage system are scaled down and more electricity is routed to the grid.

For the 1,200-m^2 PV system, the PV electrical output exceeds the building load during certain times of the day, but the total daily output never exceeds the total daily load. Therefore, for the 1,200-m^2 system, the storage system cycles daily and electricity is never sold back to the grid. In contrast, for the 4,000- and 7,000-m^2 systems, the daily PV output often exceeds the daily load, so multi-day storage is needed. For the 4,000-m^2 system, 780 kg (~14,600 kWh), which is equivalent to approximately 9 days of storage, accommodates the seasonal variation in PV output, and no electricity is sold back to the grid. For the 7,000-m^2 system, it is not feasible to fully account for seasonal variation in PV output with storage. Therefore, the storage system for the 7,000-m^2 system was sized to approximately 4 days of storage, and a considerable amount of electricity is sold to the grid during periods when the storage system is full.

Table 3 shows the efficiencies of the electrolyzer, fuel cell, and compressor modeled in the system.

Table 3. Efficiencies of the Load-Leveling System's Electrolyzer, Fuel Cell, and Compressor

Model Parameter	Units	Value
Electrolyzer efficiency	%HHV	78%–87%[a]
Fuel cell efficiency	%LHV	53%–58%[b]
Compressor system efficiency	%HHV	92%

[a] 66%–74% lower heating value (LHV). Electrolyzer efficiency decreases with increasing hydrogen output. The electrolyzers for the 1,200- and 4,000-m^2 systems operate, on average, at about 40% of their rated power. The electrolyzer for the 7,000-m^2 system operates at about 84% of its rated power.
[b] Fuel cell efficiency decreases with increasing electricity output. For the three systems, the fuel cell capacity factor ranges from 89% (1,200-m^2 system) to 45% (7,000-m^2 system).
HHV = higher heating value

Figure 3 shows the energy flows for this system (with 1,200 m^2 of PV) during a day in October. On this day, there is sufficient PV generation to carry the load without using the grid and produce hydrogen for storage (purple "X"s) from about 10:00 a.m. to 5:00 p.m. Sufficient hydrogen is stored during the day to carry part of the load in the evening; however, no hydrogen remains to produce electricity during the early morning hours. As Figure 4 shows, for the scenario with 1,200 m^2 of PV, there is a wide variation in the amount of hydrogen produced during various times of the year. During periods of high demand (e.g., the day in July) or low solar output (e.g., the day in January), very little hydrogen is produced.

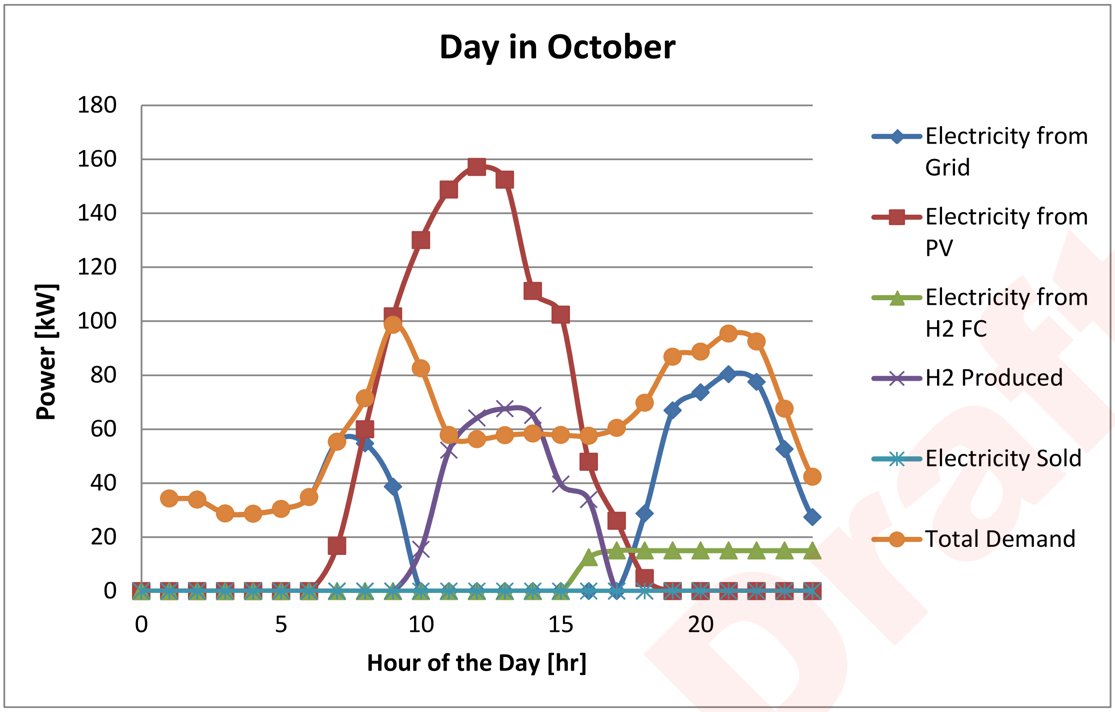

Figure 3. Boulder hotel electricity demand, PV generation, and storage system energy flows for a typical day in October (1,200 m^2 PV)

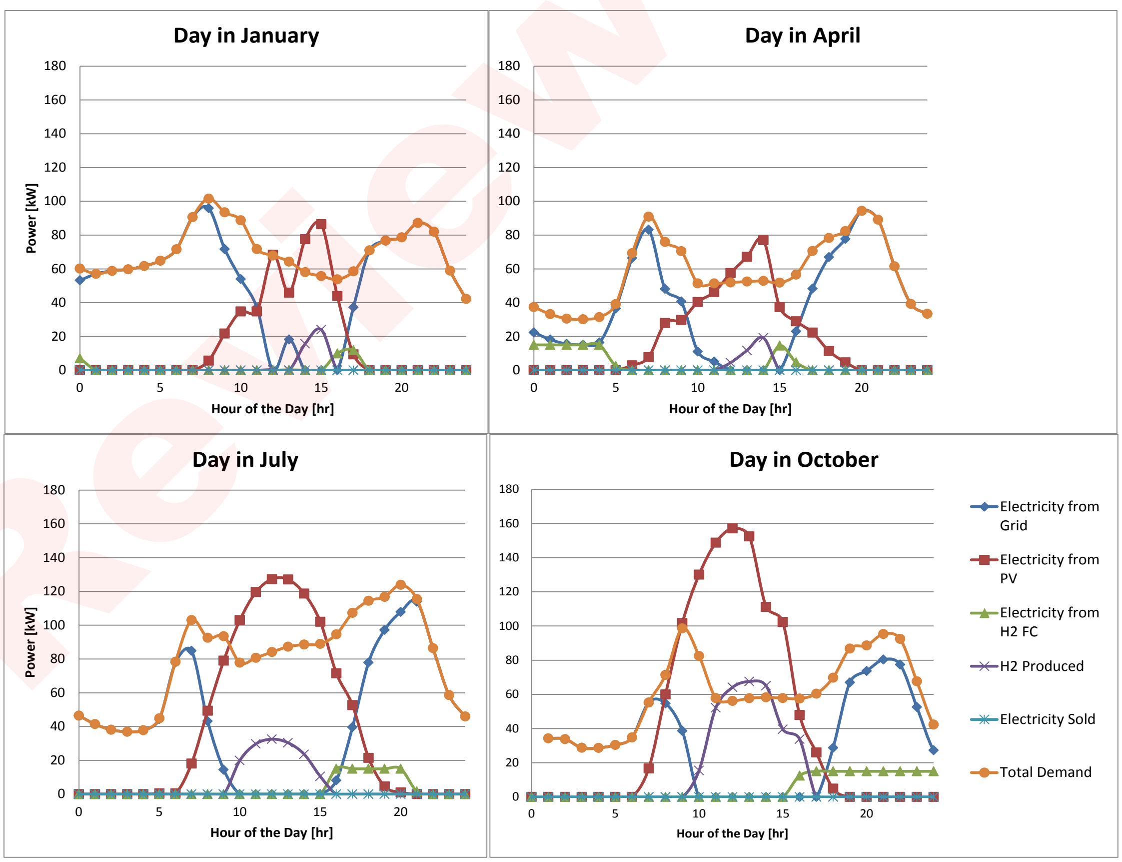

Figure 4. Seasonal variation with 1,200 m^2 of PV, four selected days

With 1,200 m^2 of PV installed, there is insufficient hydrogen production/storage to completely offset morning and evening peak power draws from the grid, especially during the summer when demand is higher. However, peak draws from the grid are reduced 10%–15% in the afternoon and evening peak period for part of the year. The peak output from the PV system is usually between 120 and 160 kW, which typically occurs when the building load is around the average of 65 kW. Without the storage system, the transformer occasionally would need to accommodate the difference in output of up to 100 kW of electricity being fed onto the grid. The storage system completely eliminates this energy flow. Table 4 summarizes the energy flows for the 1,200 m^2 PV/energy storage system. Figure 5 and Figure 6 show energy flows on various days for the 4,000- and 7,000-m^2 PV systems.

Table 4. Summary of Energy Flows for 1,200-m^2 PV/Energy Storage System

Equipment/System	System Size	Yearly Output	Capacity Factor (% of Max Output during Operation, [h/yr])	Percent of Building Load (Building + Compressor)
PV system	1,200 m^2 (~ 183 kW peak rated output)	286,704 kWh	18	50 (total) 34 (direct supply)
Electrolyzer	127 kW input	1,833 kg	38 [1,904]	—
Hydrogen storage	16 kg	~ 1 cycle per day	—	—
Hydrogen fuel cell	15 kW output	32,094 kWh	89 [2,402]	6
Grid	—	348,771 kWh	—	61
Electricity sold	—	0 kWh	—	—

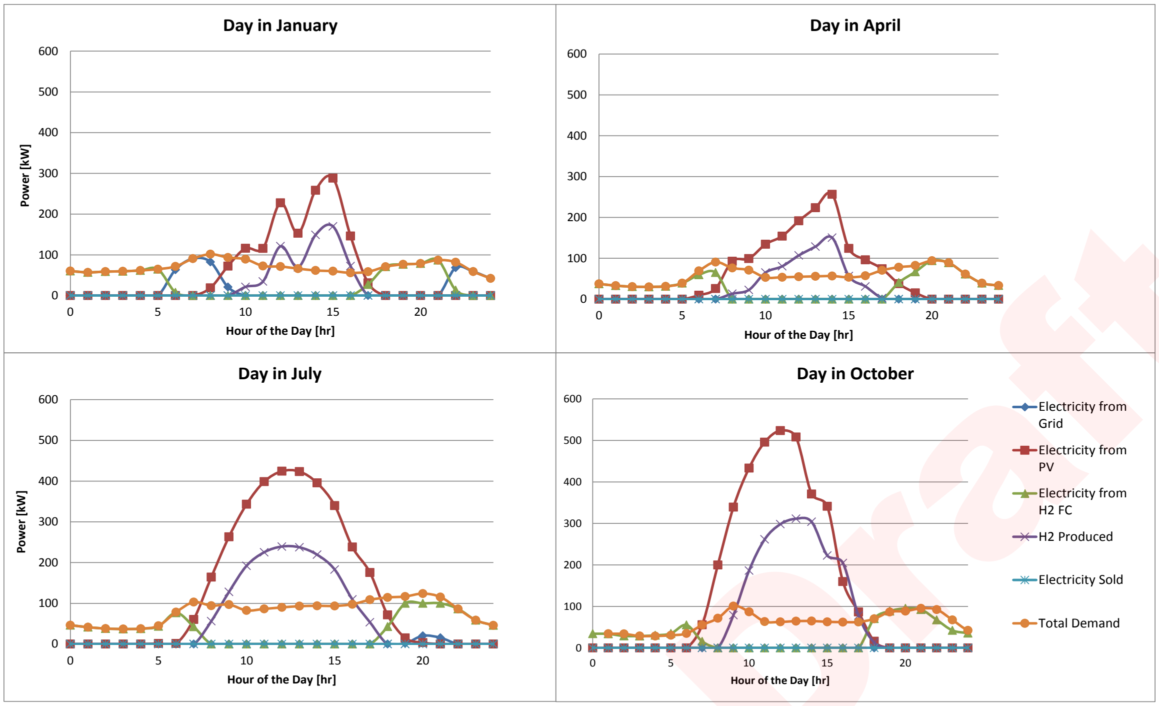

Figure 5. Seasonal variation with 4,000 m^2 of PV

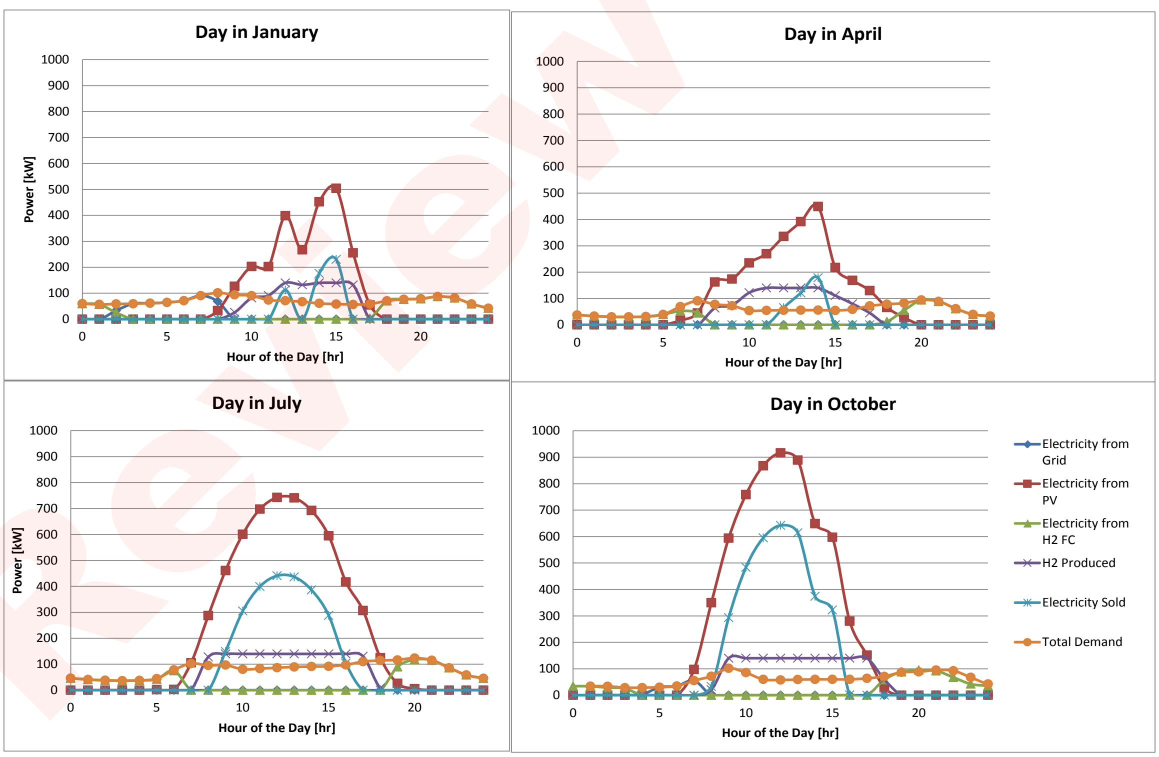

Figure 6. Seasonal variation with 7,000 m^2 of PV

Table 5 summarizes the energy flows for the 4,000-m^2 system. The total yearly PV output is 167% of the building yearly load. However, only about 48% of the PV output occurs at times when it can directly supply the building load. For this configuration, there is insufficient hydrogen production/storage to offset morning and evening peak power draws from the grid completely, especially during the summer when demand is higher. However, peak draws from the grid are reduced 50%–75% in the afternoon and evening peak period for most of the year.

Table 5. Summary of Energy Flows for 4,000-m^2 PV System

Equipment/System	System Size	Yearly Output	Capacity Factor (% of Max Output during Operation, [h/yr])	Percent of Building Load (Building + Compressor)
PV system	4,000 m^2 (~ 611 kW peak rated output)	955,681 kWh	18	167 (total) 48 (direct supply)
Electrolyzer	578 kW input	14,797 kg	39 [3,265]	—
Hydrogen storage	780 kg	Variable days of storage depending on the season	—	—
Hydrogen fuel cell	100 kW output	277,770 kWh	55 [5,065]	47
Grid	—	25,995 kWh	—	4
Electricity sold	—	0 kWh	—	—

Table 6 summarizes the energy flows for the 7,000-m^2 system. The total yearly PV output is 292% of the building yearly load. However, only about 51% of the building load can be supplied by the PV system directly. In this scenario, there is sufficient hydrogen production and storage capacity to supply 42% of the building load using the hydrogen fuel cell. The hydrogen fuel cell for the 7,000-m^2 system supplies less of the building load than the fuel cell for the 4,000-m^2 system because storage for the 7,000-m^2 system is smaller than for the 4,000-m^2 system and thus provides less seasonal storage than for the 4,000-m^2 system. The peak output from the PV system is about 1,069 kW, which typically occurs when the building load is 60–100 kW. Without the storage system, the transformer would need to accommodate the difference in output of close to 1,000 kW of electricity being fed onto the grid. The storage system reduces this energy flow by diverting some of the excess electricity to the electrolyzer. In the configuration analyzed, the electrolyzer reduces peak electricity flow to the grid by 220 kW, the input electricity capacity of the electrolyzer. For the 7,000-m^2 PV system scenario, not all peaks in energy flow to the grid are eliminated. In this scenario, there are several occasions when the energy flow to the grid exceeds 700 kW.

Table 6. Summary of Energy Flows for 7,000-m^2 PV System

Equipment/System	System Size	Yearly Output	Capacity Factor (% of Max Output during Operation, [h/yr])	Percent of Building Load (Building + Compressor)
PV system	7,000 m^2 (~ 1,069 kW peak rated output)	1,672,442 kWh	18	292 (total) 51 (direct supply)
Electrolyzer	221 kW input	12,757 kg	84 [3,619]	—
Hydrogen storage	325 kg	Variable days of storage depending on the season	—	—
Hydrogen fuel cell	125 kW output	246,321 kWh	45 [4,388]	42
Grid	—	38,405 kWh	—	7
Electricity sold	—	729,410 kWh	—	44% of PV output

2.3 Vehicle-Refueling System

The vehicle-refueling system is similar to the load-leveling system, except that vehicles absorb the excess energy instead of buildings, and no electricity is sold back to the grid. The vehicle refueling serves the purpose of load leveling, eliminating large electricity fluctuations and reverse power flow from the PV system through the transformer. The modeled community consists of about 100 houses (approximated with the hotel profile described previously) with corresponding vehicle-refueling demand. Electricity from the PV system supplies the building load; when PV output is less than the building load, the grid supplies the difference. The transformer and distribution lines have enough capacity to supply the peak building load. Figure 7 shows a schematic of the system.

The PV system also produces all fuel for the vehicles (i.e., the grid does not supply electricity for vehicle fuel). Two types of vehicle refueling systems are compared in this analysis. One uses electrolytic hydrogen production for hydrogen-powered vehicles (Figure 8), and the other uses battery storage for charging plug-in electric vehicles (Figure 9).

The vehicle-refueling cost analysis was performed for two cases:

- Case 1—All PV electricity output in excess of the building load is used for vehicle refueling.
- Case 2—All PV electricity output before noon is used for vehicle refueling in addition to all PV output in excess of the building load.

Figure 10 show schematics of the PV electricity output used for vehicle refueling in Case 1 and Case 2.

In the hydrogen vehicle-refueling analysis, an electrolyzer is sized to accommodate the maximum electricity production used to generate hydrogen.[2] The compressor is sized to the peak hourly hydrogen flow rate. The storage system is assumed to cycle fully each day (i.e., there is no multi-day storage). The amount of hydrogen storage needed was calculated by running the model with very large daily hydrogen demand to ensure that the analysis simulates daily cycling of the storage system. The storage volume needed was then set at the maximum amount of hydrogen in storage at any time during the year (for the very high demand case) plus 50% or a minimum value for a full tank refueling based on the assumed cascade system volume of 65 kg. This results in about 75 kg of storage for the smallest system (1,200-m^2 PV Case 1), which produces only an average of approximately 5 kg/day. A relatively large excess storage was assumed for the larger systems to account for the large daily fluctuations in PV output and the fact that actual hydrogen refueling is likely to be less uniform than modeled. The analysis does not assume that the additional storage accounts for seasonal variations in hydrogen/electricity demand or production. Month-to-month variations in production are not large; the average monthly hydrogen production for the 4,000-m^2 system is ~1,200 kg/month with a standard deviation of ~140 kg/month. However, the high and low production months (March and December, respectively) only roughly correspond to expected high and low demand months (June–August and November–January, respectively) so in reality, it might be necessary to refuel vehicles offsite occasionally during part of the summer. There is also a predictable dip in PV output during the hottest part of the summer, when fuel demand is expected to peak. Although the analysis did not explicitly address seasonal variations in production or demand, it is likely that the additional storage modeled would be sufficient to accommodate them.

One 350-bar hydrogen dispenser with two hoses is used for daily hydrogen production ranging from only about 5 kg/day for the 1,200-m^2 Case 1 system to about 90 kg/day for the 7,000-m^2 Case 2 system. It is expected that hydrogen fuel cell vehicles used primarily for commuting would be refueled about once per week. Although most vehicle manufacturers are planning for 700-bar refueling, 350-bar dispensing is assumed for this analysis. Vehicles designed for the higher pressure are capable of being refueled at lower pressure (although the tank cannot be completely filled), and 700-bar dispensers are considerably more complex and expensive than 350-bar dispensers. The additional expense was not felt to be justified for the low throughput of hydrogen and community-based refueling envisioned in this study.

The alternative vehicle-refueling system uses electricity to charge a zinc-air storage battery system consisting of one or more batteries that may be located together or distributed through the community. The batteries are used to store energy for a brief period (less than 1 day) so that battery-electric vehicles can be charged in the evening and overnight. The battery system is sized to accommodate the maximum difference between the PV daily output (kWh) and the building load plus 50% in order to have enough capacity to charge several vehicles (for the smaller system cases) and to more closely match the hydrogen systems. The battery system is assumed to discharge fully each day (i.e., there is no multi-day storage), and each vehicle is refueled with a home-based Level 1 (120V) charging unit (comparable to a 350-bar hydrogen system). The zinc-

[2] In this analysis, the maximum electricity production used to generate hydrogen is calculated for two cases: In Case 1, it is the difference between the PV output and the building load, and in Case 2 it is the amount in Case 1 plus all PV electricity generated before noon.

air battery/vehicle charging system is assumed to have an overall electrical efficiency of 73%.[3] The purpose of modeling this battery-electric system is to provide a reasonable contrast with the hydrogen-fuel cell system rather than to model a real-world battery-electric system in detail.

The hydrogen and electric vehicles are assumed to have identical charging profiles every day of the year, and all vehicles are refueled between 4:00 p.m. and 9:00 p.m. Although this is a more realistic profile for hydrogen refueling than for electric vehicle nighttime charging, the differences in profiles do not affect the analysis because neither type of vehicle would be refueled at a time when a significant amount of PV electricity could be used directly for vehicle fueling. In all cases, the amount of fuel produced is determined by how much of the PV output can be directed to the battery or electrolyzer. Therefore, the same amount of electricity is used for vehicle refueling whether the vehicles are powered by hydrogen or electricity; the battery-electric system simply powers more vehicles because of its higher efficiency.[4] Figure 11 shows the vehicular hydrogen/electricity demand profile along with the building electricity demand profile. Figure 12 shows all the system energy flows. Table 7 and Table 8 show the energy flows for Cases 1 and 2.

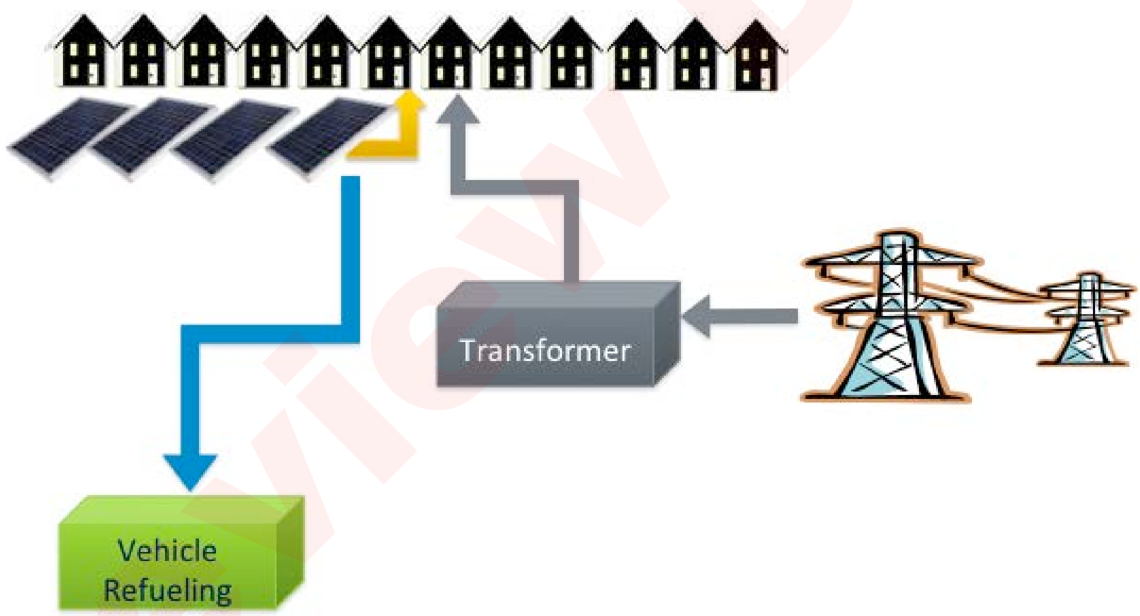

Figure 7. Schematic diagram of equipment and energy flows for the vehicle-refueling system. There is no energy flow from the vehicle-refueling system to the building.

[3] Zinc-air battery round trip efficiency was assumed to be slightly less than the value reported by Rastler (2010) to account for losses in home charging of vehicles.
[4] The all-electric vehicles are based on the Nissan Leaf with a 100-mile all-electric range and driven 12,000 miles per year.

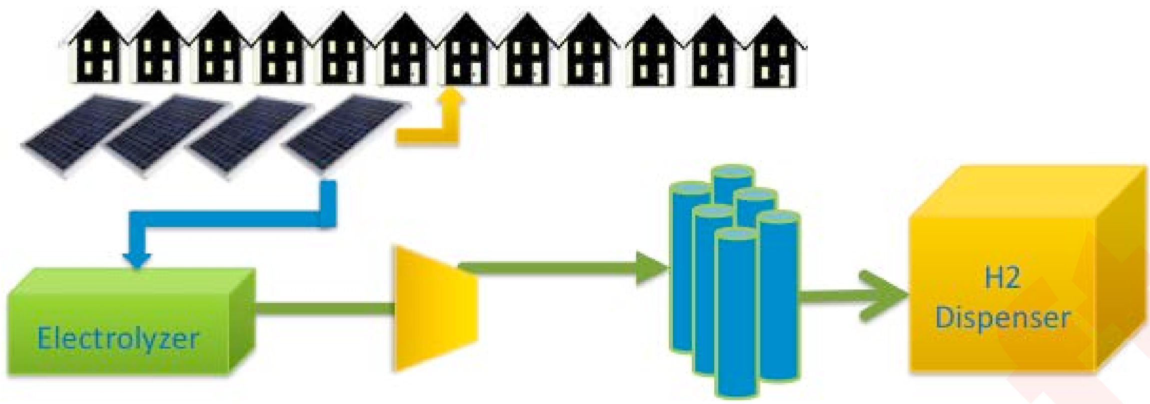

Figure 8. Detail of hydrogen vehicle-refueling configuration. There is no energy flow from the vehicle-refueling system to the building.

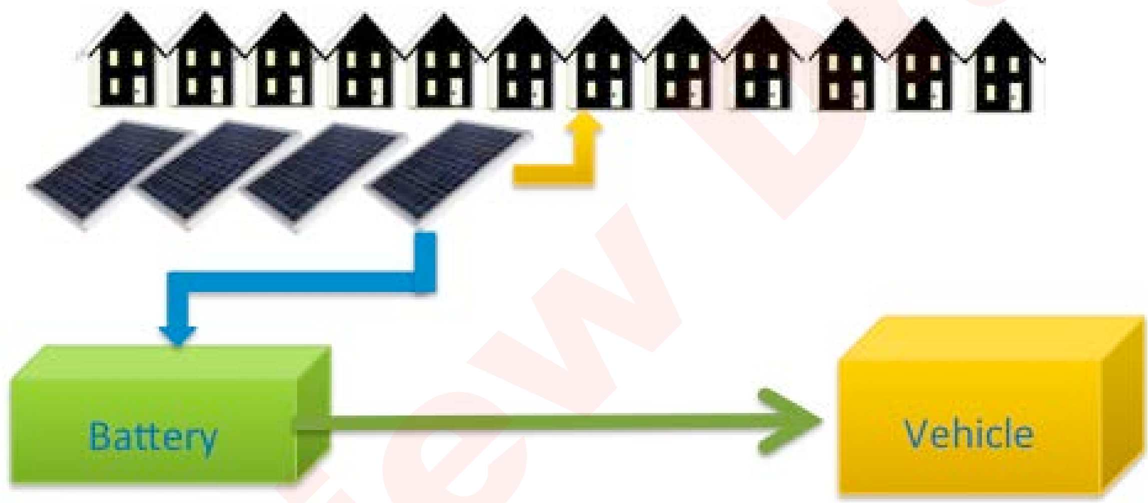

Figure 9. Detail of alternative (battery) vehicle-refueling configuration. There is no energy flow from the vehicle-refueling system to the building.

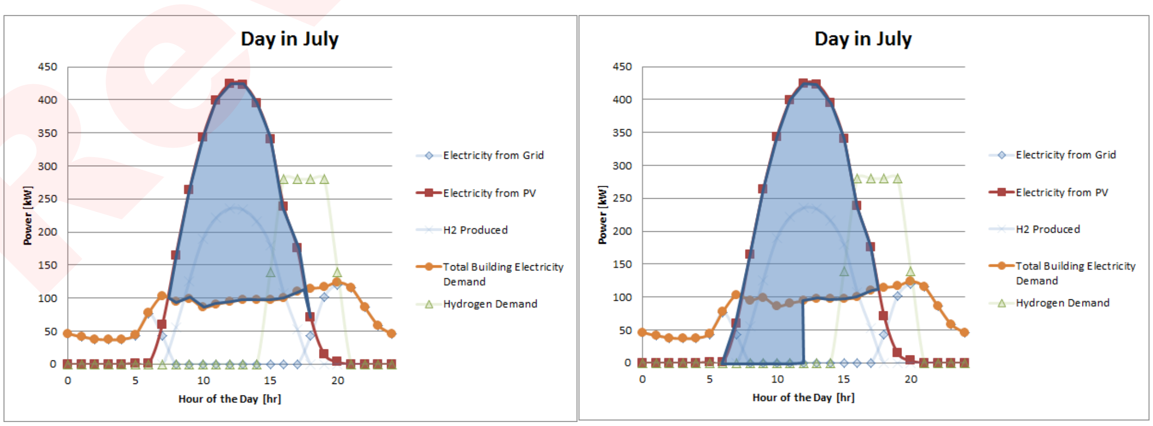

Figure 10. PV electricity output used for vehicle refueling in Case 1 (left) and Case 2 (right)

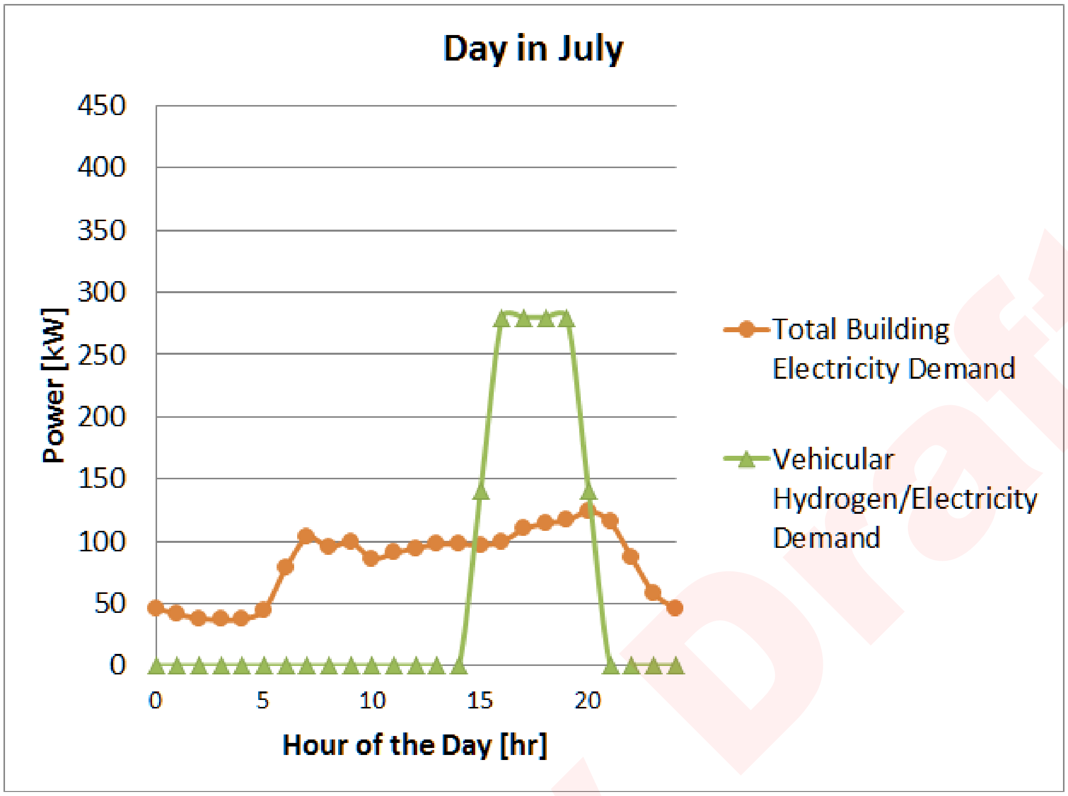

Figure 11. Example vehicular hydrogen/electricity demand profile (4,000-m^2 PV system)

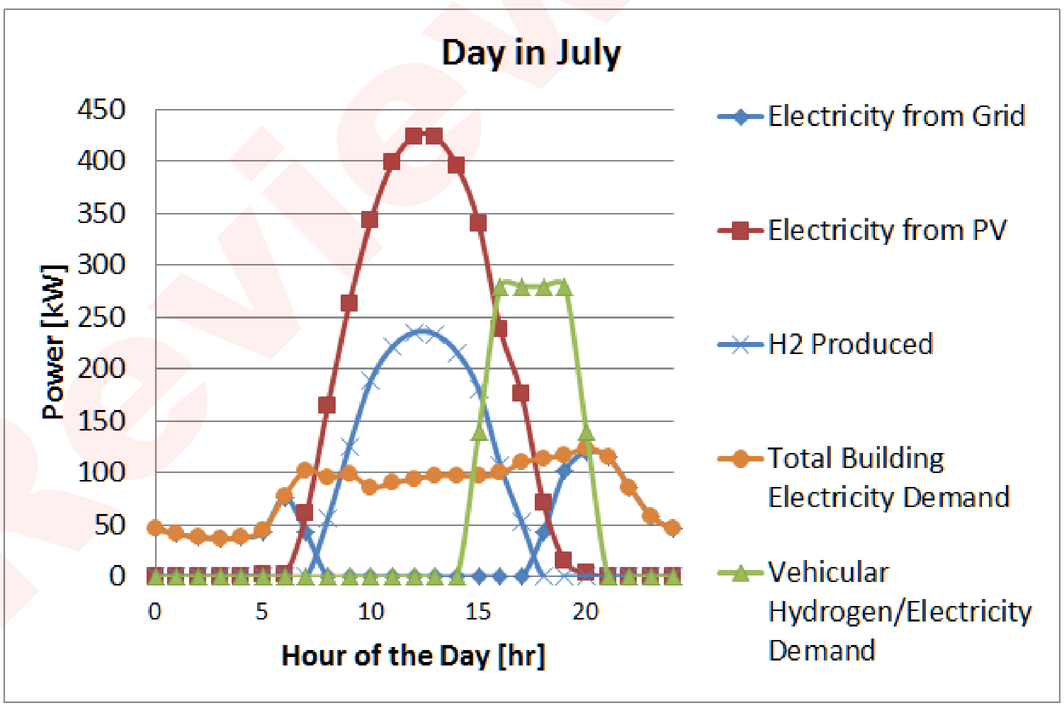

Figure 12. Building electricity demand, vehicular hydrogen/electricity demand, PV and grid electricity supply, and hydrogen produced (or electricity to storage) during a typical day in July (4,000-m^2 PV system)—Hydrogen Case 1

Table 7. Summary of Energy Flows for Vehicle-Refueling System (Hydrogen and Battery/Electric Systems)—Case 1

Equipment/System	System Size	Yearly Output	Capacity Factor (% of Max Output during Operation, [h/yr])	Percent of Building Load
1,200-m^2 PV System				
PV system	1,200 m^2 (~ 183 kW peak rated output)	286,704 kWh	18	50 (total) 35 (direct supply)
Electrolyzer (H_2 system)	127 kW input	1,804 kg	36 [1,904]	—
Hydrogen storage (H_2 system)	75 kg	~ 1 cycle per day	—	—
Vehicle electricity (battery system)	—	61,726 kWh	—	—
Battery storage (battery system)	589 kWh	~ 1 cycle per day	—	—
Grid	—	370,486 kWh	—	65
4,000-m^2 PV System				
PV system	4,000 m^2 (~ 611 kW peak rated output)	955,681 kWh	18	167 (total) 47 (direct supply)
Electrolyzer (H_2 system)	560 kW input	14,564 kg	40 [3,265]	—
Hydrogen storage (H_2 system)	85 kg	~ 1 cycle per day	—	—
Vehicle electricity (battery system)	—	500,755 kWh	—	—
Battery storage (battery system)	2,954 kWh	~ 1 cycle per day	—	—
Grid	—	303,744 kWh	—	53
7,000-m^2 PV System				
PV system	7,000 m^2 (~ 1,069 kW peak rated output)	1,672,442 kWh	18	292 (total) 51 (direct supply)
Electrolyzer (H_2 system)	1,013 kW input	29,274 kg	39 [3,669]	—
Hydrogen storage (H_2 system)	165 kg	~ 1 cycle per day	—	—
Vehicle electricity (battery system)	—	1,008,212 kWh	—	—
Battery storage (battery system)	5,530 kWh	~ 1 cycle per day	—	—
Grid	—	283,082 kWh	—	49

Table 8. Summary of Energy Flows for Vehicle-Refueling System (Hydrogen and Battery/Electric Systems)—Case 2

Equipment/System	System Size	Yearly Output	Capacity Factor (% of max output during operation, [hrs/year])	Percent of Building Load
1,200-m^2 PV System				
PV system	1,200 m^2 (~ 183 kW peak rated output)	286,704 kWh	18	50 (total) 21 (direct supply)
Electrolyzer (H_2 system)	105 kW input	3,541 kg	36 [3,137]	—
Hydrogen storage (H_2 system)	90 kg	~ 1 cycle per day	—	—
Vehicle electricity (battery system)	—	121,936 kWh	—	—
Battery storage (battery system)	2,493 kWh	~ 1 cycle per day	—	—
Grid	—	453,078 kWh	—	79
4,000-m^2 PV System				
PV system	4,000 m^2 (~ 611 kW peak rated output)	955,681 kWh	18	167 (total) 27 (direct supply)
Electrolyzer (H_2 system)	554 kW input	16,985 kg	38 [3,907]	—
Hydrogen storage (H_2 system)	95 kg	~ 1 cycle per day	—	—
Vehicle electricity (battery system)	—	585,475 kWh	—	—
Battery storage (battery system)	3,305 kWh	~ 1 cycle per day	—	—
Grid	—	419,957 kWh	—	73
7,000-m^2 PV System				
PV system	7,000 m^2 (~ 1,069 kW peak rated output)	1,672,442 kWh	18	292 (total) 28 (direct supply)
Electrolyzer (H_2 system)	1,013 kW input	31,898 kg	38 [4,110]	—
Hydrogen storage (H_2 system)	165 kg	~ 1 cycle per day	—	—
Vehicle electricity (battery system)	—	1,095,214 kWh	—	—
Battery storage (battery system)	5,914 kWh	~ 1 cycle per day	—	—
Grid	—	410,195 kWh	—	72

2.4 Comparison of Load Leveling and Vehicle-Refueling Systems

The general strategy employed for the load-leveling cases was to minimize and smooth the electricity demand that must be met by the grid. In the vehicle refueling cases, the strategy focused on producing vehicle fuel (either hydrogen or electricity) exclusively from the renewable resource in the most cost-effective manner. Figure 13 illustrates the effect of each strategy on the amount of grid electricity purchased monthly for the 4,000-m^2 case. Note that some grid electricity is purchased almost every month for the storage scenario case, especially during the winter, even though the solar panels produce almost double the building load overall and produce nearly 50% more electricity than the building load during the winter. This occurs because the storage system, which is large enough to accommodate seasonal variations in PV system output (see Figure 14) for the energy storage scenario, gradually empties in the fall as PV daily electricity production decreases. During the winter, only electricity produced that day is available for electricity generation from the hydrogen fuel cell in the evening and overnight. On a cloudy day when little electricity is generated by the PV panels, there is no "cushion" of hydrogen in storage, and electricity must be purchased. For the two hydrogen vehicle cases, the electricity used to generate hydrogen is permanently removed from electrical system for the building and grid. There is no electricity generation from the storage system. The grid electricity needed to satisfy the building load is reduced because some electricity from the PV system can be directly routed to the building. Less grid electricity is required for hydrogen vehicle Case 1 (purple line in Figure 13) than for hydrogen vehicle Case 2 (green line in Figure 13) because the electricity from the solar panels is routed to the building for a longer period each day in Case 1. In all cases, the grid demand is reduced and smoothed as compared to the building demand alone.

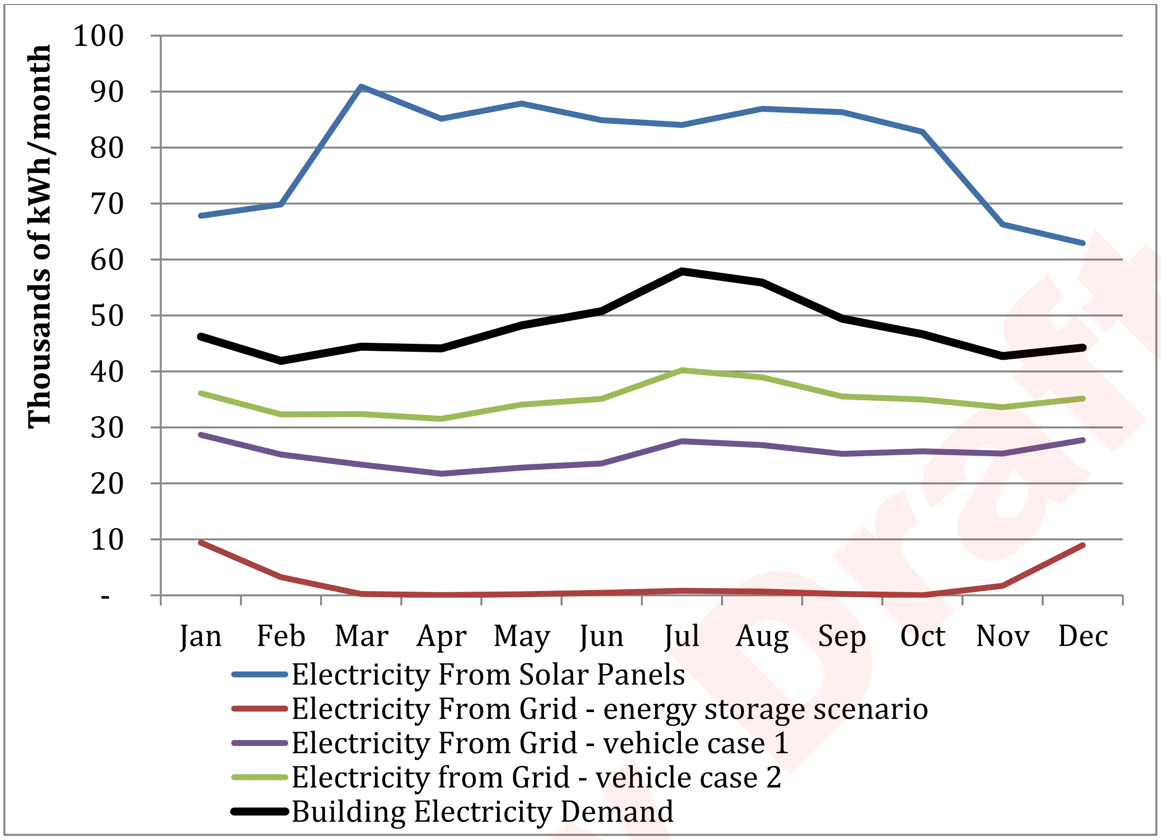

Figure 13. Monthly PV system output and electricity from the grid—4,000-m² PV system

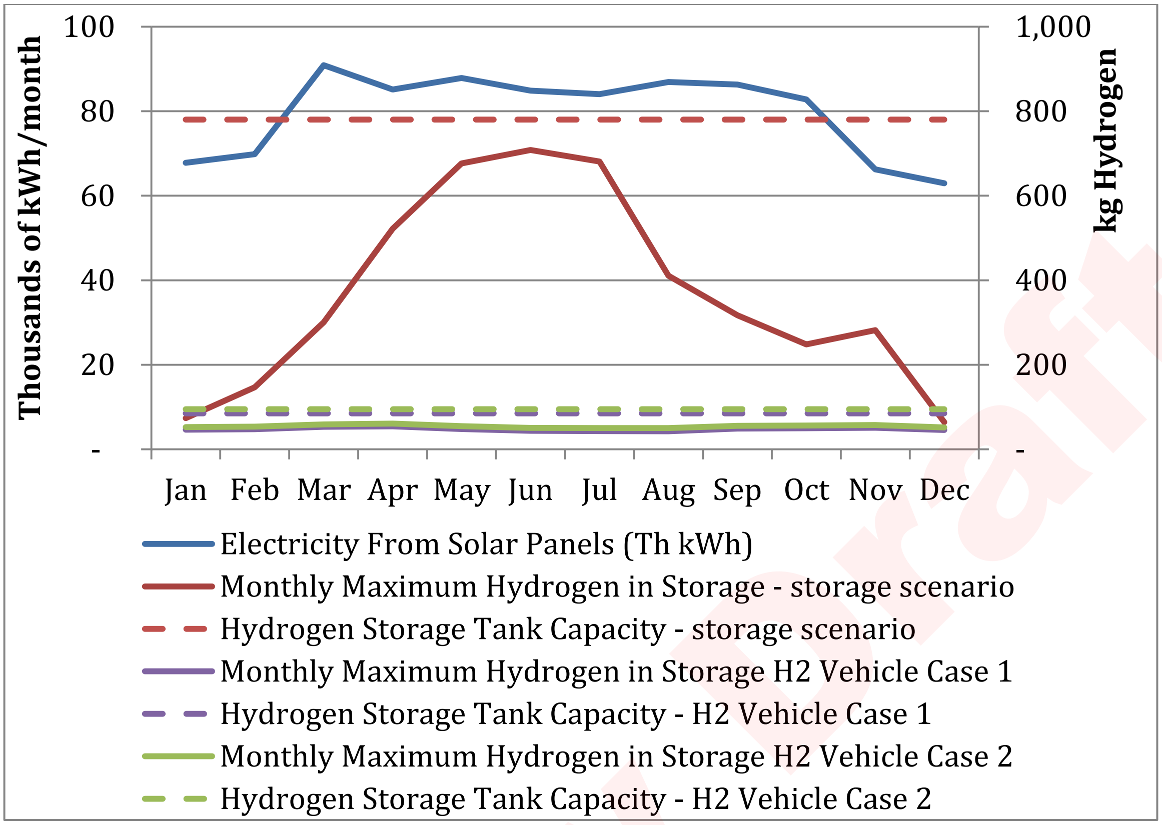

Figure 14. Monthly maximum hydrogen in storage for various scenarios—4,000-m^2 PV system

The smoothing effect of energy storage and diversion of excess PV production to vehicles is illustrated in Figure 15, which plots the maximum daily fluctuations in PV output and grid interactions for the 4,000-m^2 PV system case. Electricity that would have been routed to the grid in the absence of a storage or vehicle refueling system is shown in orange. With no storage or vehicle refueling system, the maximum delta within a single day between drawing electricity from the grid and routing electricity to the grid is 633 kW. With storage, the maximum is 103 kW, and with either of the hydrogen vehicle refueling systems, the maximum is 131 kW.

Monthly PV output and electricity from the grid for the 7,000-m^2 case is shown in Figure 16. Monthly maximum hydrogen in storage is shown in Figure 17.

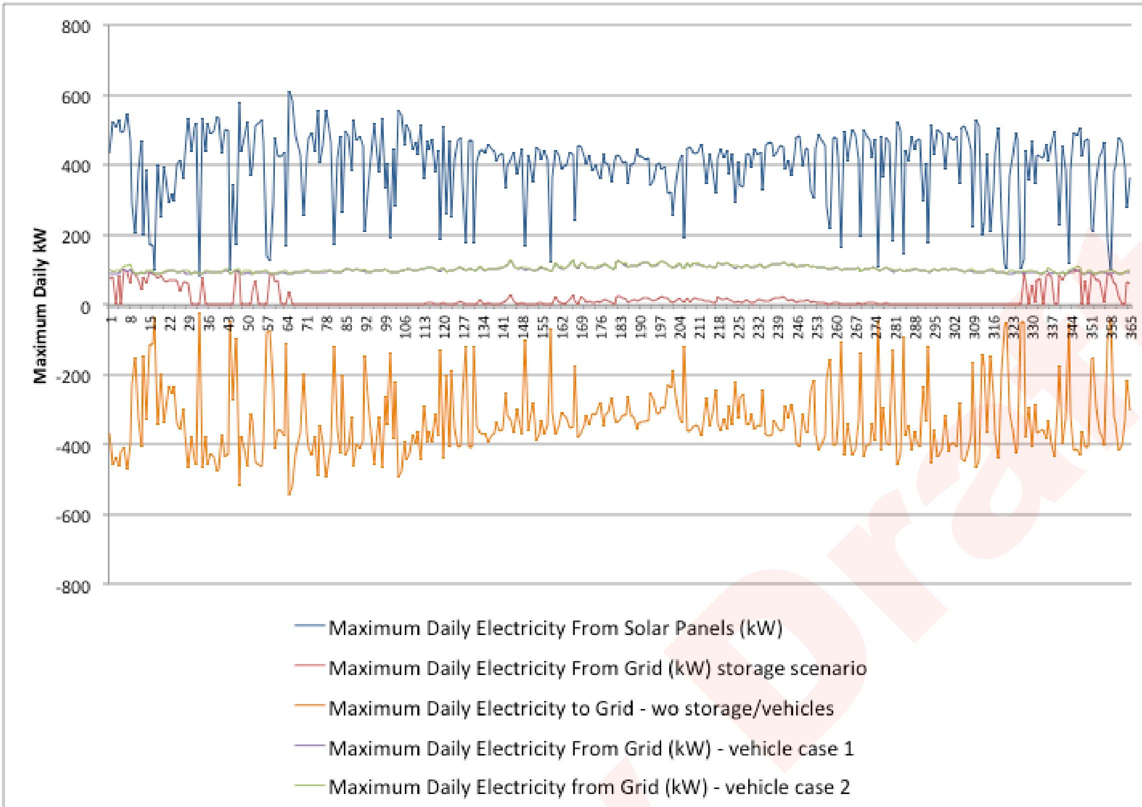

Figure 15. Maximum daily fluctuations in PV system output and grid interactions—4,000-m^2 PV system

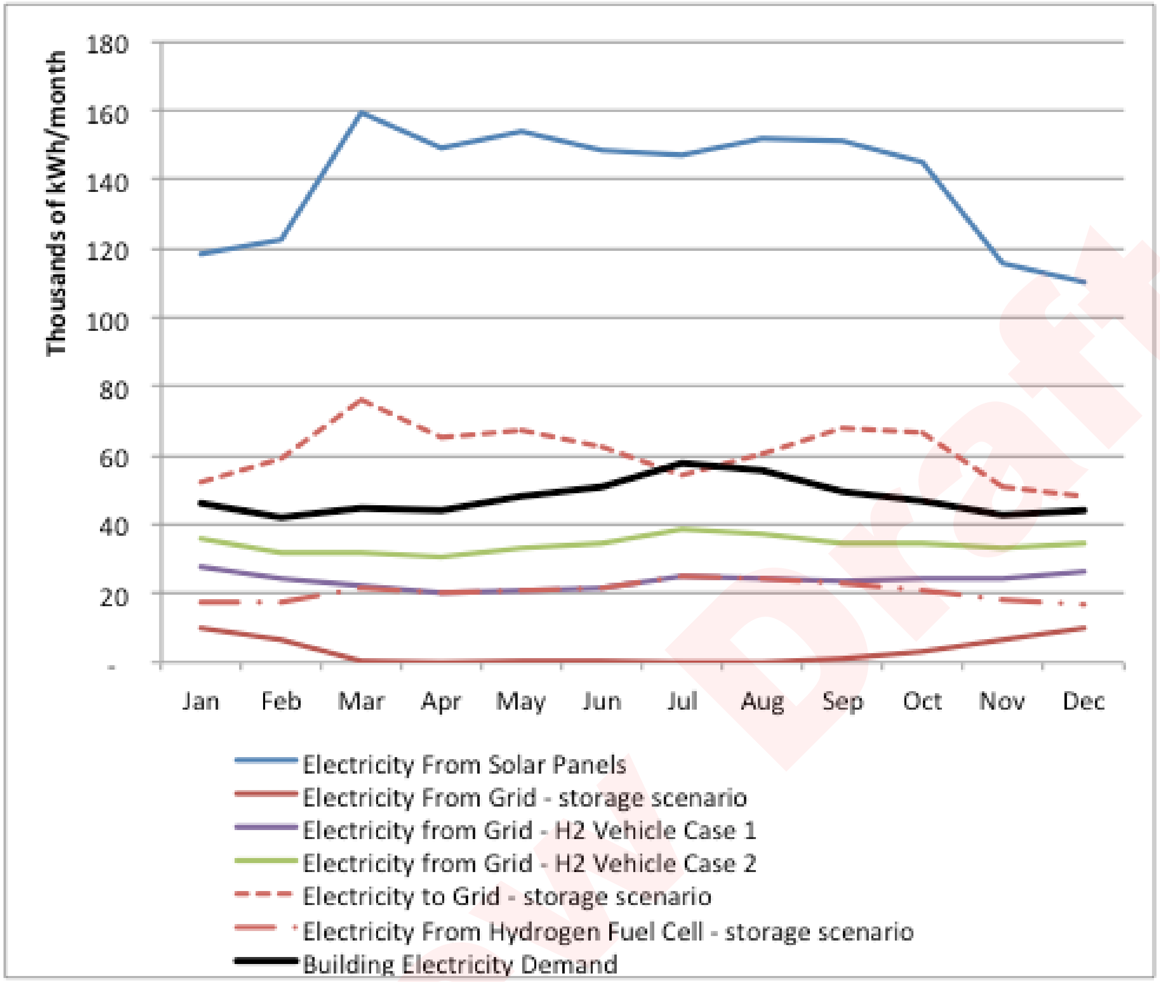

Figure 16. Monthly PV system output and electricity from the grid—7,000-m^2 PV system

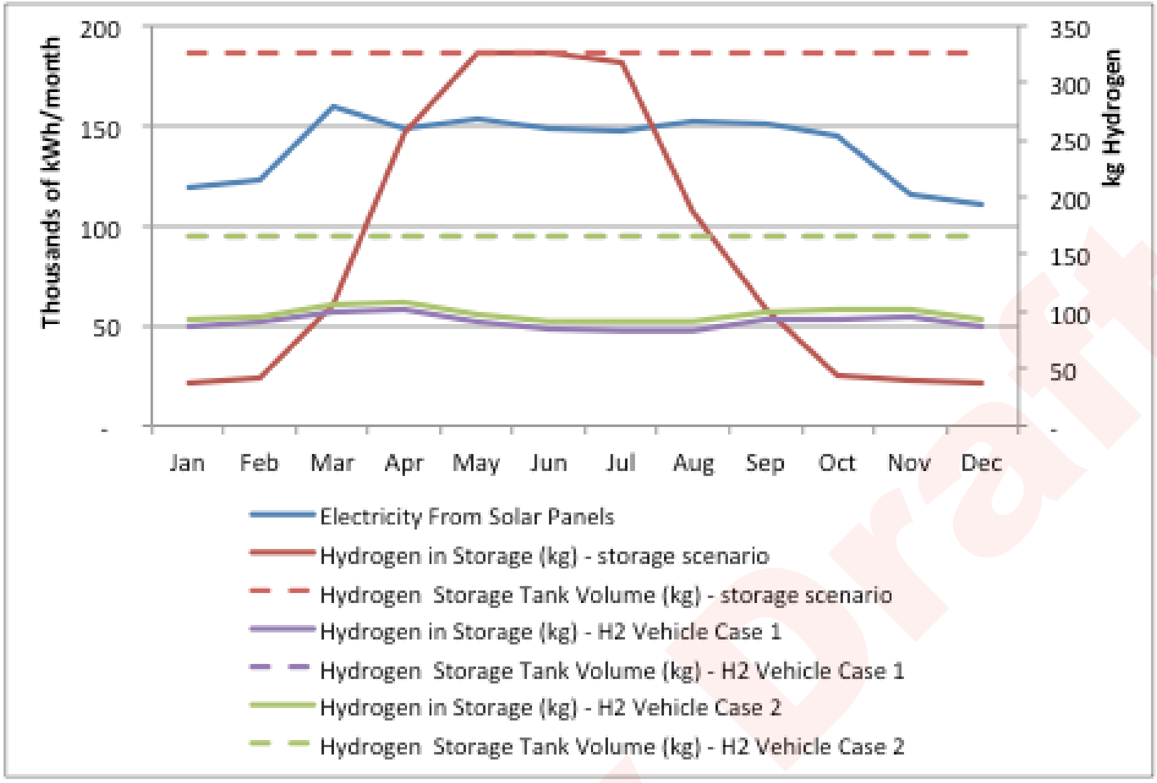

Figure 17. Monthly PV system output and electricity from the grid—7,000-m^2 PV system

3 Cost Analysis Results

A modified version of the NREL Fuel Cell Power (FCPower [2012]) spreadsheet model was used as the basis for the economic analyses for the community energy storage scenarios. The FCPower model incorporates the lifecycle discounted cash flow methodology developed for the H2A hydrogen production model (H2A Production Model 2012). A detailed explanation of the economic methodology is provided in an NREL technical manual for the economic evaluation of energy efficiency and renewable energy projects (Short et al. 1995). Cash flows, including revenues, variable and fixed operating expenses (fuel, labor, interest on debt, taxes, etc.), capital expenditures, and repayment of principal, are aggregated yearly over the lifetime of the project. This methodology captures the time dependence of costs and revenues over the life of the project. For example, the methodology accurately captures costs associated with replacement of equipment components at specific times in the future. All per kWh or per kg costs presented are levelized costs, including all direct and indirect costs and operating expenses over the life of the system.

An initial analysis of the PV system alone (without a storage system) was performed to establish a baseline cost for the PV-generated electricity. Because the PV system capital costs are assumed to be the same on a $/watt basis for all three system sizes, the levelized cost of electricity (LCOE) of electricity generated over the 30-year assumed life of the system is the same: 15¢/kWh for all of the systems. This value was used as the "selling price" for electricity routed directly to the building. In this way, the cost of the solar system was apportioned between the building and the storage/vehicle fuel production system. The apportioned cost of the solar system is included in the LCOE results of the storage or fuel production cases unless specifically stated otherwise.

Table 9 lists the equipment and associated costs for the community energy storage scenarios. All equipment costs are assumed to scale linearly within the size ranges of the analysis except control and safety equipment and electrical upgrades for the hydrogen systems, which are assumed to be fixed costs. Table 10 lists the financial parameters used in the analysis.

Table 9. Equipment Costs for Load-Leveling and Vehicle-Refueling Scenarios

Equipment Costs $2010					
	Unit	Equipment Size Range	Cost Unit	Cost (Installed) [replacement/ refurbishment % of installed cost/interval]	Installed Cost Reference
Electrolyzer	kW	105 – 1,013	$/kW input	~$600 [25%/10 years]	HTAC (2011) ($750 including all balance of plant and indirect costs. DOE Independent Review [2009] installed cost ~$540/kW [2010])
Hydrogen storage tanks (load leveling)	kg	16 – 780	$/kg H_2	~$1,350	H2A (2012). Installed cost for low pressure storage
Hydrogen storage tanks (vehicle refueling)	kg	75 – 165	$/kg H_2	~$1,350 – $1,400	H2A (2012). Installed cost for low pressure and cascade storage
Hydrogen storage compressor + balance of plant, installed (load leveling)	kW	4 – 20	$/kW	$11,000 – $7,200 [100%/10 years]	H2A (2012)
Hydrogen storage compressor (vehicle refueling)	kW	5 – 44	$/kW	$10,400 – $2,600	H2A (2012)
Hydrogen fuel cell	kW	15 – 125	$/kW	~$950 [30%/15 years]	HTAC (2011)
Hydrogen dispenser	—	1	$/unit	~$64,000	H2A (2012)
Zinc-air battery	kWh	600 – 6,000	$kWh	$315	Rastler (2010). Based on max kWh in “storage” at any time
Electrical upgrades and charging stations	—	—	$	5% of installed battery cost	HTAC (2011)

Equipment Costs $2010					
	Unit	Equipment Size Range	Cost Unit	Cost (Installed) [replacement/ refurbishment % of installed cost/interval]	Installed Cost Reference
PV system	kW	180 – 1,070	$/kW installed	~$2,500	HTAC (2011) (Barbose et al. [2012] installed cost for >100kW residential or commercial systems ~$4.75/W $2011)
Indirect Costs	Site preparation, engineering, contingency, permitting		% of installed capital cost	28%	H2A (2012)
Energy Cost					
Levelized cost of grid electricity for building supply without a PV/storage system	$0.12	$/kWh			
Revenue for electricity sold	$0.12	$/kWh			

Notes and assumptions:
1. Vehicle-refueling storage systems include low-pressure tanks (~$1,000/kg) and one cascade storage system (~$1,700/kg, 65 kg H_2 in a three-tank system).
2. For the vehicle-refueling systems, one primary compressor is assumed for both low-pressure and cascade storage: ~2.4 kW compressor power/(kg/h) H_2 flow rate.
3. The compressor system assumes a 200 psi input pressure and a 3,600 psi output pressure.
4. Model parameters are based on a 2020 planning timeframe.
5. Model parameters assume a manufacturing scale of 1,000 systems per year.

Table 10. Financial Analysis Parameters

Model Parameter	Units	Value
Insurance	% of initial direct capital	2%
Annual O&M rate	% of initial direct capital	2%
Inflation rate	%	2%
Total tax rate		0%
Reference dollar year for costs		2010
Financing	Debt financing, 15 years	100%
Interest rate on debt		8%
Real, after-tax rate of return required		0%
System Life	years	30

Notes and assumptions:
1. Annual O&M costs are calculated as a percent of initial capital and include the periodic replacement of components. Compressor system cost is scaled on the hydrogen flow rate in kg/day of flow.

3.1 Load Leveling

The LCOE from the storage system for each of the scenarios is listed in Table 11. The total direct capital cost and LCOE for the system, including the PV system cost, are calculations of the total cost of energy supplied by the combination of the PV system directly supplying electricity to the building plus the cost of routing some of the electricity through the storage system. Credit is taken for any electricity that is sold back to the grid. Electricity sold back to the grid is assumed to be sold at 12¢/kWh, which is the same price as supplementary electricity purchased from the grid. For the total direct capital cost and LCOE without the PV system costs, the costs presented are for the storage system only, and the LCOE applies only to the electricity output from the storage system. In this case, electricity from the PV system to the electrolyzer is assumed to be "free," and the costs presented represent only the cost of purchasing the equipment and non-energy operating costs for the storage system. If the electricity that is routed to the storage system could be sold for 6¢/kWh instead, the cost of electricity to the electrolyzer could be assumed to be worth 6¢/kWh. Recalculating the costs assuming that electricity routed to the electrolyzer costs 6¢/kWh, and using the 1,200-m^2 PV system case as an example, illustrates the effect of the additional cost. For the 1,200-m^2 PV case, about 32,000 kWh of electricity are produced from the storage system. At zero cost for the electricity supply to the electrolyzer, the cost of output electricity is about $1.09 per kWh. This cost increases to $1.26/kWh if the input electricity is 6¢/kWh. The output electricity cost is highly sensitive to the cost of input electricity because of the inefficiency of the electrolyzer/storage/hydrogen fuel cell system. In this case, the round trip efficiency of the storage system is between 35% and 40%, resulting in about 2.5 kWh electricity used for every kWh of electricity produced from the fuel cell.

The LCOE for the full systems increases for the larger systems because of the high PV system costs, but variations in equipment utilization make the 7,000-m^2 system overall slightly lower cost than the 4,000-m^2 system. The 7,000-m^2 system has better utilization of the electrolyzer than the 4,000-m^2 system: 3,619 hours/year operating at an average of 84% of peak output for the 7,000-m^2 system, and 3,265 hours/year operating at an average of 39% of peak output for the 4,000-m^2 system. However, the fuel cell utilization is better for the 4,000-m^2 system than for the 7,000-m^2 system (5,065 hours/year at 55% of peak [4,000-m^2 system] vs. 4,388 hours/year at 45% of peak [7,000-m^2 system]). In the case of the 7,000-m^2 system, electricity produced by the PV system must be sold to the grid at a lower cost than the cost of generating it (12¢/kWh vs. 15¢/kWh, respectively).

In contrast, focusing only on the cost of storing electricity shows the opposite trend. The storage system is used much more effectively for higher penetrations of PV so the costs of stored electricity decrease. Careful attention must be paid to matching the storage system to the particular application. There are many variables including the electrolyzer size, storage system size, and fuel cell size that must be considered together with the building load characteristics and PV system output to optimize the system to achieve the goals for the application.

Table 11. Load-Leveling System Costs with and without PV Costs Included

Scenario	Total Direct Capital Cost Including PV System ($000)	LCOE of Electricity (Direct Supply + Electricity from Storage) (¢/kWh)	Total Direct Capital Cost without PV System ($000)	LCOE of Stored Electricity (¢/kWh)[a]
1,200-m^2 PV/storage system	$727	33	$271	109
4,000-m^2 PV/storage system	$2,958	57	$1,438	62
7,000-m^2 PV/storage system	$3,393	45	$733	36

[a] Levelized costs include all direct and indirect costs for the apportioned cost of the PV system, hydrogen/battery production, storage and delivery, and replacement and operating expenses over the life of the system.

The equipment cost breakdown for scenarios analyzed is shown in Figure 18. The balance-of-plant components, including electrical upgrades and control and safety equipment, are included in the category labeled "Hydrogen Compressor." In these scenarios, the hydrogen storage system (compressor and storage tanks) comprises more than 50% of the non-PV system costs. The electrolyzer cost is higher than the fuel cell cost in all cases even though the electrolyzer is lower cost than the hydrogen fuel cell on a per-kW basis. This occurs because the electrolyzer must be sized to capture electricity produced by the PV system during a relatively short period in the middle of the day when PV output peaks and demand is relatively low. In contrast, the hydrogen fuel cell can be sized to slowly feed electricity back to the building load during a relatively long period when demand is steady and there is no PV output. The results of an analysis of the sensitivity of the 4,000-m^2 PV system case output electricity cost to equipment cost is presented in Figure 19.

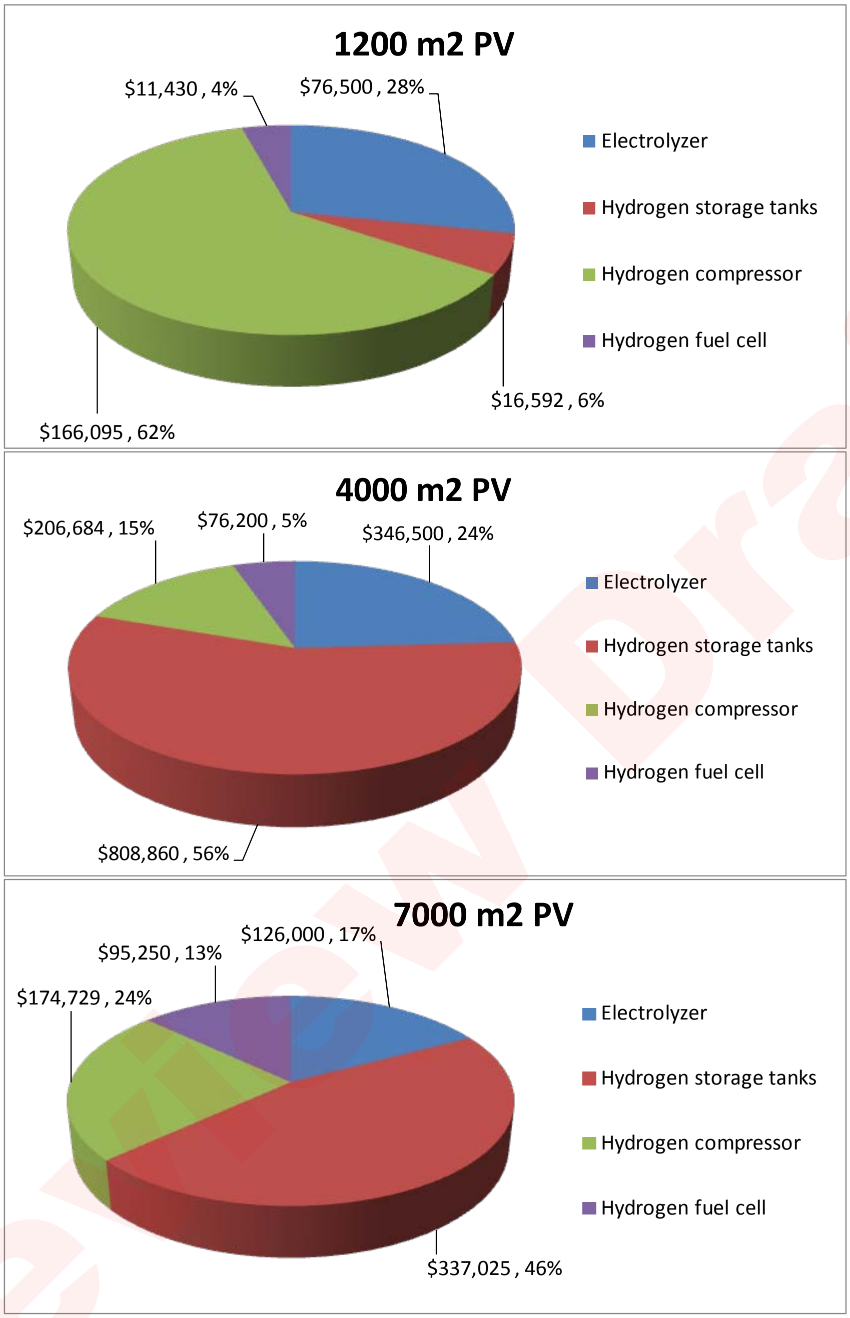

Figure 18. Capital cost breakdown for hydrogen storage systems for 1,200-m^2 PV system (top), 4,000-m^2 PV system (center), and 7,000-m^2 PV system (bottom)

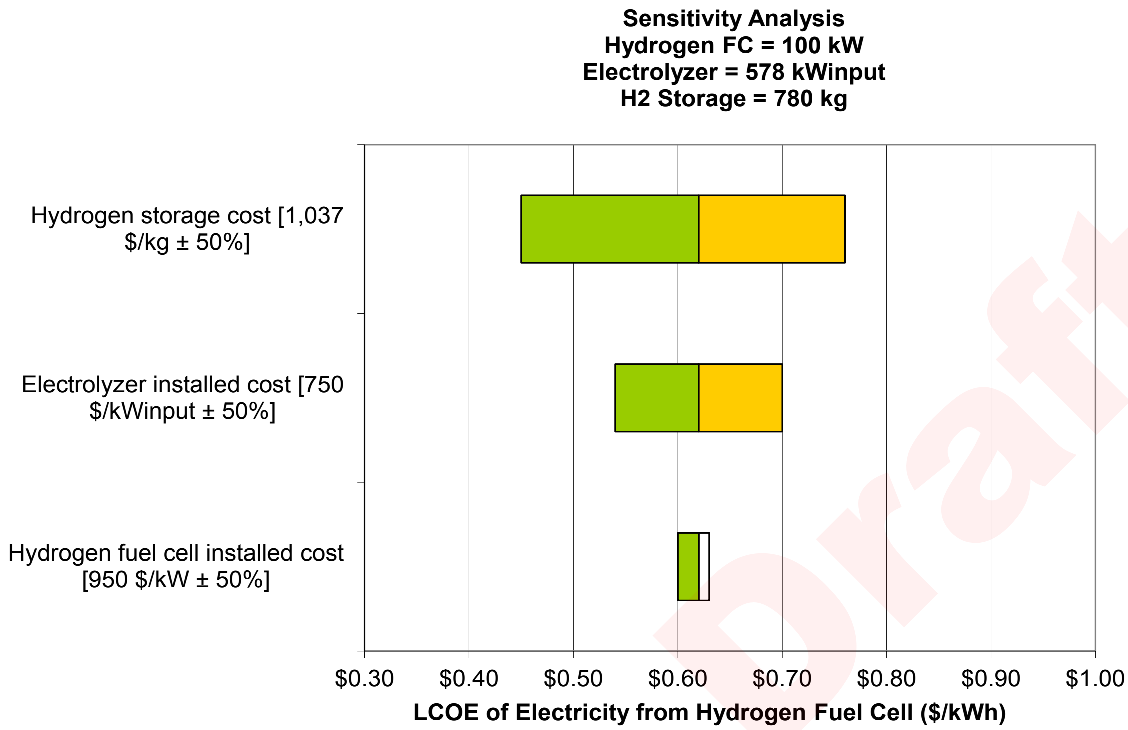

Figure 19. Sensitivity of output electricity LCOE to equipment cost for the 4,000-m^2 PV system case

3.2 Vehicle Refueling

Figure 20 shows the total system capital costs for Case 1. The PV system dominates the capital costs followed, for the larger systems, by the electrolyzer. Figure 21 shows the capital cost breakdown for the hydrogen system only. The electrolyzer accounts for 16% (1,200-m^2 PV system), 40% (4,000-m^2 system), and 45% (7,000-m^2 system) of the hydrogen system costs. For the smallest PV system, hydrogen storage accounts for the largest capital cost (22%).

Figure 22 compares the hydrogen system capital costs of Case 1 versus Case 2. For the smallest PV system, Case 2 capital costs are substantially higher, primarily owing to higher hydrogen storage and electrolysis costs. For this system, 96% more hydrogen is produced annually in Case 2 than in Case 1 because the extra PV output used to produce hydrogen before noon in Case 2 accounts for almost as much total hydrogen production as the PV output in excess of the building load. Thus, the electrolyzer and hydrogen storage must be substantially larger in Case 2 than in Case 1 to accommodate the higher hydrogen production rates and extra hydrogen storage. As the PV system size increases, the contribution of the extra morning hydrogen production becomes smaller. For the 4,000-m^2 system, Case 2 produces only 17% more hydrogen annually than Case 1, and Case 2 capital costs are only slightly higher. For the 7,000-m^2 system, Case 2 produces only 9% more than Case 1, and the capital costs are almost identical.

Table 12 summarizes the Case 1 and Case 2 cost results for both the hydrogen and battery-electric vehicle refueling systems. On a per-mile basis, electric storage/refueling is 30% to 60% of the cost of hydrogen storage/refueling. The largest differential is for the 1,200-m^2 PV system, for which the hydrogen capital cost is about twice as high as the battery-electric capital cost (Figure 23). For the 4,000- and 7,000-m^2 PV systems, the hydrogen capital costs are lower than the battery-electric capital costs; however, the higher efficiency of the battery-electric vehicle system (29 kWh/100 miles for electric vehicles versus 55.6 kWh/100 miles for fuel cell electric vehicle (DOE 2013) still results in a lower per-mile cost for the battery-electric vehicle system.

In both cases, for the hydrogen and electric systems, diverting more electricity from the PV system for vehicle refueling improves the economics; this effect is more pronounced for the hydrogen system. The best hydrogen cost is from the Case 2 7,000-m^2 PV system. In this scenario, about 90% of the PV output goes to hydrogen production or battery storage, and the PV system supplies 28% of the building load. The hydrogen system produces about 32,000 kg of hydrogen per year (about 90 kg/day), enough to supply 159 vehicles, at a cost of \$11/kg or 19¢/mile.

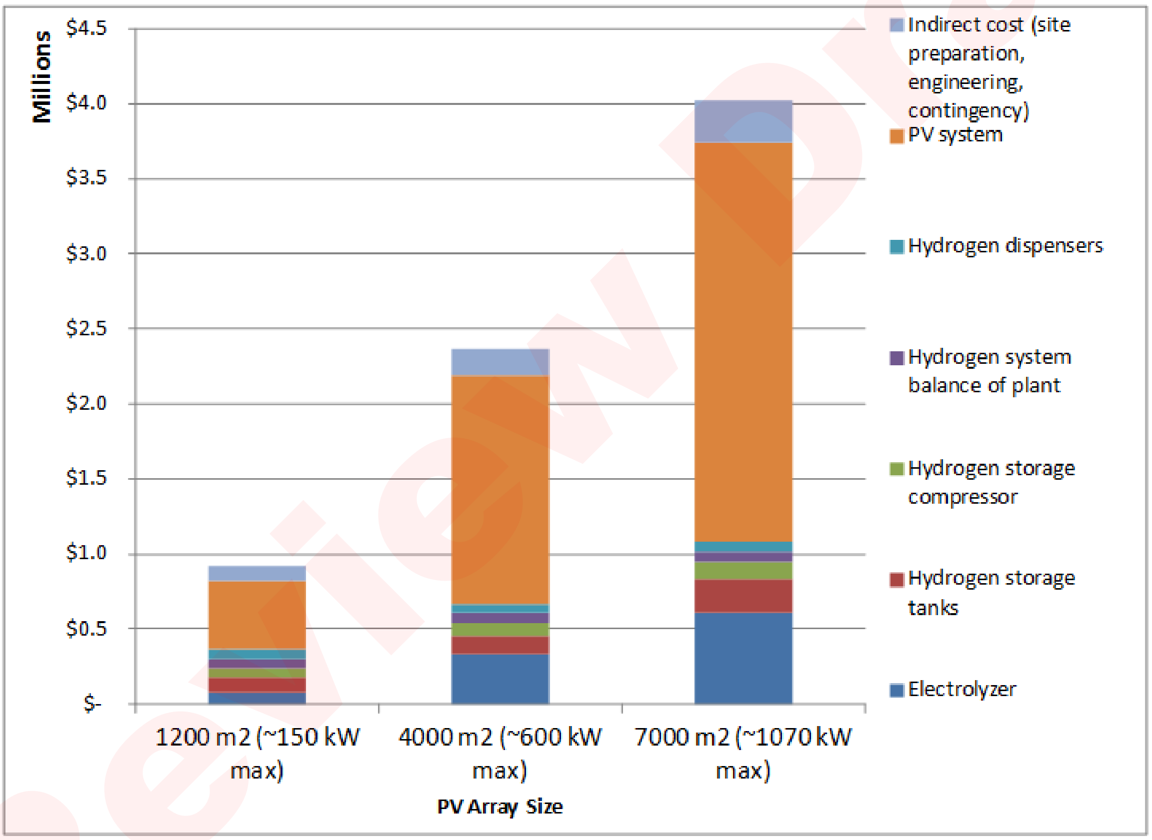

Figure 20. Total PV-hydrogen system capital costs (Case 1)

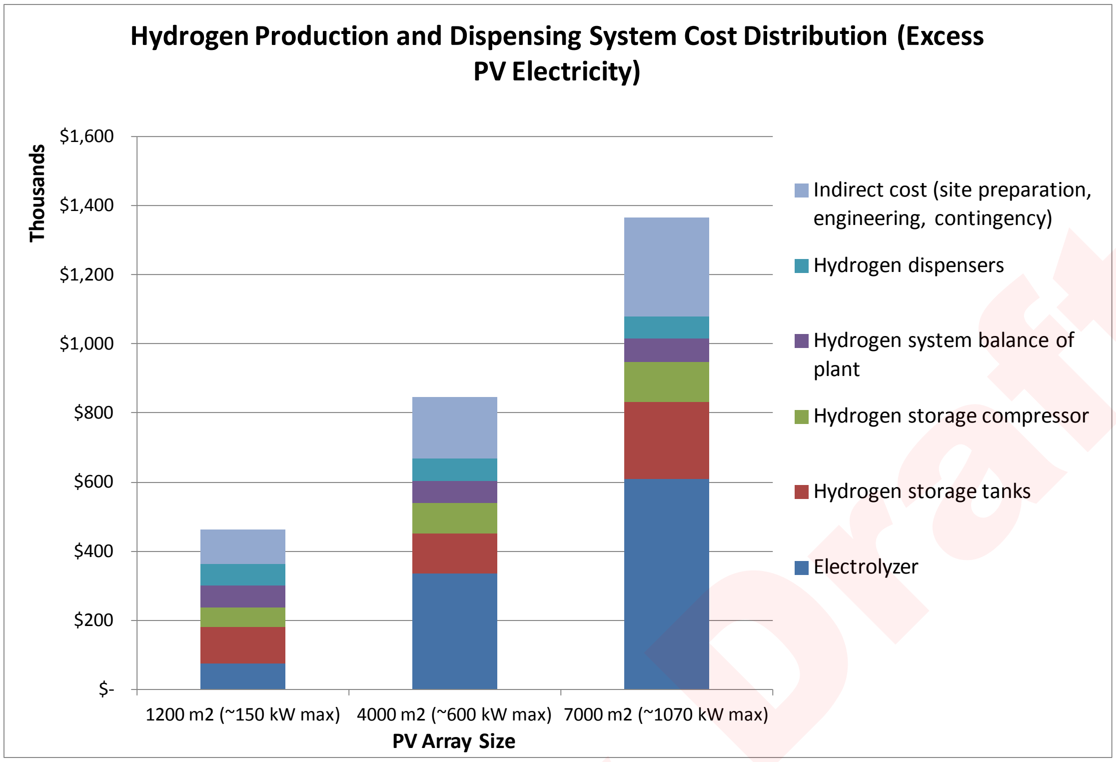

Figure 21. Hydrogen system capital costs (Case 1)

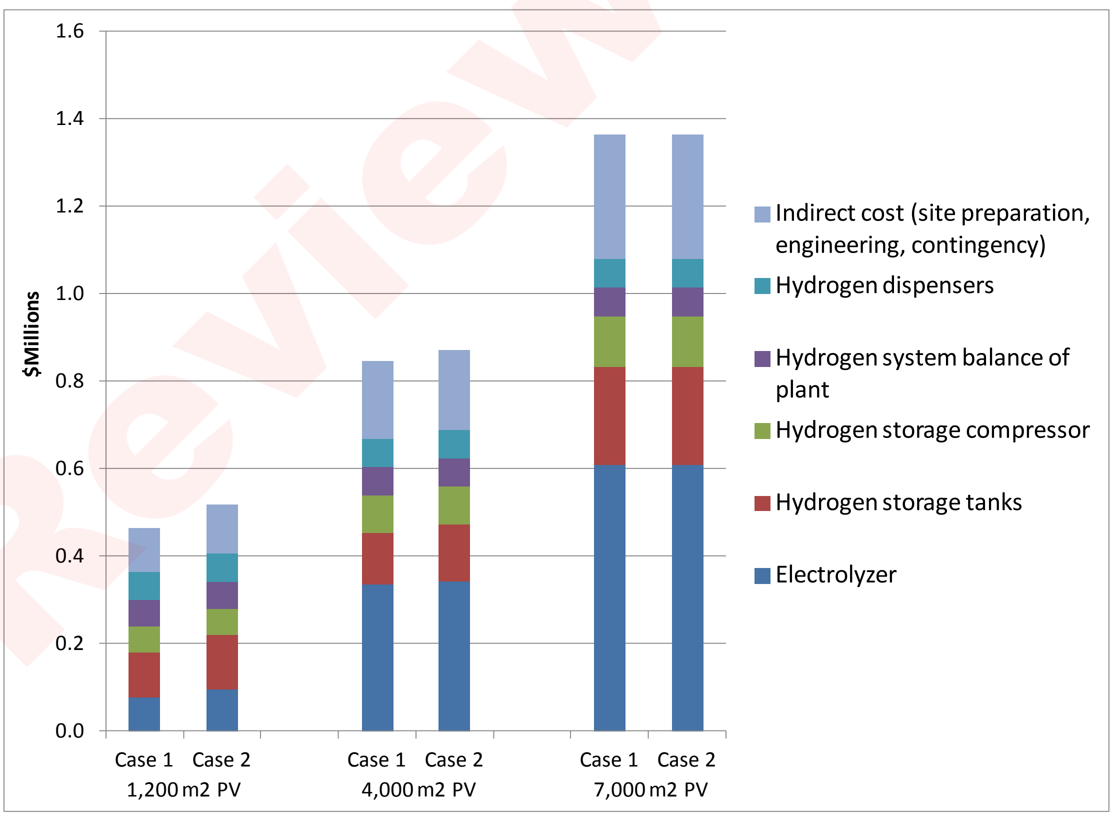

Figure 22. Comparison of hydrogen system capital costs between Case 1 and Case 2

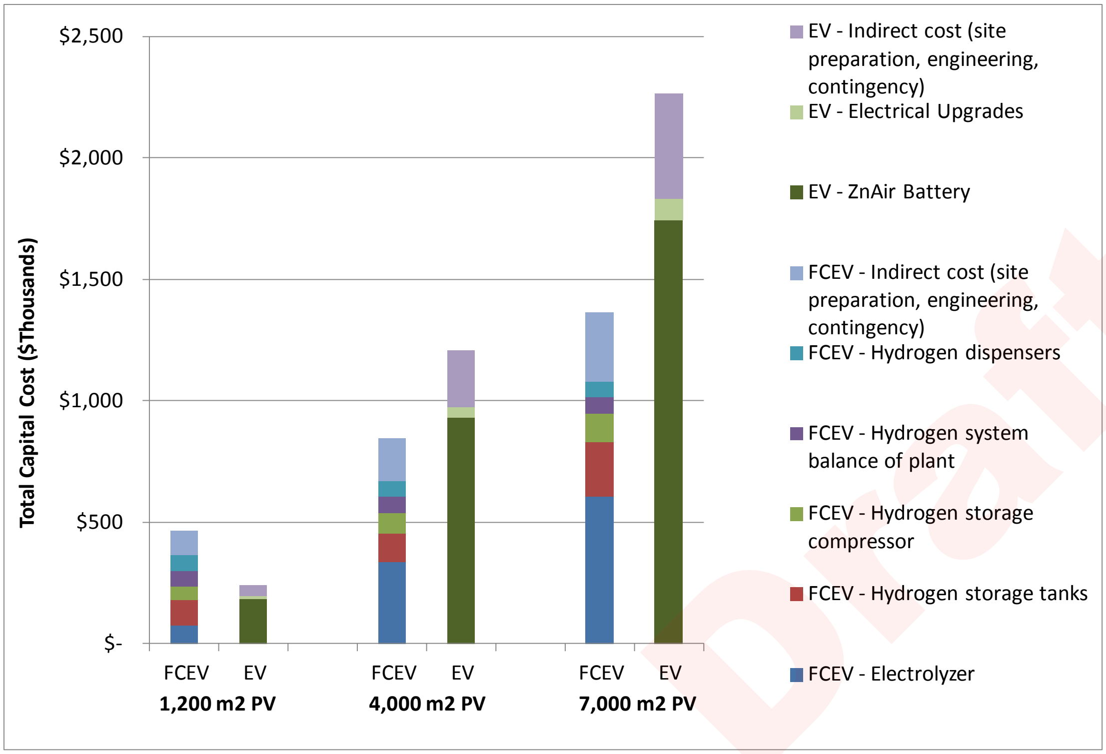

Figure 23. Capital costs of hydrogen (fuel cell electric vehicle [FCEV]) and battery-electric (electric vehicle [EV]) systems, Case 1

Table 12. Summary of Vehicle Refueling Cost Results

Hydrogen for Fuel Cell Vehicles[a]								
	Case 1 (Excess Electricity)				Case 2 (Excess Electricity + Morning Output)			
PV Size (m^2)	Production (kg H_2/yr)	Vehicles Served	H_2 LCOE ($/kg)	H_2 Cost (¢/mi)	Production (kg H_2/yr)	Vehicles Served	H_2 LCOE ($/kg)	H_2 Cost (¢/mi)
1,200	1,804	9	34	56	3,541	17	22	38
4,000	14,564	72	13	22	16,985	84	12	21
7,000	29,274	146	12	20	31,898	159	11	19
Electricity for Battery-Electric Vehicles[a]								
	Case 1 (Excess Electricity)				Case 2 (Excess Electricity + Morning Output)			
PV Size (m^2)	Production (kWh/yr)	Vehicles Served	Elec. LCOE ($/kWh)	Elec. Cost (¢/mi)	Production (kWh/yr)	Vehicles Served	Elec. LCOE ($/kWh)	Elec. Cost (¢/mi)
1,200	61,726	17	0.57	17	121,936	35	0.45	13
4,000	500,755	143	0.41	12	585,475	168	0.40	12
7,000	1,008,212	289	0.39	11	1,100,877	316	0.39	11

[a] Levelized costs include all direct and indirect costs for the apportioned cost of the PV system, hydrogen/battery production, storage and delivery, and replacement and operating expenses over the life of the system. For the 4,000- and 7,000-m^2 PV systems, the hydrogen capital costs are lower than the battery-electric capital costs; however, the higher efficiency of the battery-electric vehicle system (29 kWh/100 miles for electric vehicles vs. 55.6 kWh/100 miles for fuel cell electric vehicles (DOE 2013) still results in a lower per-mile cost for the battery-electric vehicle system.

4 Conclusions

These simple analyses show the potential application of hydrogen production, storage, and electricity-generation technologies for community load leveling and vehicle refueling. Although the results do not show a clear advantage for hydrogen load leveling or vehicle refueling, the analysis does indicate that the economics could be improved especially for larger systems.

The primary goal of the load-leveling scenario was to evaluate storage systems for load leveling under the constraint of a limited grid/transformer size. The systems were sized to meet this goal, but not fully optimized for cost. The results of the analyses indicate that storage systems are more cost effective for higher penetrations of renewable electricity generation. In all cases, however, the electricity produced by the storage system was more expensive than grid electricity. Therefore, the storage system must provide benefits in addition to cost, such as relieving grid congestion and/or providing backup power, in order to be cost effective. A sensitivity analysis for equipment costs for the 4,000-m^2 energy storage case revealed that the LCOE of output electricity was most sensitive to the hydrogen storage tank cost (Figure 19). However, the overall system cost is also highly dependent on the configuration of the system and the relative sizes/capacities of the various pieces of equipment as shown by the wide variation in the relative sizes of equipment for the three PV system sizes analyzed (Figure 18).

In all scenarios, the storage system reduced peaks and valleys in grid demand and energy fed onto the grid (see Figure 15). The leveling effect was the most pronounced for the larger systems. However, the analysis also showed that additional optimization and/or control of the storage systems would be needed to completely eliminate large spikes in energy flow. For the 4,000-m^2 PV system case, which is most closely matched to the building demand, the storage system and vehicle systems reduced the daily fluctuations in grid demand by almost 80% and completely eliminated reverse flow of electricity to the grid. The 4,000-m^2 system storage scenario was also able to accommodate the seasonal variation in PV output, allowing for all of the energy produced by the PV system throughout the year to be used onsite. Storage that can smooth seasonal variations as well as daily variations in PV system output may be advantageous for very high levels of PV penetration.

This brief analysis shows that community level hydrogen refueling using only renewably generated electricity could be accomplished. For the 4,000-m^2 PV system case, the number of fuel cell vehicles that could be refueled roughly matches the total number of vehicles expected for the community size modeled (100 households). The vehicle refueling scenarios were configured so that the storage systems, either hydrogen or battery) were cycled approximately daily with a fairly generous “cushion” for expected fluctuations in demand over the course of a few days or a week. The analysis does not assume that the additional storage accounts for seasonal variations in hydrogen/electricity demand or production. Month-to-month variations in production are not large. However, the high and low production months (March and December, respectively) only roughly correspond to expected high and low demand months (June–August and November–January, respectively). There is also a predictable dip in PV output during the hottest part of the summer, when fuel demand is expected to peak. Although the analysis did not explicitly address seasonal variations in production or demand, it is likely that the additional storage modeled would be sufficient to accommodate them. The vehicle refueling scenarios also provide as much smoothing of the PV system output/grid demand as the energy storage scenarios (see Figure 15). This smoothing of PV/grid interactions could be vital for integration of high levels of distributed PV.

The vehicle-refueling analysis shows the potential for community-level hydrogen refueling using only renewably generated electricity (Table 12). With the 4,000-m^2 PV system, the number of fuel cell vehicles served (70 – 80) roughly matches the modeled community size (100 households). The levelized hydrogen cost ranges from \$34/kg (\$1.01/kWh) for the 1,200-m^2 Case 1 system to \$11/kg (\$0.34/kWh) for the 7,000-m^2 Case 2 system. The cost of battery storage of electricity for electric vehicles ranges from \$0.57/kWh to \$0.39/kWh, also decreasing with increasing system size. The hydrogen system cost reduction for the larger systems is due, as for the load-leveling system, to better utilization of the equipment. The hydrogen system configuration is also more flexible than the battery system because there are more independent pieces of equipment. For small systems, this is a disadvantage, but for larger systems the increased flexibility reduces costs because an incremental increase in hydrogen storage capacity per kWh (hydrogen tank) is less expensive than an incremental (per kWh) increase in electrochemical storage. Even though the hydrogen system is lower cost than the battery system for the largest storage case, the electric vehicle is less expensive on a fuel ¢/mile basis because of its higher efficiency in comparison to the fuel cell vehicle.

5 Future Work

This analysis did not show a clear advantage for hydrogen load leveling or vehicle refueling. However, the analysis does indicate that the economics could be improved, especially for larger systems, with careful optimization of the system configuration and equipment. Several areas of further research that might enhance understanding of the economics of community level hydrogen energy include:

- Explore more realistic scenarios for dealing with seasonal variation in PV output
- Explore methodologies for optimizing hydrogen system configuration
- Explore the impact of incentives and net metering for economics.

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