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Economic Analysis of Large-Scale Hydrogen Storage for Renewable Utility Applications

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Economic Analysis of Large-Scale Hydrogen Storage for Renewable Utility Applications

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Contract #1024882

Abstract

The work reported here supports the efforts of the Market Transformation element of the DOE Fuel Cell Technology Program. The portfolio includes hydrogen technologies, as well as fuel cell technologies. The objective of this work is to model the use of bulk hydrogen storage, integrated with intermittent renewable energy production of hydrogen via electrolysis, used to generate grid-quality electricity. In addition the work determines cost-effective scale and design characteristics and explores potential attractive business models.

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Executive Summary

Results are presented for a base case in which wind energy is converted to stored hydrogen during the high-wind, low-load periods; the stored hydrogen is used to fuel a utility scale fuel cell during peak-periods of demand. Results are also presented for the case in which the excess wind power would otherwise be curtailed, or spilled, and thus is available for charging storage at no cost. Various energy storage technologies are compared, as listed in Table E1.

Table E1. Technologies compared in this study.

Technology
Advanced lead-acid batteries
Sodium sulfur batteries
Flow batteries
Compressed Air Energy Storage
Pumped hydroelectric storage
Bulk hydrogen energy storage from electrolysis with fuel cell power generation

Results of the comparison for the spilled wind case show a hydrogen system at DOE target costs to be competitive with other large-scale technologies, as shown in Figure E1.

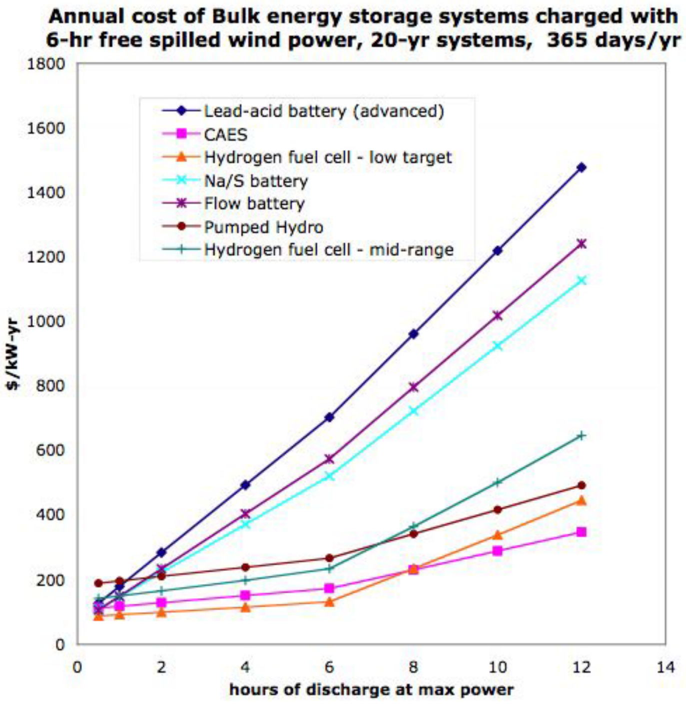

Figure E1. Annual cost results for the case of spilled wind.

In a benefit / cost analysis, the present value of benefits exceeds the present value of costs, on a $/kW basis, for the case of spilled wind, especially at target costs, as shown in Figure E2. On a $/kWh basis, the comparison is even more attractive, as shown in Figure E3.

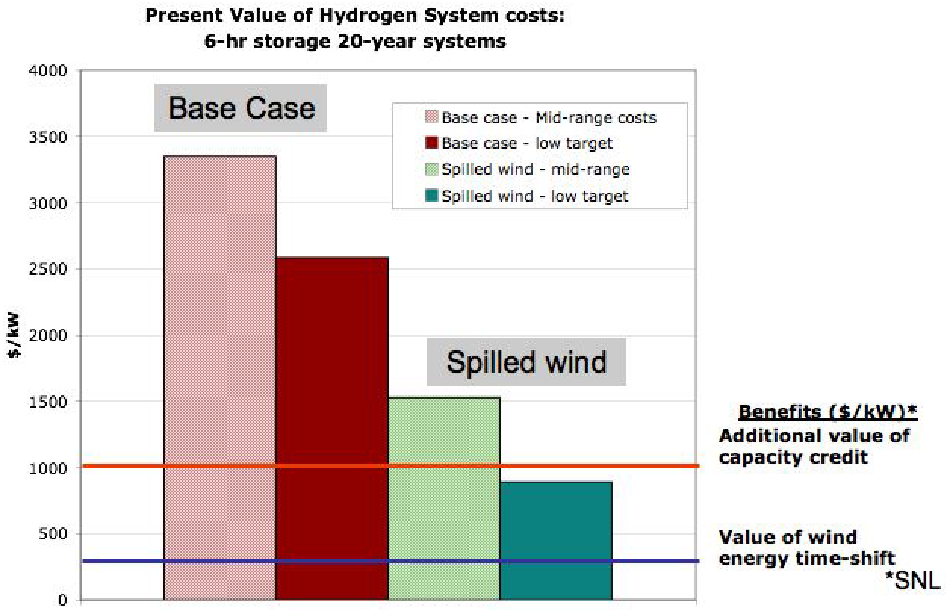

Figure E2. Present value of costs and benefits for hydrogen systems on a $/kW basis.

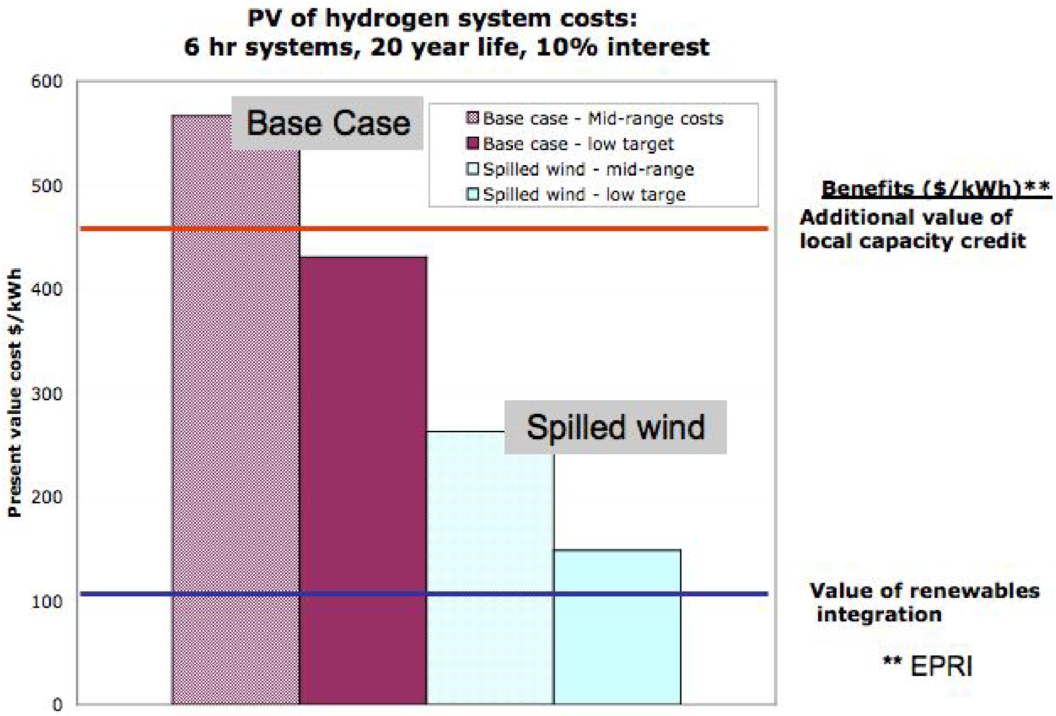

Figure E3. Present value of costs and benefits for hydrogen systems on $/kWh basis.

Some conclusions from this study include the following:

- Hydrogen energy storage is an ideal match for renewables of all scales, especially large-scale wind.
- Hydrogen with renewables is effective for reducing green house gases from power generation.
- Underground storage offers opportunities to store H_2 because of large capacity and competitive cost.
- Stationary hydrogen and fuel cell applications complement the electric system across a spectrum of sizes:
  - Residential and communities
  - Distributed generation
  - Load and source - leveling
- Market opportunities need development.

Not discussed in this report, but also true

- H_2 produced by electrolysis from renewable energy can also supply fuel for transportation.

Recommendations for further work include:

- Add **scaling** considerations to utility business model, considering the spectrum of value propositions, both at much large scale of storage, and smaller scale of storage.
- Add **location** considerations to cost and benefit analysis.
- Build **third-party** (non-utility) opportunities into business model.
- Continue discussions and deliberations with **commercial** interests regarding market potential.

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1 Introduction

1.1 Objectives

The US Department of Energy Fuel Cell Technology program has among its prime goals to accelerate the commercialization and deployment of fuel cells and to facilitate the adoption of fuel cells across government and industry. Among the industries targeted is the electric power sector, and here the objective is to enable greater penetration of clean renewable energy production while addressing the market for large-scale storage of hydrogen and hydrogen technologies. [1]

The work reported here supports the efforts of the Market Transformation element of the DOE Fuel Cell Technology Program. The portfolio includes hydrogen technologies, as well as fuel cell technologies. The overall goals of the Market Transformation program are [2]:

- Ensure continued technology utilization growth for domestically produced hydrogen and fuel cell systems
- Lower life cycle costs of fuel cell power by identifying and reducing non- technical barriers

One of the major objectives is to “Catalyze key implementation projects and partnerships with state and local governments and other stakeholders.”

This work is a step toward helping meet the overall goals of the Market Transformation program. The objective of this work is to model the use of bulk hydrogen storage, integrated with intermittent renewable energy production of hydrogen via electrolysis, to determine cost-effective scale and design characteristics, and to explore potential attractive business models.

1.2 Background

Previous work by this author [3,4] and others [5] has explored the potential use by the electric utility industry of hydrogen produced and stored in bulk. These studies show promise in some applications, especially where large scale is demanded and particularly in conjunction with intermittent energy resources such as wind.

The use of hydrogen will compete with other energy storage technologies, including modular systems, such as batteries, and other large-scale systems such as compressed air energy storage (CAES) and pumped hydro storage. The major weakness in the hydrogen system is the relative inefficiency of energy conversion through the electrolysis and fuel cell subsystems. The major advantage is lower storage cost and higher volumetric energy density.

The underlying premise of this work is to explore those opportunities where the relative inefficiency becomes insignificant compared to relatively inexpensive storage, and where the need for storage is imperative to counter inconsistent electricity production. The case explored in detail here involves hours of wind power that is produced when there is insufficient load to use it. This occurs in many places in the United States where wind generation has been installed, often to take advantage of renewable energy credits or to meet state or regional requirements of a Renewable Portfolio Standard (RPS).

Current European studies are looking at extremely large-scale storage of hydrogen to buffer variable wind power production for the European grid. These studies suggest that hydrogen is the only solution possible for such large scale. [6,7] A review of this and other background work is included in Appendix A.

1.3 Scope of work

The work reported here has been carried out in five activities as listed below:

1. Update utility energy storage model to include purchase of curtailed wind energy.

   The Longitude 122 West energy storage model has been developed under previous Sandia contracts to evaluate system costs, primarily for load-leveling and distributed generation (DG) applications. [3] For this work, it was modified to include the purchase of off-peak curtailed wind power.

2. Update costs for fuel cell and hydrogen systems and other storage technologies and compare.

   The energy storage model was modified to consider bulk hydrogen storage, either in gas tanks or underground storage. The costs of all the alternative technologies were also updated. Costs are presented on the basis of annual cost $/kW-yr.

3. Perform sensitivity analyses.

   Hydrogen system costs were parametrically varied for sensitivity analyses. Economic and operational parameters were also varied.

4. Establish utility / renewables business case.

   In discussions with a number of utilities and grid operators, the case of excess wind for a period up to 6 hours was established for analysis. The scenario assumes hydrogen production by electrolysis.

5. Make benefit / cost estimates and draft business model.

   Benefit / cost estimates are best made on a present value basis, as the benefits literature has long reported benefits in this way. [8,9] This requires the costs to be converted to present value for comparison. The business model in this report is presented for consideration by power providers. The study of additional opportunities is recommended for future work.

2 Approach

The approach to this work proceeds along the following steps:

- Assume a design concept in which energy storage is connected to an electric grid that includes power generation from wind. The storage system is charged from the grid and discharged back to the grid.
- Calculate the capital cost of the energy storage system, dependent on the size of the storage system, i.e., the number of hours of stored energy for full power discharge.
- Calculate the annual life cycle cost, including the costs of O&M, charging electricity, replacement costs, and capital charge
- Convert to present value for comparison with benefits estimates.

2.1 Energy storage system and components

For most of the storage technologies (such as batteries), charging and discharging makes use of a common power conversion subsystem. This is shown in the simple schematic in Figure 1. This configuration would be representative of most battery systems.

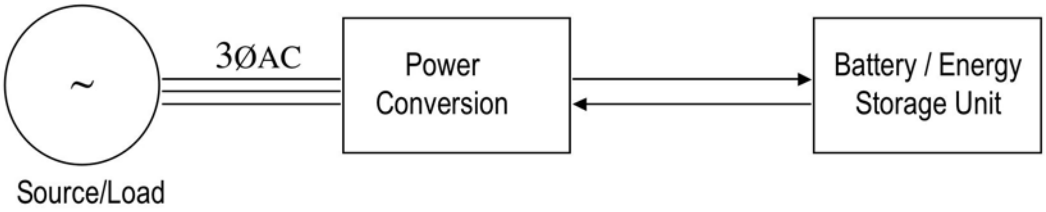


Figure 1. Generic energy storage configuration.

For the hydrogen system, hydrogen is produced by electrolysis, stored in bulk, and utilized in fuel cells to generate electricity, as suggested in Figure 2.

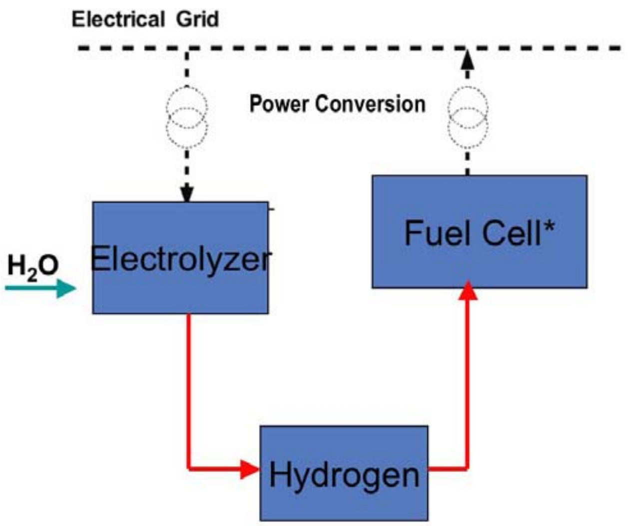


Figure 2. Energy storage configuration for hydrogen and fuel cell system.

For Compressed Air Energy Storage (CAES), the simple concept replaces the electrolyzer with a compressor, the hydrogen storage with gas storage and the fuel cell with a gas turbine. The gas turbine requires input of natural gas, as indicated in Figure 3.

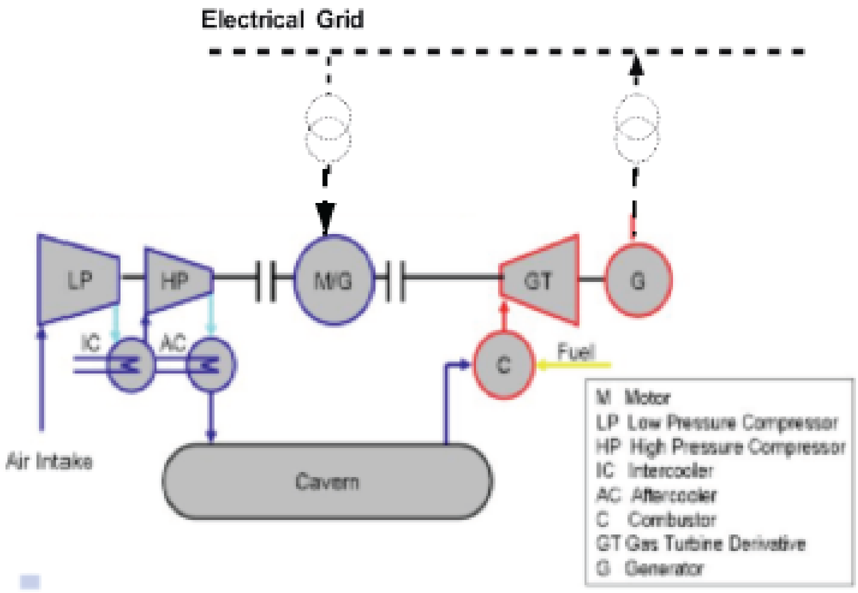


Figure 3. Compressed Air Energy Storage (CAES) configuration.

2.2 Cost analysis

The cost analysis performed in this work follows the same calculation steps reported in earlier work by this author, as documented in References [2,3,10]. For ease of calculation and presentation, all the results are eventually expressed in \$/kW.

For any energy storage system in which the power and energy subsystems are essentially separate units:

Capital Cost = Cost of power equipment + Cost of storage

$\text{Cost}_{\text{total}}(\$) = \text{Cost}_{\text{pcs}}(\$) + [\text{Cost}_{\text{storage}}(\$) + \text{Cost}_{\text{Bop}}(\$)]$

$\text{E}_{\text{storage}}(\text{kWh}) = \text{Power(kW)} \text{ x Discharge time (hr)}$

$\text{Cost}_{\text{total}}(\$) = [\text{P(kW) x Cost}_{\text{pcs}}(\$/\text{kW})] + [\text{Cost}_{\text{storage+BOP}} (\$/\text{kWh}) \text{ x Time (hr) x Power(kW)}]$

$\text{Cost}_{\text{total}}(\$/\text{kW}) = \text{Cost}_{\text{pcs}}(\$/\text{kW}) + \text{Cost}_{\text{storage}} (\$/\text{kWh}) \text{ x Time (hr)}$

This equation shows the importance of the storage time. This defines the minimum size of the storage system.

For the hydrogen energy storage system, the power generation (fuel cell) and hydrogen production unit (electrolyzer) are separate systems, costed separately:

Total Capital Cost = Cost of hydrogen tanks or reservoir + Cost of electrolyzer + Cost of fuel cell

The life cycle annual cost includes all the operating costs of the system, including operation and maintenance (O&M), consumables (electricity) and replacement costs of components that do not have the full life of the system. The annual cost is then calculated as:

Levelized annual cost (\$/kw-yr) =

Cost of capital (carrying charge on initial purchase)
+ Cost of fixed O&M
+ Cost of variable O&M
+ Annualized replacement costs
+ Consumables (fuel and electricity)

The cost of capital depends on the systems life-time and capital charge rate. The costs of fixed and variable O&M have been established in previous studies. The cost of replacements is annualized for capital costs at intervals over the life of the plant. Consumables are only electricity for all energy storage types except CAES, which also consumes natural gas.

The annual costs are converted to present value, as described in Section 6.

2.3 Energy storage technologies

Other energy storage technologies can perform the same function described here for a hydrogen energy storage system. Some battery systems are already operating in conjunction with wind generation facilities, while a number of CAES systems are under construction, in negotiation or under consideration. Depending on the size and location of the system, these alternatives represent viable opportunities.

In the base case, the alternative energy storage technologies presented previously (i.e., three types of batteries, underground (conventional) CAES, and pumped hydro) are compared first with hydrogen systems using current/low cost and performance values, and second with hydrogen systems using DOE target values for cost and performance. The “current” hydrogen system assumes compressed gas storage. The “target” values assume bulk storage in geologic formations.

The battery technologies considered are advanced lead-acid batteries (suitable for daily cycling), sodium-sulfur batteries (designed for optimum storage of 6 to 8 hours), and flow batteries (also designed for “bulk” storage). There are a number of flow batteries on the market. The values used here are most representative of zinc-bromine batteries, but are similar to values for vanadium redox batteries. All the technologies will require maintenance, which is included in the cost stream. The batteries and hydrogen systems will also require period replacement of components and these are accounted for in the analysis.

A list of technologies considered for comparison is shown in Table 1 below.

Table 1. Technologies compared in this study.

Technology	Comments
Advanced lead-acid batteries	In development
Sodium sulfur batteries	Commercial products
Flow batteries	ZnBr is representative, others in various stages of development
Compressed Air Energy Storage	Systems under construction
Pumped hydroelectric storage	Mature technology
Bulk hydrogen energy storage	Two cases: tank storage and underground storage

3 Hydrogen and fuel cells

In this analysis, the hydrogen energy storage system is assumed to consist of a water electrolyzer, bulk storage subsystem and fuel cell for power generation. Although variations on this concept are possible, such as the use of a turbine generator or reciprocating combustion engine for power production [5], these are not considered in this report. The alternative storage concepts include only compressed gas storage and underground storage. The underground storage is less expensive for very large scale storage, as described below, but has a siting disadvantage. The sensitivity to the cost is somewhat minor, as also described in the results section.

This study is not focused on technology description or analysis, but rather on economic analysis. Therefore, there is no detailed discussion of the various components. The electrolyzer and fuel cell are both assumed to be proton exchange membrane (PEM) types, as this has been a focus of the DOE program. The analytic approach is independent of the actual devices.

The compressed gas storage assumes inexpensive, large-scale tanks. The underground storage is assumed to be in salt caverns, but aquifer and depleted gas fields are also possible. The footprints of the various systems have not been calculated in this phase of the work.

3.1 Costs and target costs

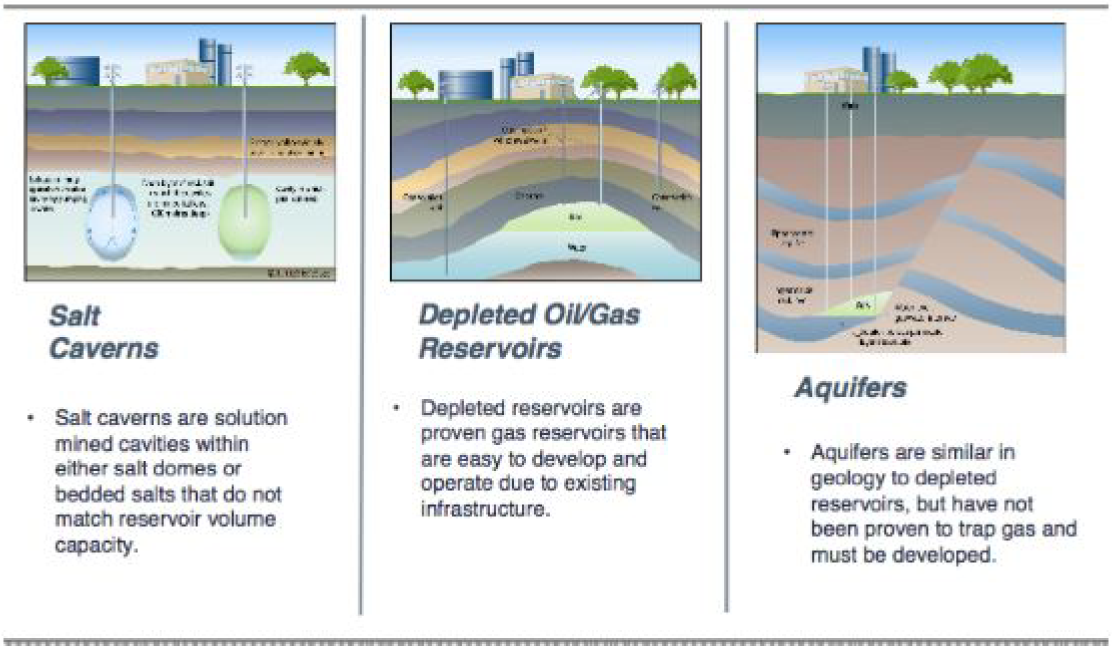
The costs and performance values used in the analysis in this study are shown in Table 2 below. The electrolyzer system cost includes a compressor and the fuel cell system cost includes power conversion to grid-scale ac power. These values are consistent with those in the references listed in the far right column. Specifically, mid-range and the “low target cost” for electrolyzers are those used in Reference [5]. As of the time of this writing, the newest DOE hydrogen program Multi-year Program Plan [11] maintains these target values, or in some cases lowers them.

Table 2. Cost and efficiencies of hydrogen technologies in this study.

	Current efficiency	**Target efficiency**	**Current cost - mid**	**Target cost - low**	**References**
Electrolyzer	73.5%	75%	340 $/kW	125 $/kW	[5], [11], [1]
Gas storage	NA	NA	15 $/kWh	2.5 $/kWh	[5], [12]
Underground storage	NA	NA	0.3 $/kWh	0.3 $/kWh	[5], [13]
Fuel cell	55%	58%	500 $/kW	100 $/kW	[11], [1]

3.2 Underground storage

Underground storage has been used for bulk hydrogen storage. Several existing salt caverns can be found in the UK and US [14]. In Europe, the company KBB has proposed bulk hydrogen storage in salt caverns because of the high volumetric energy density of hydrogen, even at modest pressure. [15] Work to develop a life-cycle cost model has been underway at Sandia National Laboratories for several years, for the reservoir types shown in Figure 4. [13,16]



- Salt caverns are solution mined cavities within either salt domes or bedded salts that do not match reservoir volume capacity.

- Depleted reservoirs are proven gas reservoirs that are easy to develop and operate due to existing infrastructure.

- Aquifers are similar in geology to depleted reservoirs, but have not been proven to trap gas and must be developed.

Figure 4. Underground storage options for hydrogen.

On a per kWh basis, underground storage would be much less expensive than tank storage. However, it is only reasonable to develop for very large scale. Figure 5 shows the capital cost components for the base case hydrogen energy storage system in this study. The storage subsystem is a minor part, even with tank storage.

Figure 6 shows the annualized cost of the hydrogen storage system comparing both base case and target case with both tank and underground storage. Whereas the underground storage will be attractive at very large scale, it is not particularly significant at this modest scale, where convenient siting is likely to be more important.

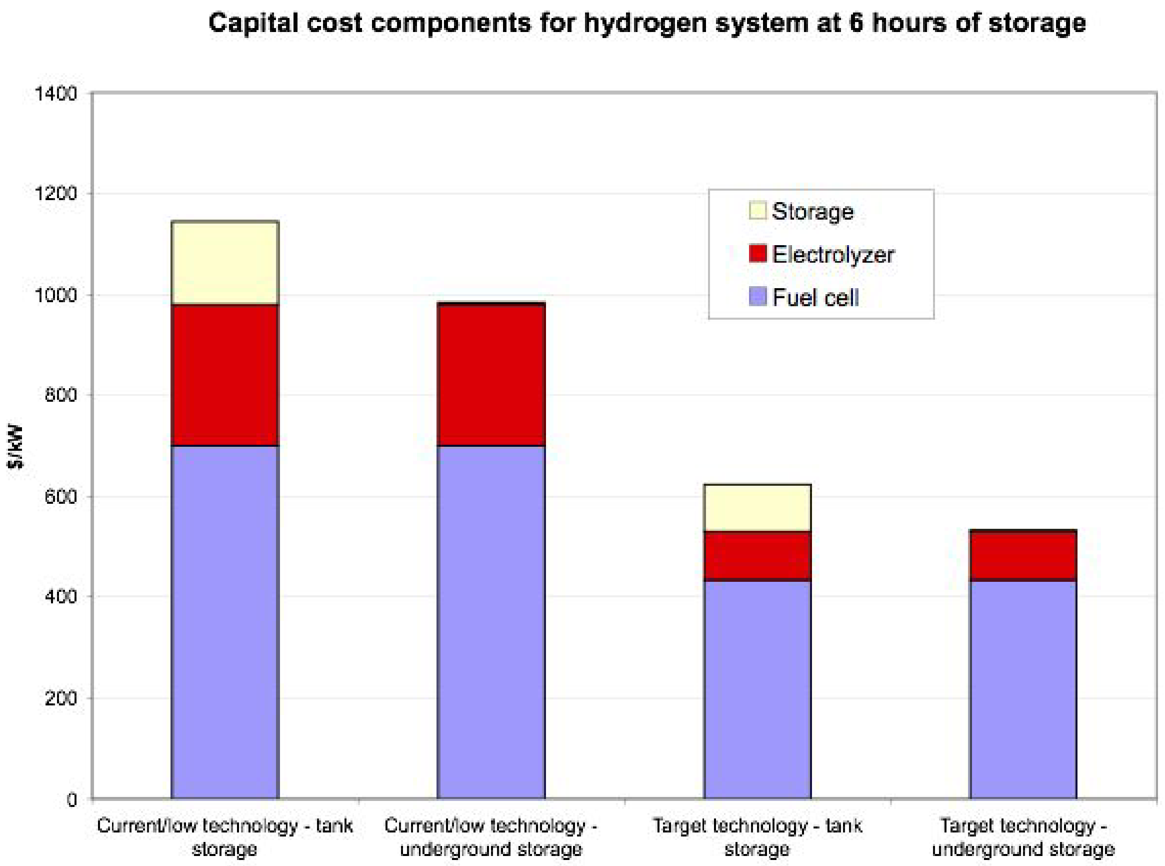


Figure 5. Capital cost components for 6-hr hydrogen energy storage systems.

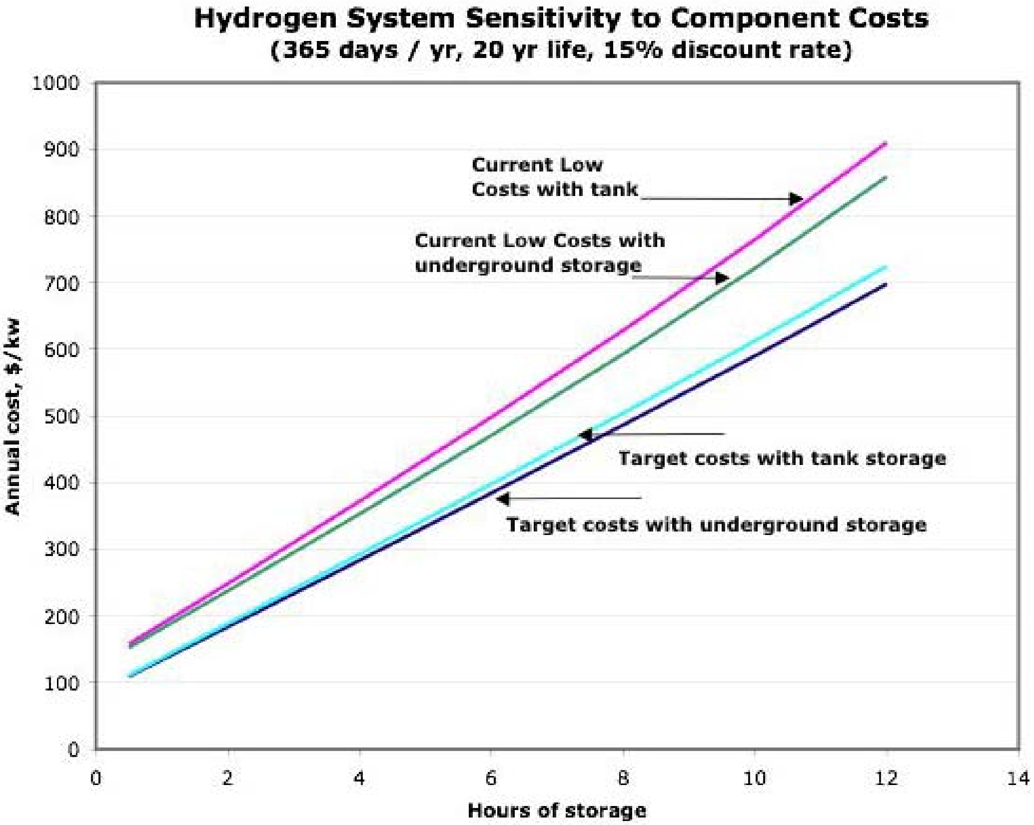


Figure 6. Hydrogen system annual cost sensitivity to storage component costs.

4 Base case results and sensitivity analysis

This section of the report presents the foundational case for the analysis and comparison of energy storage technologies used in a generic load-leveling application with low off-peak costs for charging electricity. The results are presented as annual cost for each technology for a range of storage sizes. From this base case, a sensitivity analysis is performed for the hydrogen system with a variety of cost assumptions and economic and operational scenarios. The most competitive alternative is Compressed Air Energy Storage (CAES), which is compared in more detail.

The analysis of the Spilled Wind business case is presented in Section 5.

4.1 Base case

In the base case, the alternative energy storage technologies presented previously (i.e., three types of batteries, underground (conventional) CAES, and pumped hydro) are compared first with hydrogen systems using current lows cost and performance values, and second with hydrogen systems using DOE target values for cost and performance. The “current” hydrogen system assumes compressed gas storage. The “target” values assume bulk storage in geologic formations. The battery technologies considered are advanced lead-acid batteries (suitable for daily cycling), sodium-sulfur batteries (designed for optimum storage of 6 to 8 hours), and flow batteries (also designed for “bulk” storage). There are a number of flow batteries on the market. The values used here are most representative of zinc-bromine batteries, but are similar to values for vanadium redox batteries. All the technologies will require maintenance, which is included in the cost stream. The batteries and hydrogen systems will also require period replacement of components and these are accounted for in the analysis.

Economic and use assumptions

Table 3 lists the economic and operational assumptions for the base case.

Table 3. Economic and operational assumptions for the base case.

System lifetime	20 years
Capital charge rate	15%
Discount rate	10%
Inflation rate	2%
Days of operation per year	365
Cost of electricity	5 ⊄ / kWh
Cost of natural gas	5 $/ BTU

Energy storage technology costs

The capital cost, replacement cost, and efficiency assumptions for the alternative energy storage technologies are included in Table 4. The values for alternative technologies are drawn from Reference [10]. The number of cycles is converted to replacement life-time in the analysis.

Table 4. Cost and performance assumptions for energy storage technologies.

Technology	**Power Subsystem Cost $/kW**	**Energy Storage Subsystem Cost $/kWh**	**Round-trip Efficiency %**	**Cycles**
Advanced Lead-acid Batteries (2000 cycle life)	400	330	80	2,000
Sodium/sulfur Batteries	350	350	75	3,000
Flow Batteries	400	400	70	3,000
CAES	700	5	N/A (70)	25,000
Pumped hydro	1,200	75	85	25,000

Sizing the system

In the results shown below in the next section, the system is sized for delivering stored energy in hours at maximum output power, taking into account the inefficiencies of the charging and discharging systems. The charging and discharging components are sized for the same maximum charging and discharging rates, again taking into account the inefficiencies of both the charging and discharging devices. The cost model could be revised to store more than the minimum amount of energy, but currently this is not the case. Similarly, the charging and discharging subsystems could be sized for different rates, if they are separate pieces, but currently the model does not size for different rates. As an example, the fuel cell in the hydrogen system could be down-sized to generate over a longer period of time than the electrolyzer is sized for charging. This would reduce the capital cost of the fuel cell system. Thus the results shown here represent a conservative cost estimate.

Annual cost comparison for base case

A life-cycle cost analysis was performed for each technology at each size point. These are presented first as annual costs in the figure below. Some things to note: for bulk storage in the range of 4 to 8 hours, CAES is shown to be the least expensive option; assuming suitable geologic siting is available. The hydrogen system at DOE target costs is competitive with CAES and pumped hydro. Battery systems become expensive beyond about 2 to 3 hours because the storage is expensive, and for a 20-year life there are numerous replacements.

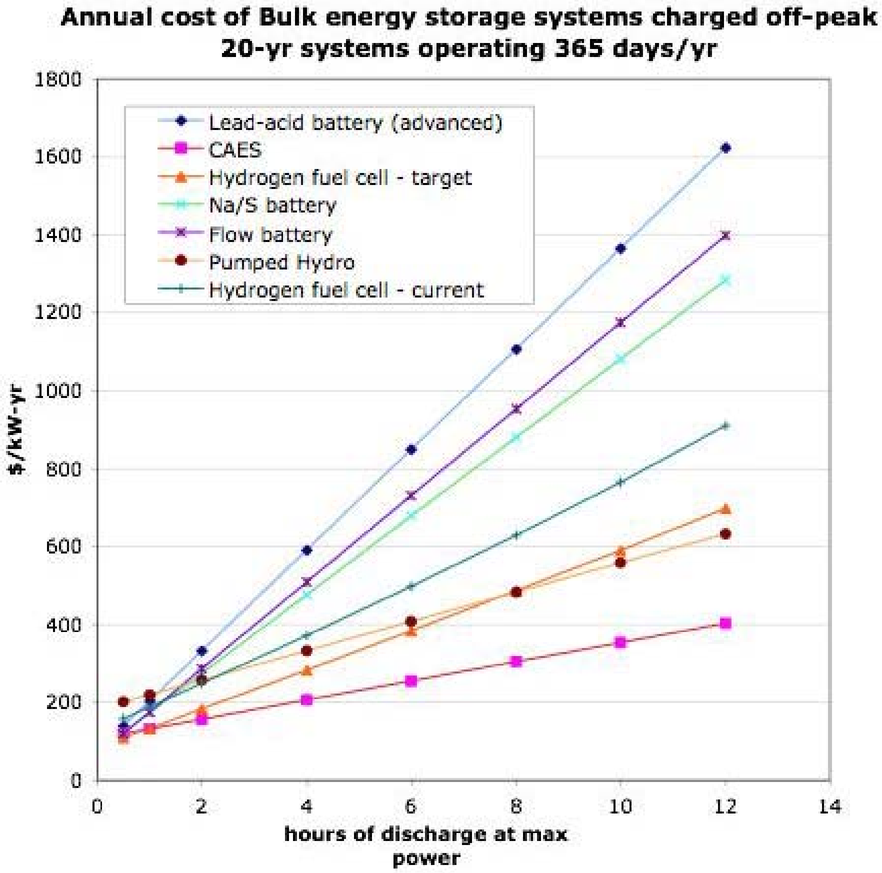


Figure 7. Annual cost results for the base case.

4.2 Parametric sensitivity for hydrogen

The following parameters are varied to determine sensitivity for hydrogen configurations and utilization scenarios.

- Days of operation per year: 250 instead of 365. (Discharging is more likely to be fewer days than charging, but the charging system can be derated if it can be charged over the weekend.)
- Capital charge rate
- Replacing target geologic storage costs with cryotank gas storage costs

Preliminary results are shown in Figure 8 below, with a CAES comparison. The variation in results is pretty dramatic, so it is important to be consistent in selecting parameters for comparison of technologies and scenarios.

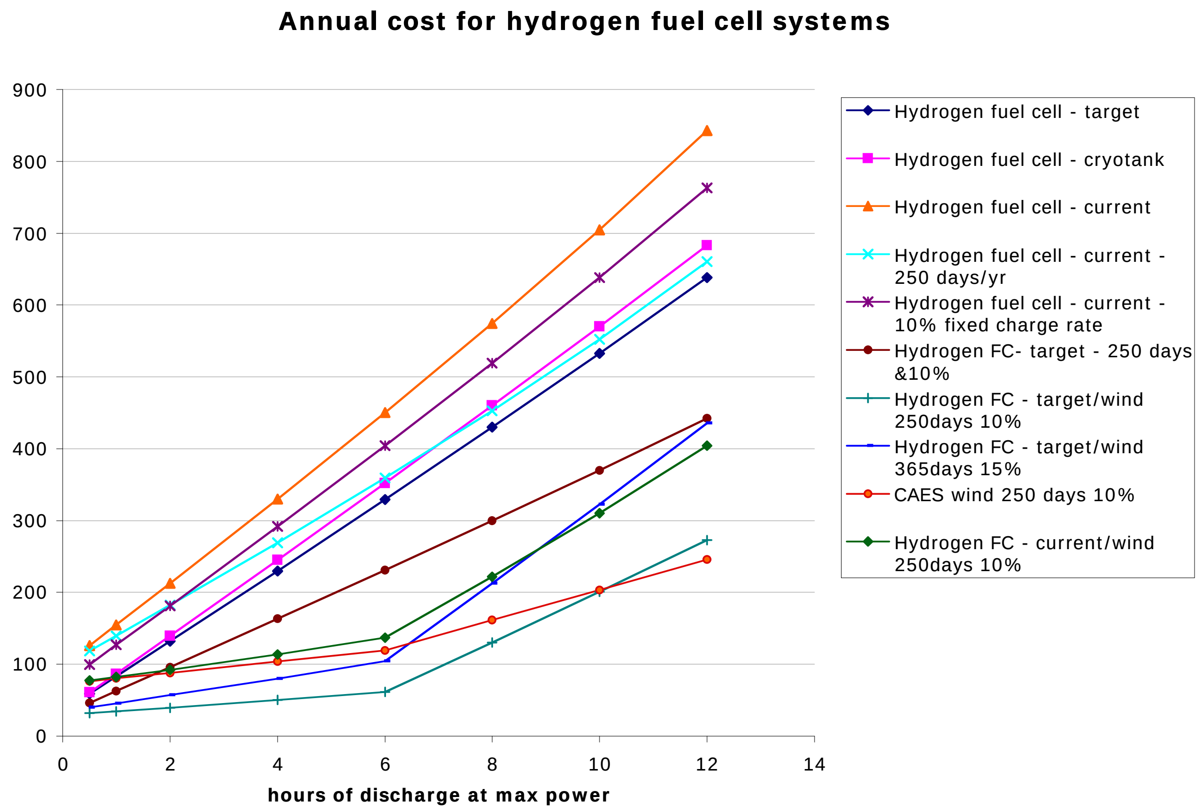


Figure 8. Sensitivity analysis / parameter study for hydrogen system costs.

5 The case of spilled or curtailed wind

5.1 Spilled / curtailed wind in the US

Significant numbers of wind turbines have been built in the US in the past few years, some in response to tax incentives, and more recently to meet the objectives of renewable portfolio standards. [17,18]

One problem with wind power is that the output can vary substantially with time – from minute to minute, day to day, and seasonally. It can also vary from predictions, and be unsteady even during the most “constant” conditions. Finally, wind resources are often located far from the loads they serve.

Figure 9 shows a snapshot of wind generation in California, illustrating how the peak wind generation is out of sync with peak load. [19] Several impacts to the rest of the grid include the possible need to turn down base load at night if wind power is to be accepted on the grid, and the possible need to install additional peaking power for the afternoon load if the wind that was expected does not occur.

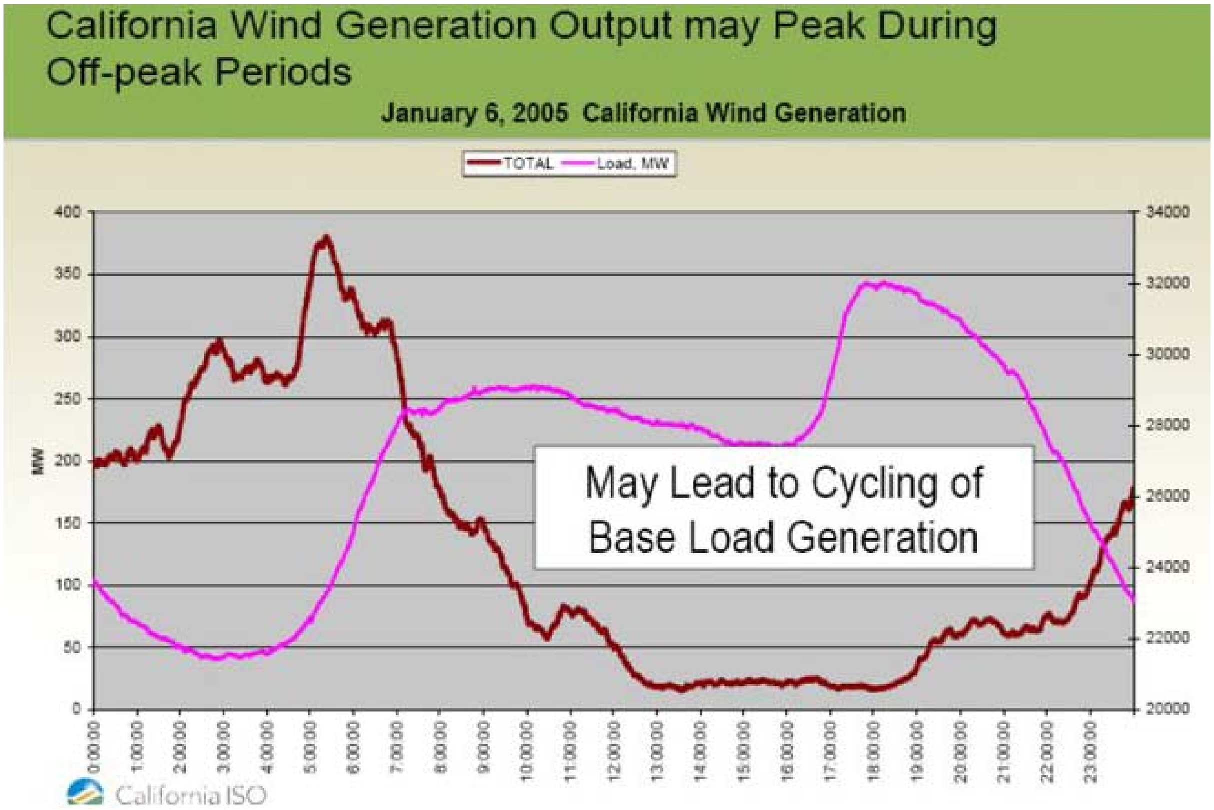


Figure 9. California wind generation peaks at night [17].

The wind power industry is reluctant to say that there is a need for energy storage to accompany wind power because of the additional cost, but in some cases, energy storage is the ideal complement to wind.

One such case is the extreme case of curtailed wind. In some locations, when power from wind generators is not needed to meet load, the wind company will either idle the turbines or "spill" the power produced. (The terminology comes from the hydro power industry where excess stored water can be spilled from a reservoir if not needed.) In the most extreme case, a wind producer will be charged for putting power on the grid when it is not needed. In fact, Texas producers can show negative cost for their wind power beginning in 2009, as indicated in Figure 10. [20] The number of hours of excess wind is shown in Figure 11.

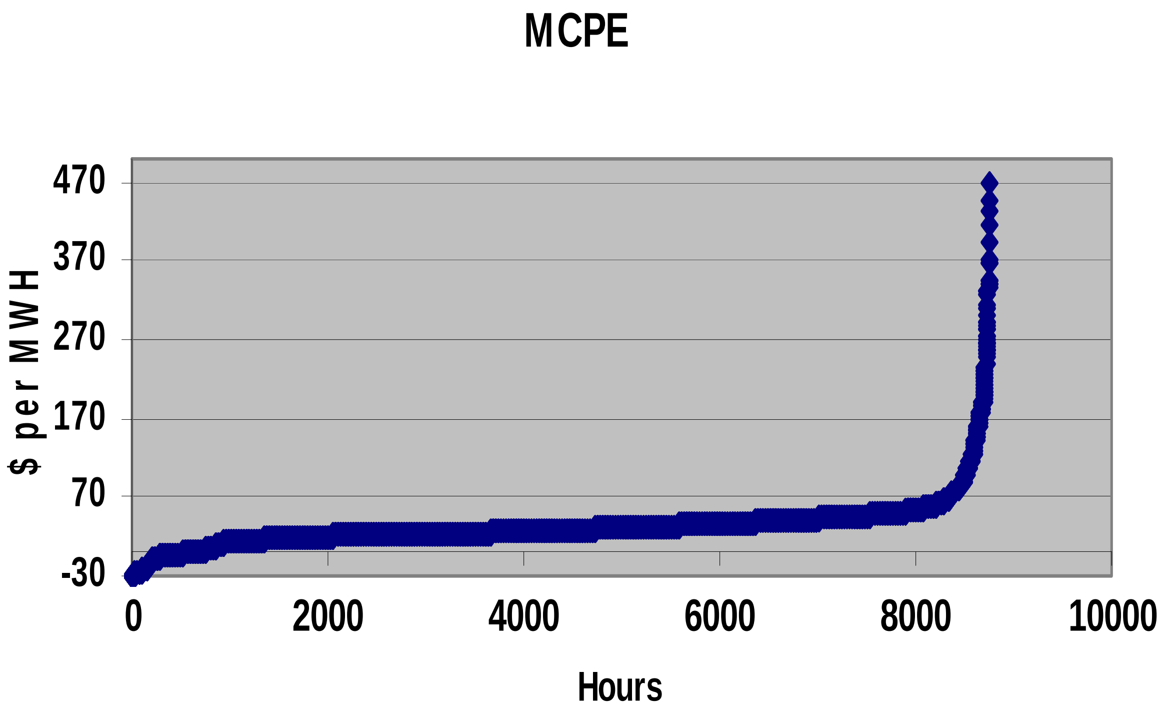


Figure 10. Price paid for wind power – ERCOT 2009 [20].

This is an ideal situation for energy storage. Charging the storage system for free and eliminates all operating costs resulting from the inefficiency of the electrolyzer AND the fuel cell. The electrolyzer still must be sized to fill the storage with enough hydrogen for the discharge and fuel cell operation, but there is no electric penalty.

In modeling this case, the electricity used to charge the storage system (i.e., run the electrolyzer) is free up to six hours, assuming it would otherwise be wasted (curtailed or spilled).

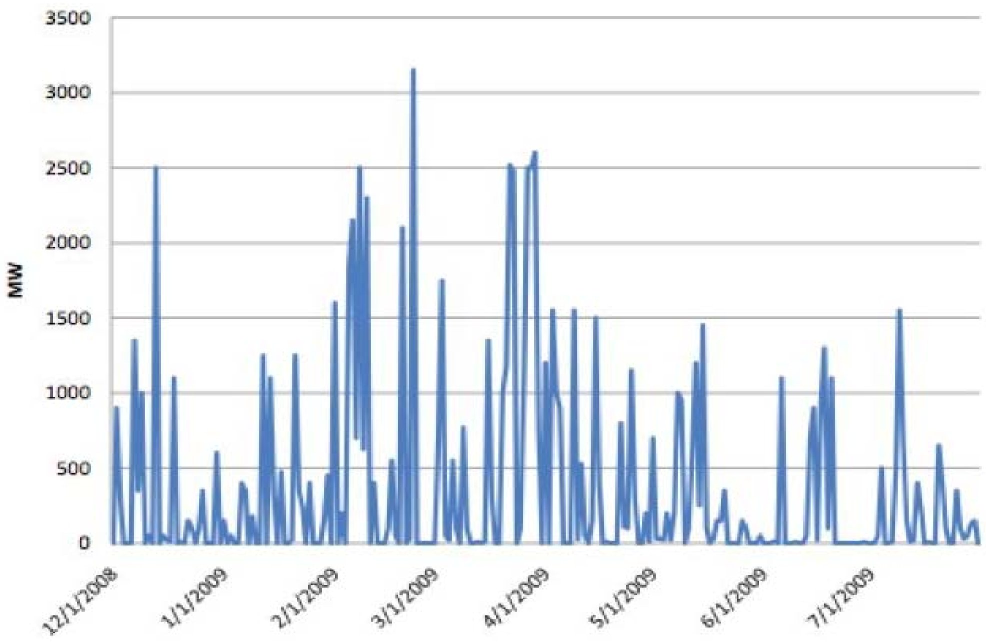


Figure 11. Hours of excess wind in West Texas [20].

5.2 Analysis for the case of spilled wind

The case of spilled wind is established as the business case for this study. Based on conversations with a number of utility operators, a suitable time frame for charging energy storage from wind is 6 hours [21,22]. The realistic power level is 50 MW, resulting in a storage capacity of 300 MWh. For the analysis is this study, the results are all presented on a per-kW basis, but based on an underlying assumption of technologies that can scale to adequate size.

The economic and operating assumptions for the analysis of the business case are listed in Table 5.

Table 5. Business case economic and operational parameters.

Storage charging	6 hours
Storage discharging	Min 6 hrs
Cost of charging electricity	0.00 $ / kWh for 6 hrs
Cost of charging electricity	0.05 $ / kWh thereafter
Days of operation per year	365
Cost of natural gas (for CAES)	5 $/ BTU
Storage charging	6 hours

Annual cost comparison for the case of spilled wind

Figure 12 shows the components of the annualized cost for the hydrogen energy storage system for four cases: 1) the base case (load-leveling) with current/low cost components, 2) the base case with target costs, 3) the business case of spilled wind with current / low cost components and 4) the case of spilled wind with target cost components. The target case assumes hydrogen storage in an underground reservoir, i.e., the "best" case. However, as discussed in Section 3, the storage selection at 6 hours has a minimal impact on the overall system cost. The large electricity cost component (due to the inefficiency of the system) is eliminated if the "spilled" wind power can be used free of charge. This is the basis of the business case.

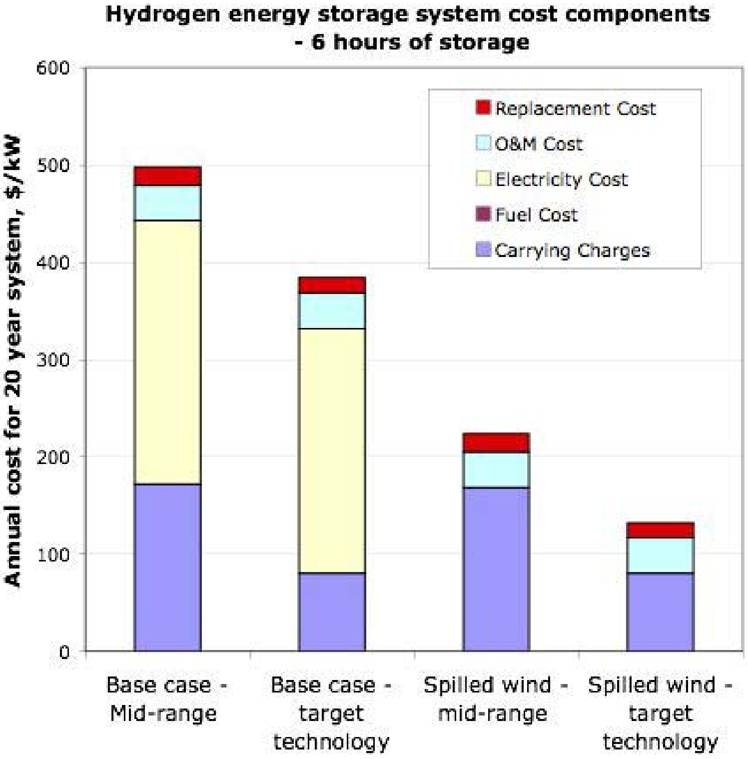


Figure 12. Annual cost components for hydrogen storage systems.

Figure 13 below shows the impact of free charging energy up 6 hours. All of the technologies benefit, but the hydrogen system benefits especially because the inefficiency of the system is partially removed from the equation. In this case, even the hydrogen system at current costs can be competitive.

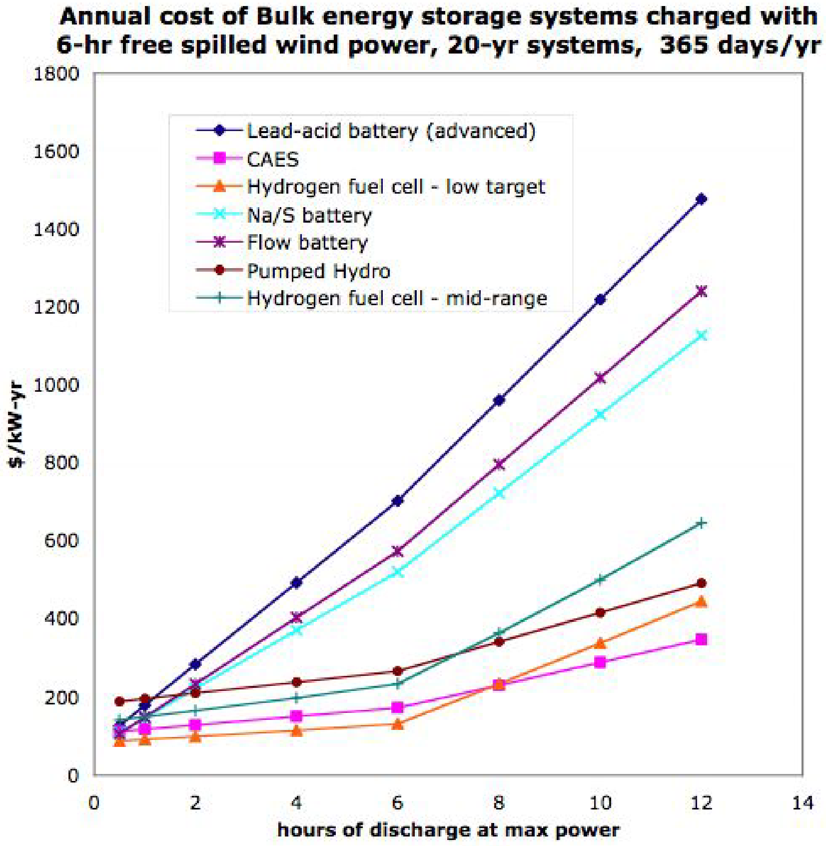


Figure 13. Annual cost results for the case of spilled wind.

6 Present value analysis of costs and benefits for hydrogen systems

The annual costs can be converted to present values by summing the discounted values over 20 years.

$$PV = F_0 / (1 + i)^0 + F_1 / (1 + i)^1 + F_2 /(1 + i)^2 + ... + F_n /(1 + i)^n$$

where

PV = present worth or value

F = future cash flow

n = number of years

i = discount rate

$(1 + i)^n$ is known as the "compound amount factor."

For a 10% discount rate and 20 years, the present worth factor is 6.7275.

Table 6. Assumptions for the present value analysis.

System lifetime	20 years
Capital charge rate	15%
Discount rate	10%
Inflation rate	2%

6.1 Present value of costs

Present value of costs for bulk hydrogen systems with 6 hours of storage are shown in Figure 14 for the base case with current technology and target technology, and for the case of spilled wind (i.e., free charging electricity) for both current and target technology. The 6-hr storage case is optimum if there are 6 hours of free charging electricity.

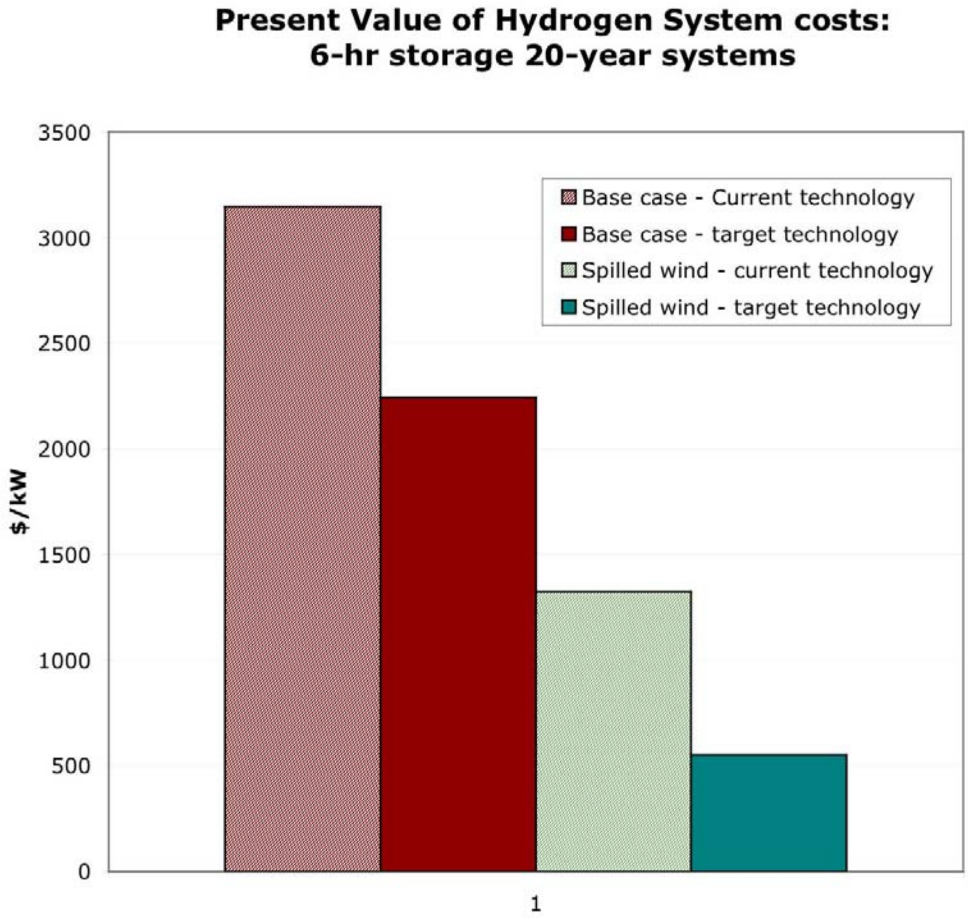


Figure 14. Present value of hydrogen system costs – 6 hours of storage.

6.2 Present value of benefits

The present value of estimated benefits ranges quite broadly for the various studies found in the literature. In the most recent Sandia report by Eyer and Corey [23], the value for wind energy time shift is estimated at $54/kW-yr. The installed capacity provides an additional benefit of approximately $120/kW-yr. Overlaying the 20-year present value of these benefits on the present value of costs, as shown in Figure 15, indicates a potential opportunity for hydrogen if additive benefits can be achieved, low charging costs are available, and systems costs reach targets.

Cost and benefit analysis have been presented up to this point on a $/kW basis. This has been typical over the last decade, as utilities compare energy storage with energy generation technologies. Recently, however, EPRI [24] has published benefits estimates on a $/kWh basis, which makes it easier to compare various energy storage technologies with each other. On the basis of $/kWh, the benefits of renewables integration, added to the benefits of capacity credit, are shown in Figure 16. On this basis, the benefit / cost ratio looks even more attractive for the case of spilled wind, or even for the case of load leveling if system costs should reach target levels.

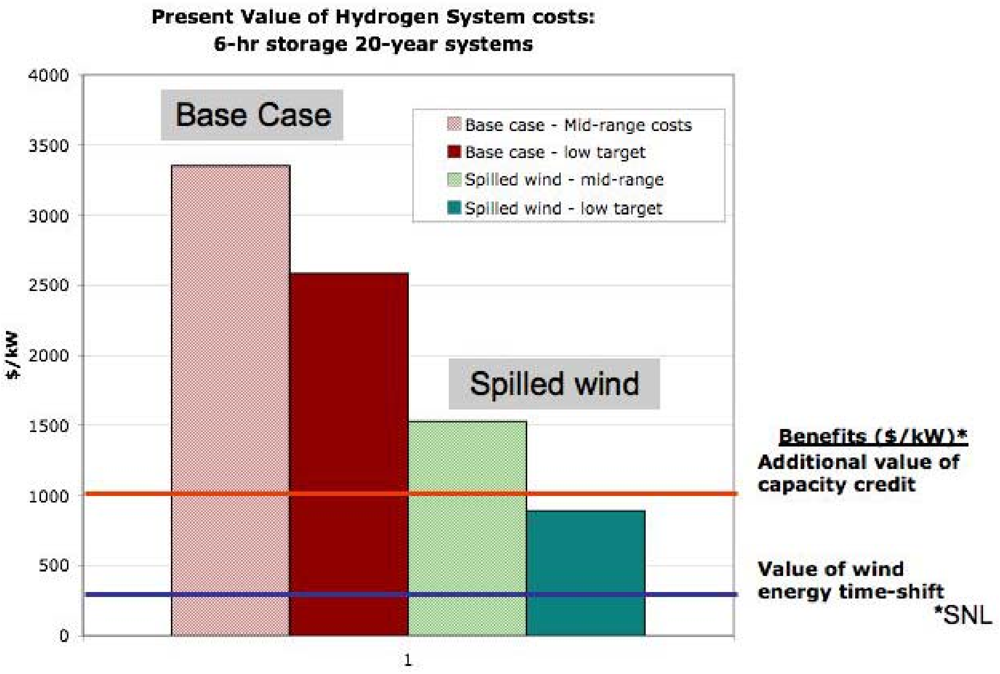


Figure 15. Present value of costs and benefits for hydrogen systems on a $/kW basis.

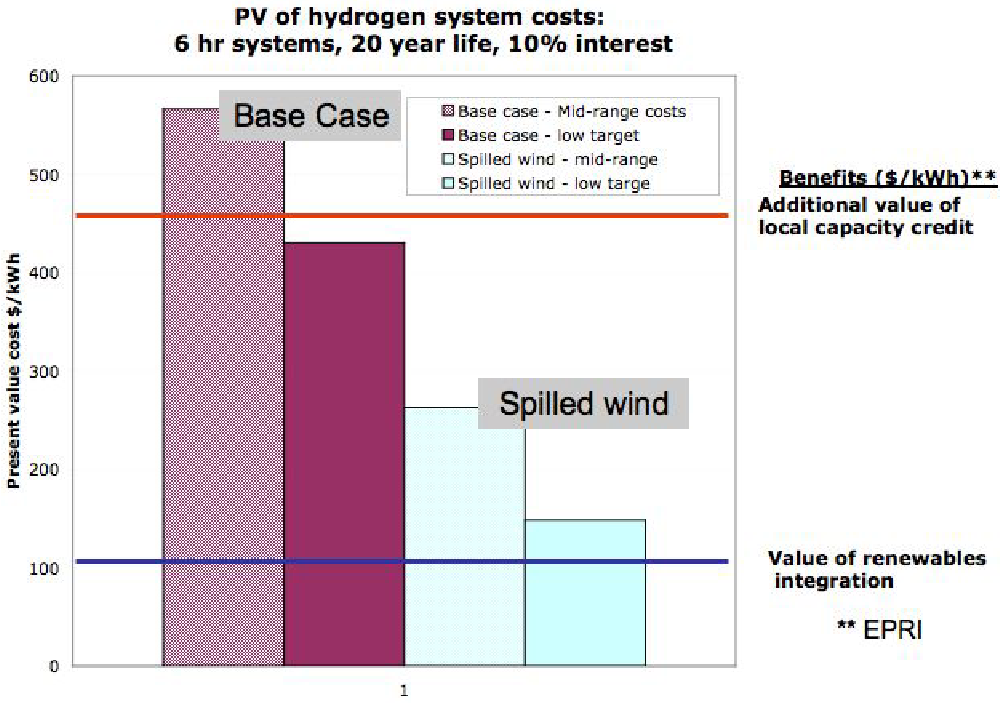


Figure 16. Present value of costs and benefits for hydrogen systems on $/kWh basis.

7 Business discussions

This study has presented a potential business opportunity for electric systems with substantial wind power, especially where it is out of sync with the system load. Discussions were held with industry personnel in several states to discuss the potential for demonstration of a hydrogen energy storage system in this application. Highlights of these discussions follow.

Colorado

XCel Energy of Colorado has been a supporter of the combination of energy storage with wind power for a number of years. They have participated in NREL demonstrations of battery and wind power [25], and are now participating in projects to connect renewables, both wind and solar, to hydrogen electrolysis systems [26]. XCel Energy co-sponsored a workshop on "Renewable Hydrogen" in 2009 and participates in the DOE Hydrogen Technical Advisory Group. Personnel from XCel Energy have provided insight into this study.

Texas

Austin Energy personnel have been considering large-scale energy storage for buffering wind produced in West Texas for transmission to load centers in other parts of Texas. As indicated in Section 5, there exists considerable mismatch in Texas, in part due to tax incentives to build wind. Discussions and information from Austin Energy have been very useful to this study.

California

California has recently instituted a Renewable Portfolio Standard calling for 30% of power used in the state to come from renewable sources. [19] A large fraction comes from wind, which blows off-peak. A CAES plant in central California is being built to capture some of this wind. [27] A hydrogen energy storage system could function in a similar fashion. A discussion with the CIEE has been initiated. [28]

Hawaii

Nowhere in the US is renewable energy from local sources more important than Hawaii, which otherwise imports all fossil fuel energy. Wind farms have sprouted everywhere in Hawaii, along with solar installations. Unfortunately, the individual island grids cannot operate properly with so much unscheduled generation. As a result, new utility requirements state that new renewable sources must be "firm and dispatchable."[29] This presents an ideal case for the combination of energy storage and wind or solar, which is now being implemented. [30] Business discussions are underway with industry on the island of Maui to propose a hydrogen energy system demonstration to optimize the output of local wind plants.

8 Conclusions and recommended further work

Some conclusions from this study include the following:

- Hydrogen energy storage is an ideal match for renewables of all scales, especially large-scale wind.
- Hydrogen with renewables is effective for reducing green house gases from power generation.
- Underground storage offers opportunities to store H_2 because of large capacity and competitive cost.
- Stationary hydrogen and fuel cell applications complement the electric system across a spectrum of sizes:
  - Residential and communities
  - Distributed generation
  - Load and source - leveling
- Market opportunities need development.

Not discussed in this report, but also true

- H_2 produced by electrolysis from renewable energy can also supply fuel for transportation.

Recommendations for further work include:

- Add **scaling** considerations to utility business model, considering the spectrum of value propositions, both at much large scale of storage, and smaller scale of storage.
- Add **location** considerations to cost and benefit analysis.
- Build **third-party** (non-utility) opportunities into business model.
- Continue discussions and deliberations with **commercial** interests regarding market potential.

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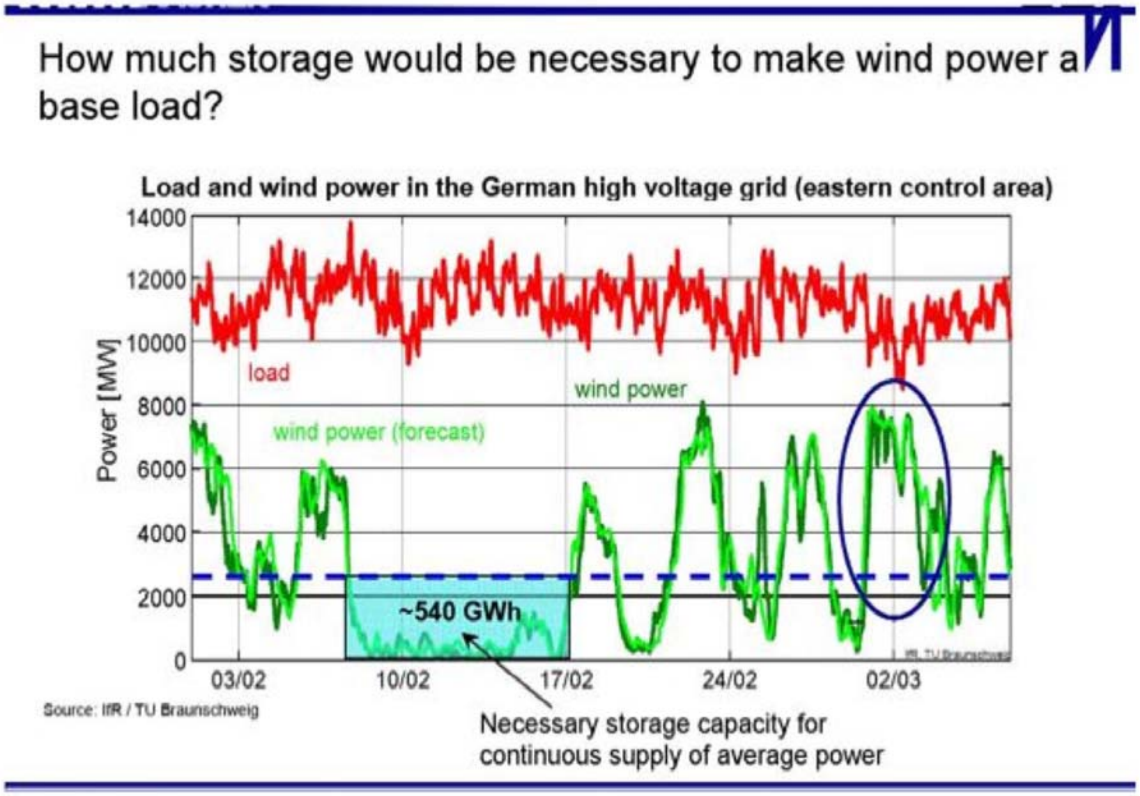
Appendix: Background materials

While the concept of using hydrogen for large-scale energy storage has been under consideration for over a decade,[1,2] recent attention from Europe has raised new discussion of the potential application to buffer large-scale intermittent wind. One of the most prominent studies, completed in Germany in 2008 by VDE, contains the four charts shown below. Figures A1 through A3[3] indicate the need for large storage to buffer wind, the concept for storing hydrogen in salt caverns, and the suitable regime for hydrogen storage compared to other applications. The final chart (Figure A4[4]) presents the estimated costs of large-scale technologies - pumped hydro, CAES and hydrogen – as estimated in the VDE study.



How much storage would be necessary to make wind power a base load?

Load and wind power in the German high voltage grid (eastern control area)

Source: IfR / TU Braunschweig

Necessary storage capacity for continuous supply of average power

Figure A1. Load and wind power in the German high voltage grid.

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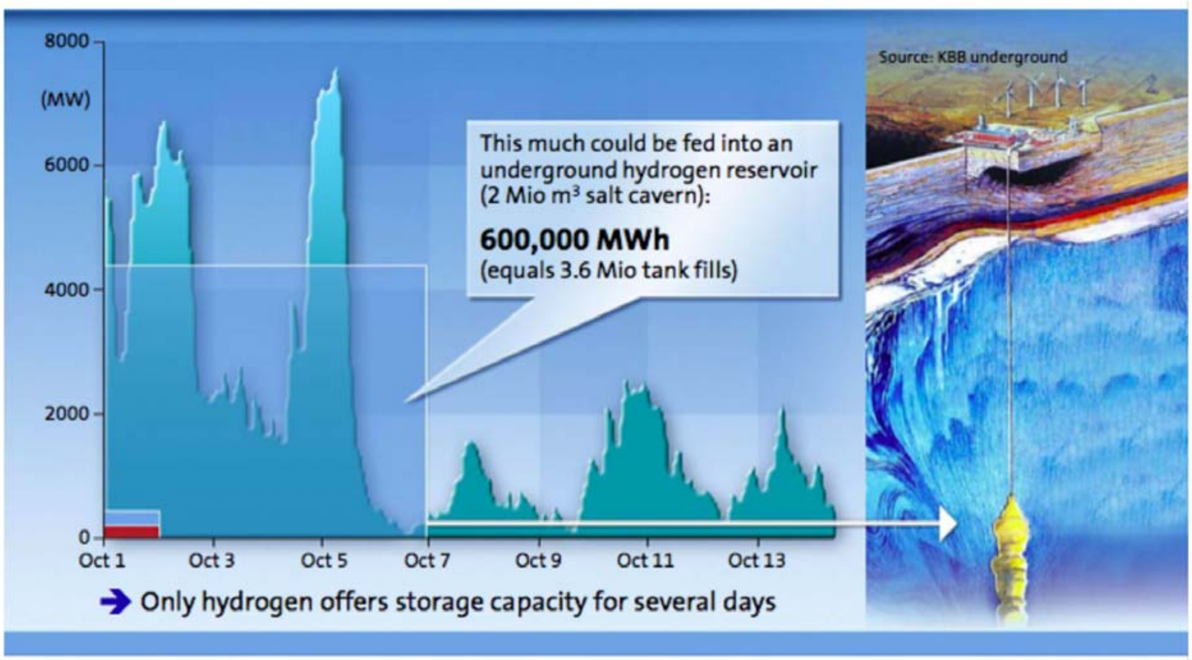

Source: KBB underground

This much could be fed into an underground hydrogen reservoir (2 Mio m³ salt cavern):

600,000 MWh

(equals 3.6 Mio tank fills)

➔ Only hydrogen offers storage capacity for several days

Figure A2. German concept for storing huge volumes of hydrogen in salt caverns: “The energy buffer in the renewable energy system.”

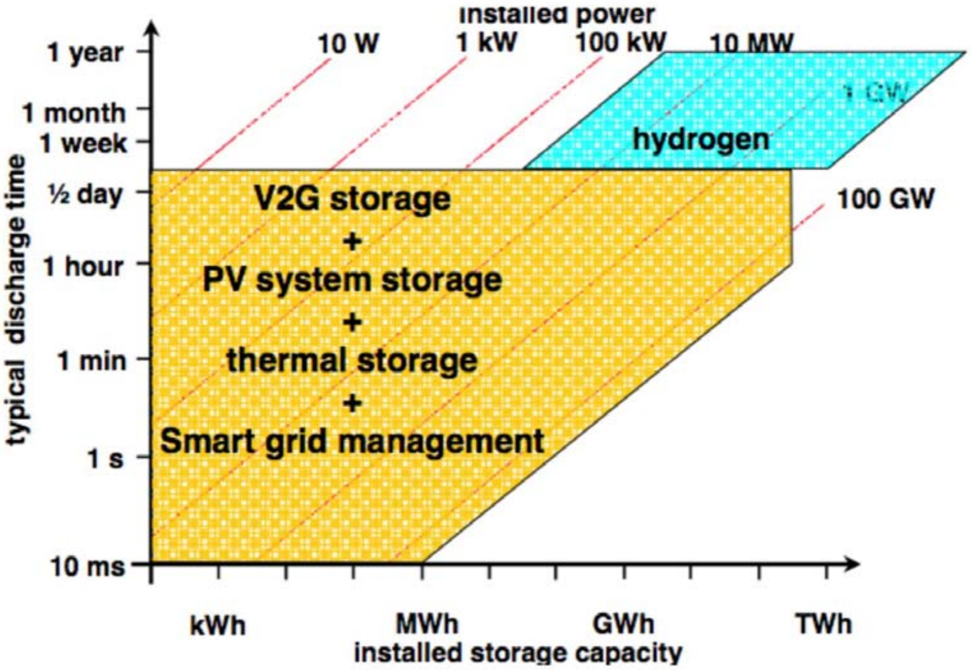

Figure A3. German study results show suitable range and application for hydrogen storage.

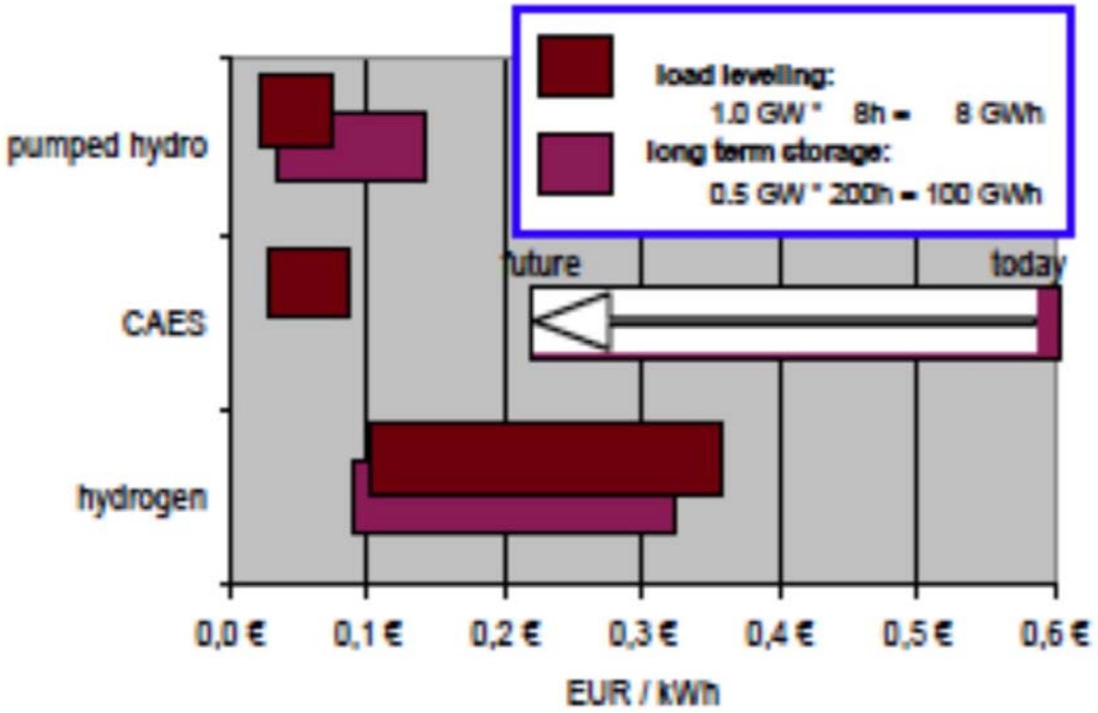

Figure A4. Estimated costs of electricity from systems with large-scale storage.

Several electrolyzer and fuel cell companies have also recently begun to promote the use of hydrogen in bulk storage to complement large-scale renewables. The chart in Figure A5 shows the approach that the Canadian company Hydrogenics is taking to move hydrogen energy storage into the energy storage debate.[5]

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[5] Harris, Kevin, Hydrogenics, *Hydrogen Energy Storage and Renewables*, presented at the National Hydrogen Association Annual meeting, May 2010.

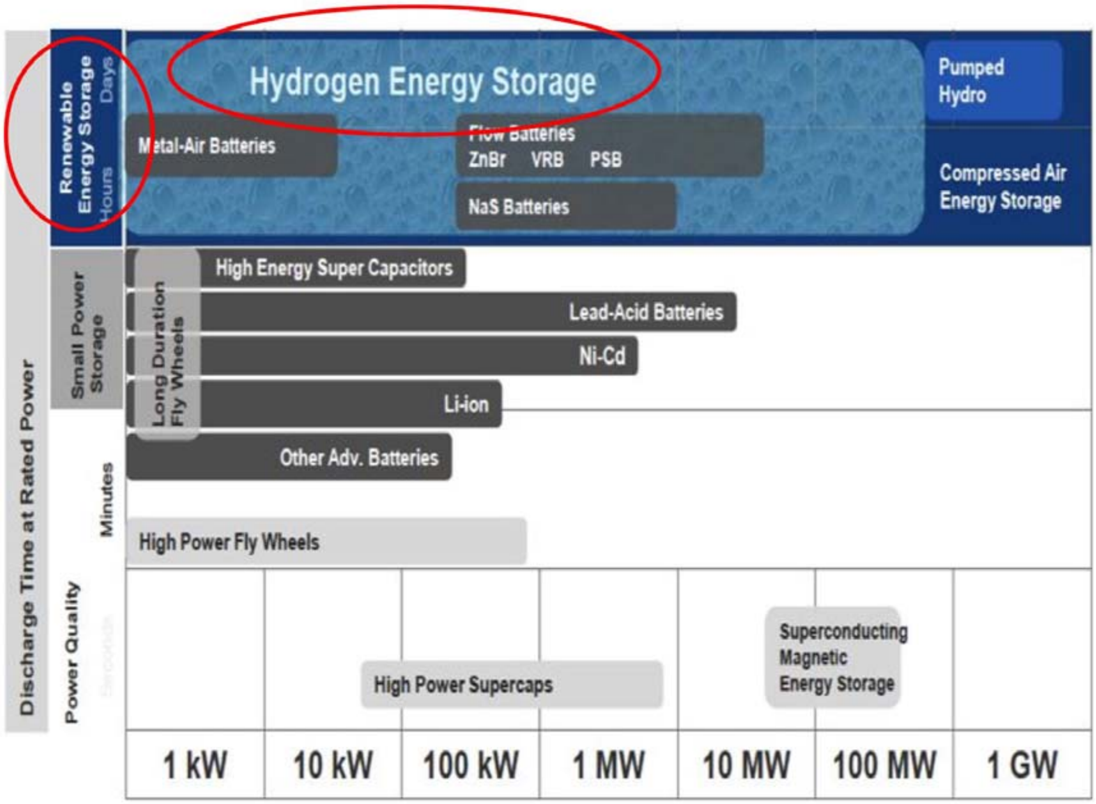

Figure A5. Hydrogen energy storage applications – the view from Hydrogenics presents a broader spectrum of use.

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