Analysis of Hydrogen and Competing Technologies for Utility-Scale Energy Storage

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Project Overview

Presentation based on:

Lifecycle Cost Analysis of Hydrogen Versus Other Technologies for Electrical Energy Storage
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National Renewable Energy Laboratory, Golden, CO
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Collaborations and Reviewers
- NREL Hydrogen Technologies & Systems Center
- NREL Strategic Energy Analysis Center
- NREL Systems Engineering & Program Integration Office
- Pacific Northwest National Laboratory
- Xcel Energy & the Hydrogen Utility Group
Outline

Energy Storage Scenario and Analysis Framework

Technologies

Analysis Results

Conclusions
The Potential Value of Energy Storage

Make variable and unpredictable renewable resources dispatchable by:

- Reducing transmission costs for remote wind resources
- Taking advantage of arbitrage opportunities
- Allowing “baseloading” with renewable resources
- Providing grid services such as spinning reserve

Energy Arbitrage—The Focus of This Analysis

Objective
Evaluate the economic viability of using hydrogen for utility-scale energy storage applications in comparison with other electricity storage technologies

Study Framework
Basic energy arbitrage economic analysis
- Lifecycle costs including initial investment, operating costs, and future replacement costs
- Results presented as levelized cost of delivered energy ($/kWh)

Benchmark against competing technologies on an “apples to apples” basis
- Batteries
- Pumped hydro
- Compressed air energy storage
Energy Storage Scenario

Nominal storage volume is 300 MWh (50 MW, 6 hours)
  - Electricity is produced from the storage system during 6 peak hours (1 to 7 pm) on weekdays
  - Electricity is purchased during off-peak hours to charge the system

Electricity source: excess wind/off-peak grid electricity
  - Assumed steady and unlimited supply during off-peak hours (18 hours on weekdays and 24 hours on weekends)
  - Assumed fixed purchase price of off-peak/renewable electricity

Source: HOMER model output
Analysis Framework and Assumptions

Major Assumptions
- The storage system is not large enough to affect grid peak or off-peak electricity prices
- No taxes or transmission charges are included in the analysis
- The supply of off-peak and/or renewable electricity is unlimited
- Costs are presented in $2008

Timeframes
- High cost or “current” technology
- Mid-range cost
  - Some installations exist
  - Some cost reductions for bulk manufacturing and system integration have been realized
  - Installations are assumed in the near future: 3 to 5 years
- Low-range cost
  - Estimates for fully mature technologies and facility experience

Cost Analysis Performed Using the HOMER Model
- Distributed power cost optimization model for conventional and renewable energy technologies
- Results are presented as levelized cost of energy: $/kWh or $/kg for hydrogen
Study Framework—Facility Life Economic Analysis

Financial Assumptions

- 40-year plant life (Some equipment will be replaced at more frequent intervals.)
- 10% after-tax internal rate of return
- 100% equity financing

Cost Assumptions

- Electricity is purchased from the grid during off-peak hours at 3.8¢/kWh (base case); sensitivity cases at 2.5¢/kWh and 6¢/kWh
- Natural gas is purchased at $7/mmBtu (base case); sensitivity cases at $5/mmBtu and $9/mmBtu for the CAES system
Hydrogen for Energy Storage

Concept:

Two scenarios of production of excess hydrogen for vehicle use:
- “Slipstream” of about 1,400 kg additional hydrogen per day from aboveground storage tanks (5 tanker trucks per day)
- 500 kg/h (12,000 kg/day) additional hydrogen continuously fed to a pipeline

Electrolyzer is only run during off-peak hours.
Hydrogen Scenarios—Major Assumptions

Major Assumptions

- Electrolyzer performance and cost based on alkaline electrolyzers operated at 435 psi, 80°C.
- Polymer electrolyte membrane (PEM) air cooled fuel cell operated at ~ 30 psi.
- Hydrogen storage in aboveground steel tanks or geologic storage.
  - Hydrogen storage losses assumed minimal.
  - Compression energy not recovered.
- Hydrogen delivery and dispensing not included in the analysis of excess hydrogen for vehicles.
Batteries, Pumped Hydro, & CAES—Major Assumptions

Major Assumptions

- Power conversion system for battery round-trip efficiency is 90%.
- Pumped hydro and CAES systems do not require separate power conversion system.
- For compressed air storage systems, compression heat is not stored. Air from the storage system is heated with turbine exhaust gas.
Hydrogen is competitive with batteries and could be competitive with CAES and pumped hydro in locations that are not favorable for these technologies.
Hydrogen Energy Storage System with Excess Hydrogen—NPC

Five tankers of excess hydrogen per day (1,400 kg/day)
- Electrolyzer and hydrogen tank slightly larger for the excess hydrogen case than for the case without excess hydrogen
- Hydrogen LCOE of $4.69/kg (not including tanker truck transport and dispensing)
- Compares to ~$4 for production portion of electrolysis forecourt station
Hydrogen Energy Storage System with Excess Hydrogen—NPC

- **500 kg/h of excess hydrogen (12,000 kg/day)**
  - Electrolyzer approximately doubled in size in comparison to the case without excess hydrogen
  - Hydrogen LCOE of $3.33/kg (not including tanker truck transport and dispensing)
  - Compares to ~$7 for electrolysis at a central production facility of the same size
Hydrogen Systems Cost Analysis

Electrolyzers and Storage—Cost values and projections based on H2A case studies and DOE technical and cost targets

PEM Fuel Cell—Cost values and projections based on literature review and DOE technical and cost targets

![Graph showing cost and performance values and projections for PEM fuel cells]

Hydrogen Fueled Gas Turbine—Cost and performance values and projections based on literature review

- High-efficiency gas turbine combusts pure oxygen and hydrogen in a combustion chamber to produce high-temperature steam, which drives a steam turbine.
  - Efficiency = 70% (Pilavachi et al. 2009)
- Oxygen is assumed to be collected from the electrolyzer.
Battery Cost Analysis

Batteries

**Nickel Cadmium**
- 2003 peak power in Fairbanks Alaska (26 MW, 1/2h)

**Sodium Sulfur**
- Several projects for Tokyo Electric Power (up to 6 MW, 48 MWh)

**Vanadium Redox**
- 2005 peak power in Hokkaido Japan (4 MW, 1.5h)
- 2004 voltage-stabilization project in Castle Valley Utah (250 kW, 8h)
- 2003 load-shifting application in Currie Tasmania (200 kW, 4h)
- 2001 wind stabilization in Hokkaido Japan (170 kW, 6h)

Compressed Air & Pumped Hydro Cost Analysis

Compressed Air Energy Storage

- 1991 peak power in McIntosh Alabama (110 MW, 26h)
- 1978 Huntorf Germany (290 MW spinning reserve)

Pumped Hydro

- Many installations, earliest in the U.S. in 1929; current capacity about 19,000 MW

Round-Trip Efficiency and Electricity Price Sensitivity

Electricity price sensitivity

- Low-capital-cost, high-efficiency pumped hydro system is sensitive to electricity price
- High-capital-cost NiCd system is insensitive to electricity price
- For other storage systems, sensitivity to electricity price is roughly inversely proportional to round-trip efficiency
Cost Implications for Hydrogen Systems

Costs could be reduced by increasing the round-trip efficiency.

- Fuel cell efficiency has a bigger impact on LCOE than electrolyzer efficiency.
  - ~ 0.5% change in LCOE per percent change in fuel cell efficiency
  - ~ 0.2% change in LCOE per percent change in electrolyzer efficiency

Cost could be reduced if a reversible fuel cell with higher round-trip efficiency were developed.
Conclusions

Hydrogen is competitive with battery technologies for this application and could be competitive with CAES and pumped hydro in locations that are not favorable for these technologies.

Excess hydrogen could be produced for the transportation market.

Hydrogen has several important advantages over competing technologies, including:

- Hydrogen has very high storage energy density (170 kWh/m3 vs. 2.4 for CAES and 0.7 for pumped hydro).
  - Allows for potential economic viability of aboveground storage
  - Hydrogen could be co-fired in a combustion turbine with natural gas to provide additional flexibility for the storage system.

The major disadvantage of hydrogen energy storage is cost.

- Research and deployment of electrolyzers and fuel cells may reduce cost significantly.
Thank You

Questions?
Capital cost reductions for the fuel cell drive decrease in NPC.

Increased stack durability decreases expected replacement costs.
LCOE sensitivity to capital cost in proportion to other costs decreases from the high-cost case to the low-cost case.

High sensitivity to the cost of electricity due to relatively low round-trip efficiency (28% – 41%)
Hydrogen Fuel Cell with Aboveground Storage—Sensitivity

More tanks are required for the high-cost case because of the low efficiency of the fuel cell.

Aboveground storage adds 6% – 18% to the LCOE.
Hydrogen gas turbine with geologic storage is proportionally more sensitive to electricity cost because of its relatively low capital cost and low round-trip efficiency.
NPC for nickel cadmium battery systems is high due to high capital cost.
The LCOE of Nickel cadmium battery systems is most sensitive to capital cost.
Sodium sulfur battery systems have lower capital and replacement costs than NiCd batteries.
Sodium sulfur battery systems are more sensitive to electricity price than NiCd batteries.
Electrolyte has a high initial capital cost but is assumed to last the entire lifespan of the facility.
Electrolyte cost was varied ± 50% due to historical volatility in vanadium prices. VR battery LCOE is most sensitive to the cost of the electrolyte.
Pumped hydro systems have relatively low capital cost and very low maintenance costs in comparison to hydrogen and battery systems.
Pumped hydro systems are relatively sensitive to electricity price because electricity is a relatively large fraction of the overall yearly cost.
Approximately 1/3 of the output energy from the CAES systems is derived from natural gas. Approximately 2/3 of the energy is supplied by stored compressed air.
CAES—Sensitivity

LOW-COST CASE
- Electricity price: $0.08
- Natural gas price
- Compressor/combustion turbine capital cost
- Fixed O&M
- Cavern capital cost

MID-RANGE CASE
- Electricity price
- Natural gas price
- Compressor/combustion turbine capital cost
- Fixed O&M
- Cavern capital cost

HIGH-COST CASE
- Electricity price
- Natural gas price
- Compressor/combustion turbine capital cost
- Fixed O&M
- Cavern capital cost

Assumed aboveground storage for the mid-range case to provide comparison to hydrogen system.
## Backup Slides—Hydrogen Systems

<table>
<thead>
<tr>
<th>System Component</th>
<th>High-Cost Case Values</th>
<th>Mid-Range Case Values</th>
<th>Low-Cost Case Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel cell system installed capital cost ($2008)</td>
<td>$3,000/kW</td>
<td>$813/kW</td>
<td>$434/kW</td>
</tr>
<tr>
<td>Stack replacement frequency/cost</td>
<td>13 yr/30% of initial capital cost</td>
<td>15 yr/30% of initial capital cost</td>
<td>26 yr/30% of initial capital cost</td>
</tr>
<tr>
<td>O&amp;M costs</td>
<td>$50/kW-yr²</td>
<td>$27/kW-yr</td>
<td>$20/kW-yr²</td>
</tr>
<tr>
<td>Fuel cell life</td>
<td>13 yr (20,000-hour operation)</td>
<td>15 yr (24,000-hour operation)</td>
<td>26 yr (40,000-hour operation)</td>
</tr>
<tr>
<td>Fuel cell system efficiency (LHV)</td>
<td>47%</td>
<td>53%³</td>
<td>58%⁴</td>
</tr>
</tbody>
</table>

1. DOE (2007), Chapter 3.4; 20,000 hours for stationary PEM reformate system fuel cells 5–250 kW has been demonstrated. The goal for 2011: “By 2011, develop a distributed generation PEM fuel cell system operating on natural gas or LPG that achieves 40% electrical efficiency and 40,000 hours durability at $750/kW.” Validated by 2014. Twenty thousand hours (13 years) was used for the high-cost value, and 40,000 hours (26 years) was used for the low-cost value.

2. Values are from Lipman et al. (2004).

3. Current technology value for stack efficiency is approximately 55% (O’Hayre et al. 2006). Value is mid-way between the high and low estimates.

4. Assumed stack efficiency of 60% (MYPP 2010 target for direct hydrogen fuel cells for transportation) with 2% conversion losses for integrated system.
### Backup Slides—Hydrogen Systems

**Hydrogen Fueled Gas Turbine**—Cost values and projections based on literature review

<table>
<thead>
<tr>
<th>Source</th>
<th>Year</th>
<th>Raw data</th>
<th>Converted $2008/kW</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Afgan and Carvalho (2004)</td>
<td>2004</td>
<td>750 €/kW</td>
<td>$1,044</td>
<td>From Onanda.com historical data, using avg euro:usd for 2004 = 1.244; based on simple natural gas turbine plant</td>
</tr>
<tr>
<td>Phadke et al. (2008)</td>
<td>2008</td>
<td>$758/kW</td>
<td>$758</td>
<td>Compares several coal cycles, this is plant for CCGT</td>
</tr>
<tr>
<td>Siemens (2007)</td>
<td>2008</td>
<td>&lt; $1,000</td>
<td>$1,000</td>
<td>&quot;Power block (equipment + construction): 2 hydrogen-fueled GTs, 2 HRSGs, 1 steam turbine, 3 generators and all associated auxiliaries/controls/BOP equipment&quot;</td>
</tr>
<tr>
<td>Pilavachi et al. (2009)</td>
<td>2008</td>
<td>680 €/kW</td>
<td>$1,001</td>
<td>From Onanda.com historical data, using avg euro:usd for 2008 = 1.47; costs includes total power plant costs - equipment and installation</td>
</tr>
</tbody>
</table>
Backup Slides—Batteries

Cost values primarily based on two Sandia reports (2003 and 2008) and three EPRI reports (2003, 2006, and 2007)

<table>
<thead>
<tr>
<th></th>
<th>Energy Capacity Related Cost (Battery) ($/kWh)</th>
<th>Power Related Cost (PCS) ($/kW)</th>
<th>BoP ($/kWh)</th>
<th>Fixed O&amp;M ($/kW-y)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Nickel Cadmium</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High Case¹</td>
<td>1,570</td>
<td>288</td>
<td>173</td>
<td>5.8</td>
</tr>
<tr>
<td>Mid-Range Case²</td>
<td>1,380</td>
<td>150¹⁰</td>
<td>115 ($/kW)</td>
<td>31</td>
</tr>
<tr>
<td>Low-Range Case⁴</td>
<td>690</td>
<td>144</td>
<td>173</td>
<td>5.8</td>
</tr>
<tr>
<td><strong>Sodium Sulfur</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High Case⁵</td>
<td>288</td>
<td>173</td>
<td>58</td>
<td>23</td>
</tr>
<tr>
<td>Mid-Range Case⁶</td>
<td>226</td>
<td>235</td>
<td>115 ($/kW)</td>
<td>59</td>
</tr>
<tr>
<td>Low-Range Case</td>
<td>30% reduction from mid-range case³</td>
<td>173</td>
<td>58</td>
<td>59</td>
</tr>
<tr>
<td><strong>Vanadium Redox⁹</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>High Case⁷</td>
<td>300</td>
<td>1800</td>
<td>500 ($/kW)</td>
<td>54.8</td>
</tr>
<tr>
<td>Mid-Range Case⁸</td>
<td>210</td>
<td>750</td>
<td>500 ($/kW)</td>
<td>54.8</td>
</tr>
<tr>
<td>Low-Range Case⁸</td>
<td>210</td>
<td>500</td>
<td>500 ($/kW)</td>
<td>54.8</td>
</tr>
</tbody>
</table>

1. High Case: High performance, high cost.
3. Low-Range Case: Low performance, low cost.
5. Sodium Sulfur: Mid-range technology with moderate cost.
2. EPRI-DOE (2003).
3. PCS cost is derived from equation in EPRI-DOE (2003) for a programmed response PCS without VAR support; $/kW ($2003) = 11,500 * Vmin-0.59 where Vmin is the minimum discharge voltage (maximum current).
6. Values from EPRI-DOE (2003), NKG Insulators Ltd, E50 peak shaving battery (50-kW modules).
7. Electrolyte costs are not expected to decrease in the future due to the cost of vanadium. Electrolyte makes up about 30% of the capital cost of the system. However, future improvements in the system are expected to result in some cost reduction. Electrolyte costs decrease from $256/kWh to $151/kWh for the future case.
8. EPRI (2007) “present day” costs. Replacement cost for cell stack only at “future” cost.
Backup Slides—Pumped Hydro and CAES

Pumped Hydro System Costs

<table>
<thead>
<tr>
<th></th>
<th>Storage System Including PCS</th>
<th>BoP ($/kWh)</th>
<th>Fixed O&amp;M ($/kW-y)</th>
</tr>
</thead>
<tbody>
<tr>
<td>High-cost case</td>
<td>$12/kWh + $1,209/kW</td>
<td>5</td>
<td>2.9</td>
</tr>
<tr>
<td>Mid-range case</td>
<td>$12/kWh + $1,151/kW</td>
<td>5</td>
<td>2.9</td>
</tr>
<tr>
<td>Low-cost case</td>
<td>$12/kWh + $888/kW</td>
<td>0</td>
<td>2.9</td>
</tr>
</tbody>
</table>

Cost values based on literature review and existing installations
- Schoenung and Hassenzahl (2003)
- Capacity and Cost Information for 1,000-MW and Larger Pumped Hydro Installations Worldwide (Electricity Storage Association 2009)

CAES System Costs

<table>
<thead>
<tr>
<th></th>
<th>Storage System Including PCS</th>
<th>BoP ($/kWh)</th>
<th>Fixed O&amp;M ($/kW-y)</th>
<th>Natural Gas Heat Rate (Btu/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>High-cost case</td>
<td>$3.45/kWh + $490/kW</td>
<td>58</td>
<td>2.9</td>
<td>6,000</td>
</tr>
<tr>
<td>Mid-range cost case</td>
<td>$34.54/kWh + $403/kW</td>
<td>0</td>
<td>6.9</td>
<td>4,000</td>
</tr>
<tr>
<td>Low-cost case</td>
<td>$1.15/kWh + $403/kW</td>
<td>0</td>
<td>6.9</td>
<td>3,800</td>
</tr>
</tbody>
</table>

- Schoenung and E yer (2008)
- Nakhamkin (2007)
- van der Linden (2006)
- EPRI-DOE (2004)
- Schoenung and Hassenzahl (2003)
- EPRI-DOE (2003)
### Backup Slides—Efficiency

#### System (Mid-Range Case @ $0.038/kWh) vs. Roundtrip Efficiency (%)

<table>
<thead>
<tr>
<th>System</th>
<th>Roundtrip Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel cell/aboveground storage</td>
<td>34 (LHV)</td>
</tr>
<tr>
<td>Fuel cell/geologic storage</td>
<td>35 (LHV)</td>
</tr>
<tr>
<td>Hydrogen expansion/combustion turbine</td>
<td>48 (LHV)</td>
</tr>
<tr>
<td>CAES¹</td>
<td>53</td>
</tr>
<tr>
<td>Nickel cadmium battery</td>
<td>59</td>
</tr>
<tr>
<td>Sodium sulfur battery</td>
<td>77</td>
</tr>
<tr>
<td>Vanadium redox battery</td>
<td>72</td>
</tr>
<tr>
<td>Pumped hydro</td>
<td>75</td>
</tr>
</tbody>
</table>

1. AC-to-AC roundtrip efficiency for the CAES system is defined as the total electricity output divided by the total energy input (electricity plus natural gas).
## Analysis Matrix

<table>
<thead>
<tr>
<th>Peak Electricity</th>
<th>Spinning Reserve</th>
<th>Base Load</th>
<th>System Size</th>
<th>Compare to: (Management Strategy)</th>
<th>Compare to: (Storage Method)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydrogen for Base Loading</td>
<td>X</td>
<td>X</td>
<td>Large</td>
<td>o Curtail wind o Turn down base capacity o Buy electricity</td>
<td>Pumped hydro CAES</td>
</tr>
<tr>
<td>Hydrogen for Base Loading (Rev. FC)</td>
<td>X</td>
<td>X</td>
<td>Large</td>
<td>o Curtail wind o Turn down base capacity o Buy electricity</td>
<td>Pumped hydro CAES</td>
</tr>
<tr>
<td>Hydrogen for Vehicles</td>
<td>X</td>
<td>X</td>
<td>Medium</td>
<td>o Curtail wind o Turn down base capacity</td>
<td>Batteries</td>
</tr>
<tr>
<td>Hydrogen for Vehicles (Rev. FC)</td>
<td>X</td>
<td>X</td>
<td>Medium</td>
<td>o Curtail wind o Turn down base capacity</td>
<td>Batteries</td>
</tr>
</tbody>
</table>
Table 1. Costs of Geologic Storage Cavern Development for CAES and Hydrogen

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Solution-mined salt caverns</td>
<td>1.00</td>
<td>1.20</td>
<td>2.88</td>
<td>0.02</td>
</tr>
<tr>
<td>Dry-mined salt caverns</td>
<td>10.00</td>
<td>11.50</td>
<td>27.60</td>
<td>0.16</td>
</tr>
<tr>
<td>Rock caverns created by excavating comparatively impervious rock formations</td>
<td>30.00</td>
<td>35.00</td>
<td>84.00</td>
<td>0.49</td>
</tr>
<tr>
<td>Naturally occurring porous rock formations (e.g., sandstone and fissured limestone) from depleted gas or oilfields</td>
<td>0.10</td>
<td>0.12</td>
<td>0.29</td>
<td>0.002</td>
</tr>
<tr>
<td>Abandoned limestone or coal mines</td>
<td>10.00</td>
<td>11.50</td>
<td>27.60</td>
<td>0.16</td>
</tr>
<tr>
<td>Geologic storage of hydrogen</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>0.30</td>
</tr>
</tbody>
</table>

¹Hydrogen storage cavern development cost is calculated assuming the same $/m³ as for CAES cavern development and energy density from Crotogino and Huebner (2008).
³Equation from H2A Delivery Scenario Analysis Model Version 2.02, for 41,000-kg usable storage capacity, www.hydrogen.energy.gov/h2a_delivery.html.
Backup Slides—Geologic Storage in Salt Deposits
(Source: Casey 2009)

Figure 2 - Known Salt Deposits in the United States
(after Anon., 1980B).


The cost of delivered energy from the vanadium redox battery systems is most sensitive to the price of the electrolyte.
Schematic for Alabama McIntosh 110-MW CAES Plant

Compressors (50 MW) -> Expanders (110 MW)

- After-cooler
- Intercoolers
- Ambient Air
- Motor/Gen
- Recuperator
- Exhaust Stack

Salt Cavern Air Store:
Distance to Surface = 1500 ft
Height = 1000 ft
Avg. Diameter = 156 ft
Volume = 22 MCF

Underground Storage Cavern:
A Solution Mined Salt Cavern

Heat Rate
Energy Ratio | 4100 | 0.81

Study References


## Benchmarking—Other Benefits and Drawbacks of Hydrogen Energy Storage Relative to Alternatives

### System Operation

<table>
<thead>
<tr>
<th>Benefits</th>
<th>Drawbacks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Modular (can size the electrolyzer separately from FC to produce extra hydrogen)</td>
<td>Low electrolysis/FC round trip (AC to AC) efficiency (50–55%)&lt;br&gt;Even lower round-trip efficiency when hydrogen is used in a combustion turbine (&lt;40%)</td>
</tr>
<tr>
<td>Very high energy density for compressed hydrogen (&gt;100 times the energy density for compressed air at 120 bar ∆P, CC GT)</td>
<td>Hydrogen storage in geologic formations other than salt caverns may not be feasible</td>
</tr>
<tr>
<td>System can be fully discharged at all current levels</td>
<td>Electrolyzers and fuel cells require cooling</td>
</tr>
</tbody>
</table>

### Cost

<table>
<thead>
<tr>
<th>Benefits</th>
<th>Drawbacks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Research has potential to drive down costs</td>
<td>Use of precious metal catalysts for low-temperature fuel cells</td>
</tr>
<tr>
<td></td>
<td>Currently high cost relative to competing technologies (&gt;1000/kW)</td>
</tr>
</tbody>
</table>

## Benefits and Drawbacks of Hydrogen Energy Storage

<table>
<thead>
<tr>
<th>Environmental</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Benefits</strong></td>
<td><strong>Drawbacks</strong></td>
</tr>
<tr>
<td>Catalyst can be reclaimed at end of life</td>
<td>Environmental impacts of mining and manufacturing of catalyst</td>
</tr>
<tr>
<td>Low round-trip efficiency increases emissions for conventional electricity and reduces replacement by renewables</td>
<td></td>
</tr>
</tbody>
</table>

# Benefits and Drawbacks of Battery Energy Storage

## System Operation

<table>
<thead>
<tr>
<th>Benefits</th>
<th>Drawbacks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Modular</td>
<td>Battery voltage to current relationship limits the amount of energy that can be extracted, especially at high current</td>
</tr>
<tr>
<td>Mid range to high round trip efficiency (65%–75%)</td>
<td></td>
</tr>
</tbody>
</table>

## Cost

<table>
<thead>
<tr>
<th>Benefits</th>
<th>Drawbacks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sodium sulfur and Vanadium Redox battery system cost</td>
<td>Nickel cadmium battery system cost</td>
</tr>
<tr>
<td>High round-trip efficiency reduces arbitrage scenario costs</td>
<td></td>
</tr>
</tbody>
</table>

## Environmental

<table>
<thead>
<tr>
<th>Benefits</th>
<th>Drawbacks</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Toxic and hazardous materials</td>
</tr>
</tbody>
</table>

# Benefits and Drawbacks of Pumped Hydro Energy Storage

<table>
<thead>
<tr>
<th>System Operation</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Benefits</strong></td>
<td><strong>Drawbacks</strong></td>
</tr>
<tr>
<td>Well established and simple technology</td>
<td>System requires large reservoir of water (or suitable location for reservoir)</td>
</tr>
<tr>
<td>High round-trip efficiency (70%–80%)</td>
<td>System requires mountainous terrain</td>
</tr>
<tr>
<td></td>
<td>Extremely low energy density (0.7 kWh/m³)</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Cost</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Benefits</strong></td>
<td><strong>Drawbacks</strong></td>
</tr>
<tr>
<td>Inexpensive to build and operate</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Environmental</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Benefits</strong></td>
<td><strong>Drawbacks</strong></td>
</tr>
<tr>
<td>No toxic or hazardous materials</td>
<td>Large water losses due to evaporation, especially in dry climates</td>
</tr>
<tr>
<td></td>
<td>Habitat loss due to reservoir flooding</td>
</tr>
<tr>
<td></td>
<td>Stream flow and fish migration disruption</td>
</tr>
</tbody>
</table>

## Benefits and Drawbacks of Compressed Air Energy Storage

### System Operation

<table>
<thead>
<tr>
<th>Benefits</th>
<th>Drawbacks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proposed advanced designs store heat from compression giving theoretical efficiency of 70%—comparable to pumped hydro</td>
<td>Low round-trip efficiency (54%) with waste heat from combustion used to heat expanding air—42% without</td>
</tr>
<tr>
<td></td>
<td>Very low storage energy density (2.4 kWh/m³)</td>
</tr>
<tr>
<td></td>
<td>Must be located near suitable geologic caverns</td>
</tr>
</tbody>
</table>

### Cost

<table>
<thead>
<tr>
<th>Benefits</th>
<th>Drawbacks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low cost</td>
<td></td>
</tr>
</tbody>
</table>

### Environmental

<table>
<thead>
<tr>
<th>Benefits</th>
<th>Drawbacks</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Approximately 1/3 of output energy is derived from natural gas feed to combustion turbines resulting in additional GHG emissions</td>
</tr>
</tbody>
</table>