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Comparison of Storage Technologies for Distributed Resource Applications

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Technical Update, February 2003

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PRODUCT DESCRIPTION

This report summarizes six electricity storage technologies by describing operating principles, technical characteristrics, field experience, and capital and operating costs:

- Sodium Sulfur (NAS) Battery
- Polysulfide-bromine (PSB) Battery (“Regensys”)
- Vanadium Redox Battery (VRB)
- Compressed Air Energy Storage (CAES)
- Flywheels
- Electrochemical Capacitors

In addition, the data is used to compare storage technologies in four applications: (1) peak shaving on the customer side of the meter, (2) peak shaving on the utility side of the meter, (3) customer carryover during power disturbances, and (4) hybrid diesel/battery microgrids. A methodology was developed to evaluate economic feasibility of each application, and companion spreadsheet models were developed. Technical and economic inputs and results for each technology are presented.

Results & Findings

The report provides a side-by-side comparison of storage technologies for four applications of interest to utilities and their customers. For peak shaving, a downsized CAES system is shown to be potentially the most economic technology (12% after-tax IRR for customer-owned systems and 4.2 benefit/cost ratio for utility-owned systems). While CAES has high variable operating costs relative to the electrochemical storage technologies, this application has relatively infrequent cycling demands. Both the flywheel and capacitor technologies look attractive for power carryover in comparison with conventional in-line UPS technologies. In a 20 MW hybrid diesel/battery microgrid, all of the long-term storage technologies were at least as economic as an all-diesel system (NPV $60M), and the two flow batteries (PSB and VRB) were significantly lower in cost (NPV $47M and $41M, respectively). Microgrids may be a strong candidate application for storage.

Challenges & Objectives

This report is useful for utility T&D managers, engineers, marketing representatives, and researchers considering the use of storage in their system. It describes the technologies that may be considered for their use, characterizes their state of maturation, and provides modeling and analysis to guide them in their selection of application. Utilities can potentially use storage to reduce their operating costs in peak shaving and microgrid applications. They can also provide information from this report to their customers in order to help reduce their demand charges and enhance their reliability.

Applications, Values & Use

The report covers six storage technologies and four applications. Other storage technologies are under development, and these may also play an important role in T&D applications. Future work will examine zinc-bromine technology, which is a near-commercial, low cost alternative for long-term storage. As field experience increases with all of these technologies, more accurate and complete information will become available. Also, storage applications are increasingly recognized by utilities, and it is likely that other applications will be identified and developed.

EPRI Perspective

This report, contains storage technology cost and performance data that is not available to the public. It contains information that is specific to technology suppliers, rather than containing generic technology data. The methodologies developed in this report are not publicly available. The funders of this report have access to the spreadsheet models that they can use directly for their own analysis, saving them considerable development time. The report is also unique in that it provides convenient, up-to-date, and detailed cost and performance data for these technologies in a single report.

Approach

The purpose of this report is to characterize the status and prospects of storage technologies for DER/T&D applications. Since these are new technologies and new applications of storage, models were developed to provide side-by-side comparisons of the technologies taking into account all of the life-cycle variables. These models, for example, allow CAES (with a 30 year life and significant variable O&M costs) to be compared with electrochemical storage technologies (10 to 15 year life with no significant variable O&M costs). The relative capital costs, efficiencies, and other factors are all incorporated into meaningful comparative results.

Keywords

- Energy storage
- Electricity storage
- Distributed Energy Resources
- Peak Shaving
- Power Quality
- Hybrid Systems
- Microgrids
- Sodium Sulfur (NAS) Battery
- Polysulfide-bromine (PSB) Battery
- Regensys
- Vanadium Redox Battery (VRB)
- Compressed Air Energy Storage (CAES)

- Flywheels
- Electrochemical Capacitors

ABSTRACT

This report contains cost, performance and technology readiness data for the Sodium Sulfur (NAS) Battery, the Polysulfide-bromine (PSB) Battery ("Regensys"), the Vanadium Redox Battery (VRB), Compressed Air Energy Storage (CAES), flywheels, and electrochemical capacitors. Data is used to compare storage technologies in four DER/T&D applications: (1) peak shaving on the customer side of the meter, (2) peak shaving on the utility side of the meter, (3) customer carryover during power disturbances, and (4) hybrid diesel/battery microgrids. Methodologies are developed and presented to evaluate economic feasibility of each application, and technical and economic inputs and results for each technology are presented.

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1 INTRODUCTION

EPRI is currently producing a set of guidelines for the application of energy storage technology in the electric utility T&D system. These guidelines, in the form of a Handbook (EPRI, 1007189), will provide funders with credible and timely cost, performance and technology readiness data for a variety of storage technology options.

As an ancillary effort, EPRI has commissioned the present summary of the Handbook technology information and an assessment of these technologies as they relate to specific distributed resource (DR) applications. The work includes the development of companion analytical spreadsheet models that may be used for further analyses as desired.

The specific technologies considered under this summary include:

- Sodium Sulfur (NAS) Battery
- Polysulfide-bromine (PSB) Battery ("Regensys")
- Vanadium Redox Battery (VRB)
- Compressed Air Energy Storage (CAES)
- Flywheels
- Electrochemical Capacitors

The applications modeled in the spreadsheets include:

- Peak Shaving (customer ownership scenario)
- Peak Shaving (utility ownership scenario)
- Power Carryover
- Hybrid Off-grid Systems / Microgrids

For each technology, the "Technology Descriptions" section provides background on the development efforts, the operating principles, technical characteristics, field experience, and capital and O&M costs as reported in the Handbook. This data is then summarized for reference in tables in the "Technologies Summary" section. For more detailed information, the reader is referred to the Handbook itself.

Each application is described in terms of the operating requirements, the non-storage alternative, and the relevant technology cost and performance variables. The methodology and assumptions are provided as background information to the spreadsheet models, and the rationale for key economic tests is presented. Finally, each technology is compared using the model and the relevant economic figure of merit for each application

2
TECHNOLOGY DESCRIPTIONS

Sodium Sulfur (NAS) Battery

The sodium-sulfur battery dates from initial work conducted by Ford Motor Company in the 1960s. Other developers continued in Europe, Japan, and North America through the 1980s for transportation, stationary power, and satellite communications applications. Tokyo Electric Power Company (TEPCO) selected the NAS battery for utility-scale stationary power applications, and formed an alliance with NGK Insulators, Ltd. (NGK) in Japan in the production of critical ceramic components. At present, NGK is the only known supplier for utility applications, and the technology presented herein pertains to NGK's sodium-sulfur (NAS®, registered in Japan) battery module.

Principles of Operation

The NAS battery is based upon a high-temperature (300° C) electrochemical cell. The cell consists of a molten sodium (negative) electrode at the center surrounded by a safety tube, a solid ceramic beta alumina tube (the electrolyte), and a sulfur (positive) electrode. In its charged state, liquid elemental sodium fills the central reservoir. As the cell is discharged, the liquid sodium is channeled through the narrow annulus between the inner surface of the electrolyte and the safety tube, a design feature to limit the amount of sodium and sulfur that can potentially combine and release heat. Figure 2-1 shows the cell components and module.

Figure 2-1
NAS Cell Components and Module

During discharge, the sodium electrode is oxidized at the sodium/beta alumina interface, forming Na^+ ions. These ions migrate through the electrolyte and combine with the sulfur to reduce the positive electrode, forming sodium pentasulfide (Na_2S_5). The sodium pentasulfide is immiscible with the remaining sulfur, thus forming a two-phase liquid mixture. After the free sulfur is consumed, the Na_2S_5 is progressively converted into single-phase sodium polysulfides with progressively higher sulfur content (Na_2S_{5-x}). Cells undergo exothermic and ohmic heating during discharge. During charge, these chemical reactions are reversed.

Cell open circuit voltages range from about 2.08 V down to about 1.8 V. These are combined into battery modules in which the series and parallel connections are optimized for either high energy or high power applications. Cells are closely spaced, surrounded by sand that functions as both a packing material and a heat sink. Modules incorporate a thermally insulated enclosure equipped with electric heaters to maintain operating temperature, and a vacuum is drawn on the gap between the inner and outer walls of the enclosure to minimize heat loss.

NGK has developed the NAS T5 cell for use in both commercial battery modules, designated the NAS PS (for peak shaving) Module and the NAS PQ (for power quality) Module. Cell and module characteristics are shown in Table 2-1.

Table 2-1
NAS Cell and Module Characteristics

Parameter	NAS T5 Cell	NAS PS Module	NAS PQ Module
Nominal Voltage, Vdc	2	64 or 128	640
Cell Arrangement ("s" series; "p" parallel)	NA	(8s X 5p) x8s or (8s X 10p) x4s	320s
Rated Energy Capacity, (100% DOD in 7.2 hr EOL)	1.25 kWh	375 kWh DC at 52.6 kW DC	
Calendar & Cycle Life	15 years; 2500, 100% depth of discharge cycles		
Max Power (kW) for Min Duration (noted)	NA	60 kW for 3 hr	250 kW for 30 sec
Avg DC Efficiency, %	89	84	
Initial Standby Heat Loss, kW	NA	3.4	2.2 (PQ) 3.4 (PQ+PS)[1]
Dimensions, mm	515L x 91	2,270 Wx1,740 D x 720 H	
Weight, kg	5.5	3,500	

Footprint

The footprint of a NAS system, including modules, cabinetry, and PCS is 50-100 m^2/MW. This figure also includes space for access and maintenance.

Maintenance Requirements

The NAS battery system has been developed to require minimal onsite maintenance and is capable of unattended, fully automatic operation. NGK's recommended maintenance program consists of continuous remote monitoring and detailed inspections conducted at 3-year intervals which include: inspecting for unusual vibrations, noise or odors; inspecting for abnormal conditions of connecting cables and the exterior enclosure; inspecting insulation resistance; re-torquing terminals; collecting and analyzing battery resistance and OCV data; confirming the accuracy of DC voltage, DC current, and temperature sensors; adjusting module enclosure vacuum to control standby heat loss (every 1,000 cycles).

Life

Module replacements would be required every 10 or 15 years, depending upon duty cycle. Since the modules make up most of the capital cost, it is reasonable to expect minimum salvage value

[1] The PQ module is capable of both high power and high energy applications. The standby losses are shown for PQ-only and combined PQ/PS applications.

for the battery, i.e., the entire battery and enclosure would be replaced at the end of life. However, the PCS and controls may be reusable in the new installation.

Efficiency

System efficiency depends upon the application, the module used, and the duty cycle, but roundtrip efficiency is typically on the order of 70-75% for a given cycle, including rectifier, inverter and DC columbic and voltaic efficiencies. The annual efficiencies are higher when cycling does not occur on a daily basis. A breakdown of efficiency is shown in Table 2-2. for plant designs for various applications.

Response Time

Response time depends upon the requirements of the application, but can be within 4 milliseconds, if required.

Environmental Impact

Waste disposal and materials recycling is required in Japan and most other developed countries. NGK estimates that 98% of NAS materials can be recycled. Only sodium requires recycling as a hazardous material.

Field Experience

NGK has fielded about 20 demonstration and early commercial projects above 500 kW, with the largest rated at 6 MW / 48 MWh at the TEPCO Ohio Substation (Figure 2-2). About 30 projects below 500 kW are in progress in Japan. The first demonstration of NAS technology in the US, a multimode system for peak shaving (100 kW / 720 kWh) and power quality (500 kW / 30 seconds), was commissioned in September 2002 at American Electric Power Company (AEP) in Gahanna, Ohio. In April 2002, NGK announced construction of expanded manufacturing facilities in Japan with an initial capacity commitment for 1,000 modules per year in 2003. A list of key NGK projects is shown in Table 2-2.

Figure 2-2
6 MW / 48 MWh NAS System at TEPCO Ohio Substation

Table 2-2
NGK Project Experience

No.	Customer	Site	kW/kWh	Purpose	Start of Operation
1	TEPCO	Kawasaki Test Site	500/4,000	Load Level	Jun-95
2	TEPCO Unit 1	Tsunashima Substation	6,000/48,000	Load Level	Mar-97
	TEPCO Unit 2	(Unit 2 relocated, see "5")			Jul-97
	TEPCO Unit 3				Jan-98
3	NGK	Head Office	500/4,000	Load Level	Jun-98
4	TEPCO Unit 1	Ohito Substation	6,000/48,000	Load Level	Mar-99
	TEPCO Unit 2	(Unit 2 relocated, see "18")			Jun-99
	TEPCO Unit 3				Oct-99
5	TEPCO/TOKO	Saitama	2,000/16,000	Reloc "2", LL	Jun-99
6	Chubu EPCO	Odaka Substation	1,000/8,000	Load Level	Mar-00
7	TEPCO	Tsunashima Substation (New Unit 2)	2,000/14,400	Load Level	Nov-00
8	TEPCO	Shinagawa Substation	2,000/14,400	Load Level	Mar-01
9	TEPCO/Asahi Brewery	Kanagawa Plant	1,000/7,200	LL+UPS	Oct-01
10*	Metro City of Tokyo	Kasai Sewerage	1,200/7,200	LL+UPS	Oct-01
11	TEPCO/Takaoka	Oyama Plant	600/1,440	LL+UPS	Oct-01
12	TEPCO/Takaoka	Oyama Plant	800/5,760	Load Level	Feb-02
13	TEPCO/Fuji Xerox	Ebina Plant	1,000/7,200	Load Level	Feb-02
14	TEPCO/Pacifico	Media Center	2,000/14,400	LL+UPS	Apr-02
15	TEPCO	Chichibu Substation	1,000/7,200	Load Level	Jun-02
16*	TEPCO/Fujitsu	Akiruno Technology Ctr	3,000/7,200	LL+UPS (PQ=3)	Jun-02
17*	TEPCO/Tokyo Dome	Tokyo Dome Renovation	1,000/7,200	LL+EPS	Jul-02
18*	TEPCO/Ito Yokado	Maebashi Shopping Ctr	1,000/7,200	Reloc "4", LL	Jul-02
19	AEP	Gahanna, OH, USA	500/720	LL+UPS (PQ=5)	Aug-02

* Early commercial projects

Capital and Operating Costs

Conceptual plant designs are shown in Table 2-3 for four T&D applications. Based upon the required ratings, plant capital and operating costs are shown in Table 2-4.

Table 2-3
NAS Plant Design Characteristics

Application	NAS System Rated Power, MW	NAS Discharge Duration (Note 1)	Capacity, MWh (Note 2)	NAS System Duty Cycle	NAS System Efficiency, % (Note 3)	NAS System Footprint, (MW/m^2) (Note 4)
Load-Leveling	10 (200 NAS PS Modules)	7.2hr equivalent duration for rated power	72	167 days/year (equivalent to 8 months)	Net: 91.5% ES Cycle: 75.8% Standby: ….NAS: 94.8% ….PCS: NA	Net: 0.010 ….NAS: 0.016 ….PCS: 0.027
Power Quality Protection & Grid Support	10 (40 NAS PQ Modules)	Up to 30 seconds	0.42	100 cycles/year on demand (5 discharges within 1 hour without recharging)	Net: 97.1% ES Cycle: ~70% Standby: ….NAS: 99.1% ….PCS: 98%	Net: 0.020 ….NAS: 0.079 …..PCS: 0.027
Automatic Generation Control	26 (200 NAS PQ Modules)	Up to 1 hour for a single event	26	75 cycles/year on demand, (12-hr interval between cycles)	Net: 96.4% ES Cycle: ~70% Standby: ….NAS:98.5% ….PCS: 98.1%	Net: 0.016 ….NAS: 0.041 ….PCS: 0.027
20MW Wind Farm Stabilization	2 (40 NAS PS Modules)	Up to 9 hours	14.4	~250 cycles/year	Net: 89.6% ES Cycle: 75.8% Standby: ….NAS: 96.6% ….PCS: 99.1%	Net: 0.010 ….NAS: 0.016 ….PCS: 0.027

Notes:
(1) Design basis NAS system discharge duration at rated power for each event.
(2) Design basis NAS battery energy discharge between recharging intervals expressed as energy delivered to the load after conversion and storage losses, e.g., “AC” MWh.
(3) “Net” and “standby” efficiencies are expressed on an annual basis and include losses for energy conversion and system standby (e.g., NAS heating, PCS hot standby). “ES cycle” efficiency is expressed as the ratio of energy delivered to energy supplied and include rectifier, inverter and NAS DC efficiencies for a single cycle.
(4) NAS space requirements are based on an exterior enclosure with stacks of 5 modules and includes space for fork lift access.

Table 2-4
NAS Capital and O&M Costs

Application	NAS System Rated Power, MW	NAS Battery Capacity, ACMWh	PCS & BOP Initial Cost, $/kW (Note 1)	NAS Battery Initial Cost $/kWh (Note 2)	Total Capital Cost, M$	O&M Cost – Fixed, $/kW (Note 3)	O&M Cost – Variable, $/kW (Note 4)
Load-Leveling	10 (200 NAS PS Modules)	72	250	192	16.3	9	12.4
Power Quality Protection & Grid Support	10 (40 NAS PQ Modules)	0.42	300	7,305	6.0	6.6	8.8
Automatic Generation Control	26 (200 NAS PS Modules)	26	300	585	23.0	7.2	10
20 MW Wind Farm Stabilization	2 (40 NAS PQ Modules)	14.4	300	192	3.4	9	7.5

Notes:
1. Includes installed cost of power electronics, system interface plus balance of plant scope
2. Includes NAS scope of supply (see text) plus installation and space, estimated at $1100 per module
3. Based on 3 hours technician labor per module per year at $50 per hour plus $6/kW for PCS maintenance
4. Includes electricity consumption for NAS heating and for PCS "hot" standby as appropriate to the application

Polysulfide-bromine (PSB) Battery

The polysulfide-bromine (PSB) battery was developed in the early 1990s by Ralph Zito who later assigned technology rights to Innogy (formerly National Power), a subsidiary of RWE in the UK. Known more commonly under its trade name Regenesys, the PSB is a flowing-electrolyte battery (or "flow battery") in which its reactants and products are stored in tanks external to reactor cell stacks. Liquid electrolyte is mechanically pumped from the tanks into the stacks by a hydraulic system of pipes and manifolds where it is distributed to individual cells.

Principles of Operation

During discharge, the reaction at the positive electrode is given by:

$$NaBr_3 + 2Na^+ + 2e^- \rightarrow 3\ NaBr$$

and the reaction at the negative electrode is:

$$2Na_2S_2 \rightarrow Na_2S_4 + 2Na^+ + 2e^-$$

During charge, the reverse of the above reactions takes place. A cation-exchange membrane separates the anolyte and catholyte in the positive and negative compartments of each cell while providing a path for the passage of sodium ions. A simple flow schematic is shown in Figure 2-3.

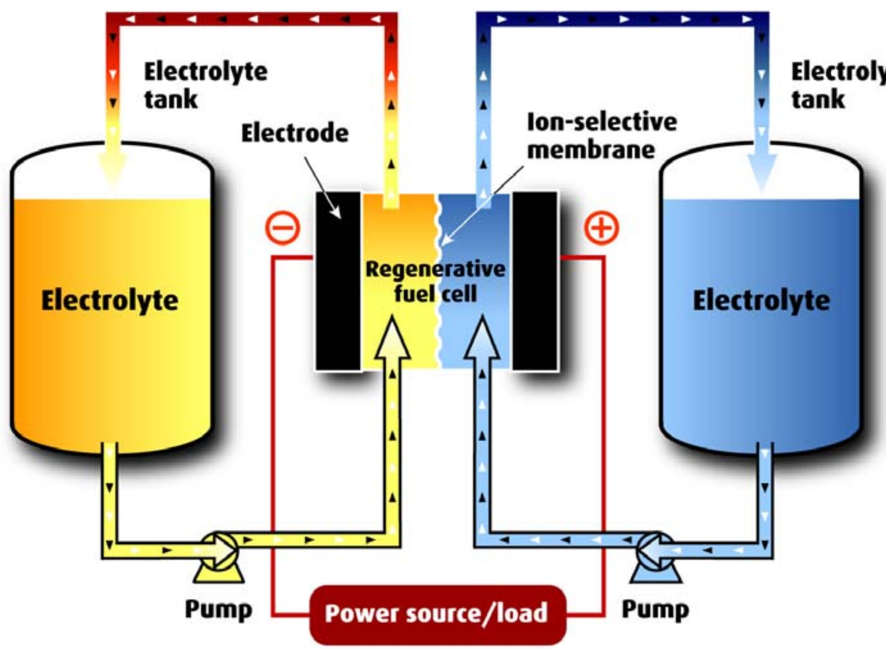

Figure 2-3
Flow Schematic of Regenesys Electricity Storage System

Each cell has open circuit voltages of about 1.5 V and a cross-section of up to one square meter. These are combined in series to create stacks of about 300 V. Cell stacks consist of bipolar electrode plates spaced and held by insulating polymer frames that also serve as manifolds to distribute electrolyte into the cell compartments. Frames are sealed to prevent electrolyte leakage between cell compartments and out of the stack, and are held together with thick end plates and tie bars that span the length of stack. Each stack is rated at 100 kW (Figure 2-4), and these are arranged in series and parallel to produce the desired voltage and current ratings.

Figure 2-4
Regenesys 100 kW XL Module

As with other flow batteries, the PSB provides certain benefits such as simplified thermal management since heat is removed from the stacks by the electrolyte flow. Since all cells share the same electrolyte at the same state of charge, high-voltage charging for cell equalization is not required, enhancing safety and stack life. On the other hand, the pumps add complexity to system design, draw parasitic power, and require periodic repair or replacement.

Footprint

Innogy indicates that a 100 Wh/10 MW plant will occupy 1 hectare (2.5 acres) or less. This corresponds to a footprint of slightly less than 1 kWh/ft^2, or not too dissimilar to the total site area for single-story plant based on flooded lead-acid cells.

Maintenance requirements

Within the fifteen year life expected for the plant, Innogy projects that 3-month inspections will be necessary, and that occasional repairs of some of the mechanical components (pumps, valves, etc.) might be anticipated. Moreover, the crystalline sodium sulfate that is the end product of inefficiency of the membranes will have to be collected from the negative electrolyte every two weeks, trucked away, and sold or disposed of away from the site.

Life

Innogy designs plants with a 15-year life. Since there is already considerable experience with the membranes (the expected life-limiting component) under much harsher conditions, this expectation does not appear unwarranted.

Efficiency

Innogy estimates that the round-trip energy efficiency (AC energy out versus AC energy in) of early Regenesys plants will be 60-65%. Higher than the nominal rates of discharge (15 MW versus 10 MW nominal) are expect to be sustainable for up to a quarter of normal 10 hour discharge time, but in this circumstance the AC-AC efficiency is expected to be 50-55%.

Response Time

Innogy quotes a response time of 100 ms for standby to full-power output. There are several factors that can influence this value, the most important of which is the period for which the full-power output is required. For shorter discharge times (as for transmission stabilization) there should be adequate capacity in the electrolytes contained within the cells for a much shorter response time, assuming of course that the converter is configured and programmed to provide the response. The response time quoted by Innogy is thought to reflect what is required for the Little Barford demonstration plant, rather than that needed to satisfy other applications.

Environmental Impact

Regenesys plants have been designed and configured in such a way as to minimize any environmental impact and so as to ensure the safety of personnel visiting the plant and that of people living nearby. An Environmental Impact Assessment has been prepared which indicates that a Regenesys plant will be environmentally benign.

Field Experience

Innogy has announced that by mid-2003 they should have completed construction and acceptance testing of a demonstration 15 MW (18 MVA) / 120 MWh Regenesys electricity storage plant at the Little Barford power station in the UK. The plant will provide 40 MWh of black start energy for the Little Barford station, energy arbitrage, and voltage control for the network.

More recently, Innogy has contracted to supply TVA with a 12 MW / 120 MWh Regenesys system that will provide a higher level of reliability of electrical service to the Columbus Air Force Base (CAFB) in Mississippi. By mid-2002, according to a TVA spokesman, concrete had been poured, some buildings constructed, tanks were in place, and the main building was being readied for cell-stacks and plumbing.

Capital and Operating Costs

An example Regenesys plant specification is shown in Table 2-5. This 100 MWh plant would be capable of two primary functions: providing 10 MW of transmission support (for 10 hours) and providing frequency regulation on a continuous basis. An artist rendition of the plant is shown in

Figure 2-5. Capital and O&M costs for the plant are shown in Table 2-6, including costs for an initial commercial plant as well as a future plant produced under high manufacturing volumes.

Table 2-5
Regenesys Plant Characteristics

Application	Size MW	Duration Hours	Plant MWh	Response Time	Duty Cycle	Roundtrip Efficiency	Plant Footprint
Transmission Deferral/Support	10	10	100	Seconds	20-200 per year	60-65%	2.5 acres
Area/Frequency Regulation	10	0.25	N/A	100 ms	Continuous in daytime	60-65%	N/A

Figure 2-5
Artist Rendition of 10 MW/100 MWh Regenesys Energy Storage Plant

Table 2-6
Projected Costs for 100 MWh/10 MW Regenesys Energy Storage Plant

Application: Transmission Deferral & Area Regulation	Plant Size MWh	Plant Capacity MW	Capital Cost: Power Related ($/kW)	Capital Cost: Energy Related ($/kWh)	Total Capital Cost (MM$)	O&M Cost: Fixed ($/kW-yr)	O&M Cost: Variable ($/kWh)
1st Commercial Plant	100	10	300	120	15	10	0.01
30th. Plant with 10 plants/year	100	10	150	65	8	1	0.005

Vanadium Redox Battery (VRB)

Like the PSB, the Vanadium Redox Battery (VRB) is a flow battery with electrolyte storage external to the reactor stacks. The VRB provides similar flow design benefits, such as thermal management and cell performance, and complications related to hydraulic design and operation. It is an emerging energy storage technology that is being commercialized for utility applications by Sumitomo Electric Industries (Japan) and Vanteck (VRB) Technology Corporation (Canada). Basic research is essentially complete, and the suppliers have fielded a few demonstration and commercial projects worldwide. These systems have ranged from 100 kW to 1.5 MW and from 2 to 8 hours in discharge duration. However, the technology is not at present produced in commercial volumes.

Figure 2-6
Typical VRB Stacks and Tanks (Courtesy Vanteck)

Principles of Operation

The VRB electrochemistry is based upon electron transfer between different ionic forms of vanadium, a commercially produced metal. At the negative electrode, V^{3+} is converted to V^{2+} during battery charging by accepting an electron. During discharge, the V^{2+} ions are reconverted back to V^{3+} and the electron is released. At the positive electrode, a similar reaction takes place between ionic forms V^{5+} and V^{4+}.

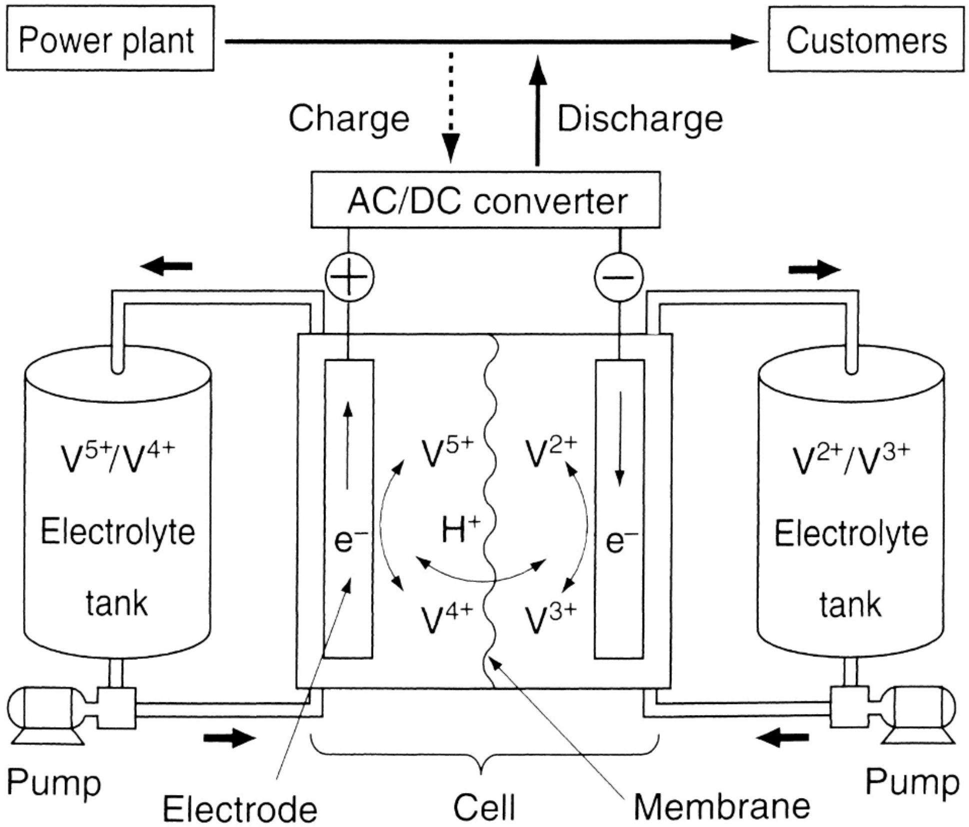

Figure 2-7
Principles of the VRB (Courtesy SEI)

The cell is divided into two half-cells by a proton exchange membrane (PEM). This membrane separates the two different vanadium-based electrolyte solutions – the anolyte and the catholyte – and allows for the flow of ionic charge (protons, or H^+ ions) to complete the electrical circuit. Electrolyte is made up of a vanadium and sulfuric acid mixture at approximately the same acidity level as that found in a lead-acid battery. Electrolyte concentration changes according to the state of charge.

Cells have a nominal voltage of about 1.2 V (DC) and these are stacked electrically in series. In most constructions, "cell stacks" are fed by distributing electrolyte through a manifold to each cell in parallel. However, one unconventional approach incorporates series flow through the stacks to eliminate undesirable stray ionic shunt currents and ensure identical flow through each cell. In series-fed stacks, each cell operates at a different voltage.

Footprint

The main components of the VRB include the storage tanks, pumps and plumbing, cell stacks, and power conversion equipment. Footprint and volumetric space requirements scale with system ratings and can be very site-specific. A 2.5 MW / 10 MWh VRB system is estimated to be 12,000 – 17,000 sq. ft. Therefore, the VRB is more suited to locations in which space is not a primary constraint.

Maintenance Requirements

Without extended field experience, the system maintenance requirements are not well established. However, the primary maintenance items would be annual inspections, and the electrolyte pump bearings and impeller seals would need to be replaced at intervals of about every five years. As necessary, smaller parts, such as electronic boards, sensors, relays, and fuses would be replaced.

Life

The critical system component is the cell stack, which can degrade in performance over time and require replacement or refurbishment. At 100 charge/discharge cycles per year, it is expected that the cell stack would have a life of 10 – 15 years. However, the tanks, plumbing, structural elements, power electronics, and controls would have longer useful lifetimes. It is possible to replace only the stacks, and keep the remainder of the system in place.

Efficiency

The “round trip” (“turnaround”) efficiency – including transformer losses during charge, PCS losses during charge, battery DC losses, PCS losses during discharge, transformer losses during discharge, and pumping losses – is on the order of 70%.

Response Time

The battery is capable of transitioning from zero output to full output in microseconds provided the stacks are primed with reactants. However, the power electronics respond within milliseconds, and the response time of the controls and communications (sensing the load requirements and signaling the PCS to take action) can be even longer. Where response time is important, the control system must be programmed to keep the pumps on and electrolyte flowing through the stacks. This requirement imposes a small performance penalty due to the constant auxiliary losses of the pumps. If response time is not critical, such as in peak shaving applications, then the stacks can be drained and the pumps turned off. This mode eliminates pumping losses and self discharge during downtime. When the battery is called into service, a minute or two would be required to start the pumps and transport electrolyte to the stacks.

Environmental Impact

The VRB stacks, plumbing, and tanks, are primarily composed of recyclable plastic materials, and the electrolyte can be refurbished and reused. There are no toxic chemicals that must be disposed of at the end of life, such as found in other electrochemical storage technologies. For this reason, the VRB is promoted as a “green” storage technology. The only chemical in the VRB system is the vanadium electrolyte, ionic vanadium in sulfuric acid at approximately the same concentration found in flooded lead-acid batteries. Its handling and safety requirements are the same as sulfuric acid. The electrolyte is internally contained within industrial-grade HDPE tanks and pressure-rated PVC pipe and fittings. The VRB is placed within a spill containment area compliant with local regulations.

Field Experience

Vanteck has designed and installed a 250 kW / 2 hour VRB system at the University of Stellenbosch in Cape Town, South Africa in 2001. The system was made from six 42 kW, 100-cell stacks (650 – 850 VDC) arranged in series with two hydraulic systems. The company is currently reusing the same stacks in a 250 kW / 8 hour system in Moab, Utah in a project sponsored by PacifiCorp. SEI has field experience with six major projects, summarized in Table 2-7, covering a range of storage applications.

Table 2-7
SEI Project Experience

Location	Application	Ratings	Operation
Sumitomo Densetsu Co., Ltd.	Peak shaving	100 kW / 8h	Feb 2000
The Institute of Applied Energy	Stabilization of wind turbine output	170kW / 6h	Mar 2001
Tottori SANYO Electric Co., Ltd.	Power quality (voltage sag compensation) and peak shaving	1,500,kW / 1h (3,000 kW instantaneous)	Apr 2001
Obayashi Corp.	Solar PV storage (DC only)	30,kW / 8h	Apr 2001
Kwansei Gakuin University	Peak shaving	500,kW / 10h	Jul 200l
(Italy) CESI	Peak shaving	42 kW / 2h	Nov 2001

Capital and Operating Costs

Estimated VRB plant costs are shown in for three sample applications. These costs include three production scenarios: a prototype plant, a “first of a kind” (FOAK) commercial plant, and an “nth of a kind” (NOAK) plant at mature production levels.

Table 2-8
VRB Plant Capital and O&M Costs

Application	Size	Plant Capacity	Capital Cost – Power Related ($/kW)	Capital Cost – Energy Related ($/kWh)	Total Capital Cost ($)	O&M Cost – Fixed ($/kW-yr)	O&M Cost – Variable ($/kWh)
DR/Peak Shaving							
Prototype	1 MW	4 MWh	2,260	550	4.5 M	12.0	0.029
FOAK			700	230	1.6 M	4.0	0.029
NOAK			500	150	1.1 M	2.0	0.029
Spinning Reserve							
Prototype	10 MW	20 MWh	2,150	1,050	42.5 M	1.2	0.029
FOAK			608	410	14.3 M	0.4	0.029
NOAK			426	250	9.3 M	0.2	0.029
Windfarm Stabilization & Dispatch							
Prototype	10 MW	80 MWh	2150	300	45.5 M	1.2	0.029
FOAK			608	140	17.3 M	0.4	0.029
NOAK			426	100	12.3 M	0.2	0.029

Compressed Air Energy Storage (CAES)

Air can be compressed and stored as potential energy in airtight underground caverns or above ground vessels. When the air is released from storage, it can be expanded through a turbine to generate electricity. In most compressed air energy storage (CAES) plants, off-peak power is used to compress the air, and generation is scheduled during on-peak hours. Hence, the operation of a CAES plant effectively “charges” and “discharges” similar to a battery or other electricity storage technology.

The concept of compressed air energy storage was developed in the 1970s as a means to provide load following, peaking power, and off-peak loads for baseload nuclear plants. CAES is a fully proven technology with plants operating for over ten years, including a 290 MW plant in Huntorf, Germany (1978) and a 110 MW plant in McIntosh, Alabama (1991). These plants provide a variety of functions, including spinning reserve, load management, peaking power, and power factor control.

Principles of Operation

Unlike other storage technologies, an external fuel source such as natural gas is used to preheat the cooled, high-pressure air before it enters the expansion stage. In effect, CAES is a gas turbine with the compressor and expander operating independently and at different times. The approach offers significant advantages over conventional simple-cycle combustion turbines, where approximately 55-70% of the expander power is used to drive the compressor. The concept is illustrated in Figure 2-8.

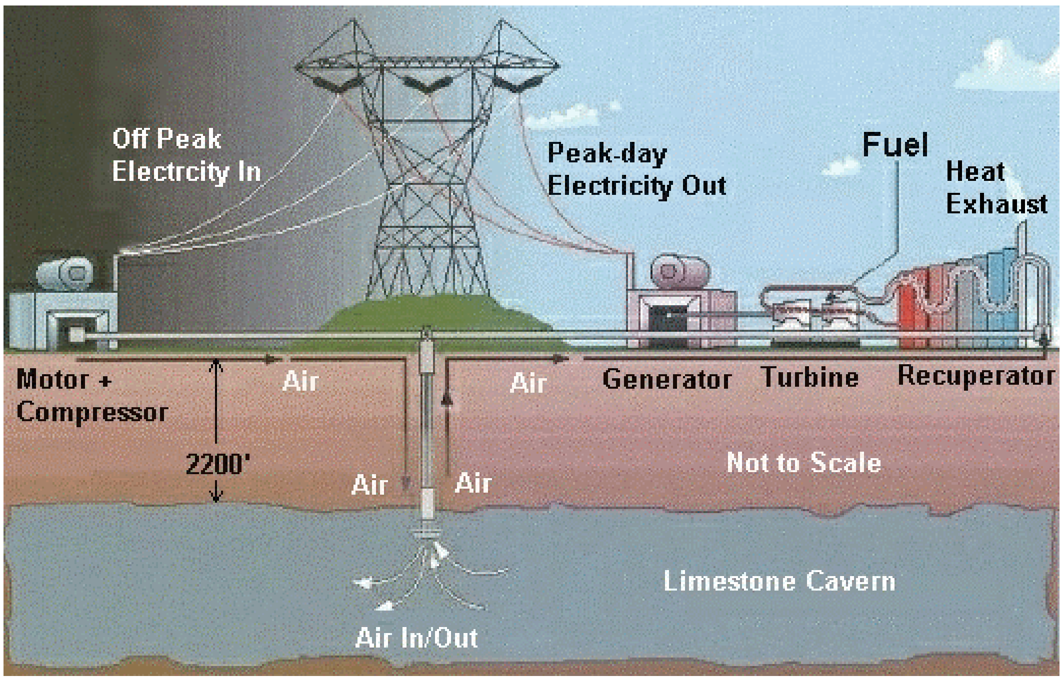

Figure 2-8
CAES Storage Concept

For power plants with energy storage in excess of 20 MWh, air is stored underground in salt caverns, hard rock caverns, or porous rock formations. Siting these plants therefore requires the presence of suitable geological formations. For smaller systems, however, above ground storage in gas pipes or pressure vessels may be employed, and these are not constrained by geology.

Conventional CAES plants use a motor/generator with clutches on both ends that allow it to engage/disengage the compressor and expander. Compression is normally performed in multiple stages with intercoolers (to reduce power consumption) and an aftercooler (to reduce the storage volume). The expansion train consists of high- and low-pressure turboexpanders with combustors between stages.

Compressed air that is withdrawn from the storage reservoir is preheated in a recuperator and may be further heated in a combustor, and then expanded through the reheat turboexpander train. The combustor, which can be designed to operate on a variety of fuels, allows the plant to deliver 30-35% more energy to the grid during generation than it consumes during compression. By virtue of the energy stored in the compressed air, the expansion turbine provides 2 to 3 times more power than an equivalent turbine in a simple-cycle combustion turbine plant.

Variations on the conventional CAES thermodynamic cycle include (1) the recuperated cycle which recovers turbine waste heat to preheat air before combustion); (2) the combined cycle which employs a heat recovery steam generator that drives a bottoming cycle; (3) the steam-injected cycle which injects steam into the air to increase mass flow before expansion; (4) humidification of the air before expansion which also increases mass flow; and (5) the adiabatic cycle which recovers and stores thermal energy from the compression cycle to later reheat the air during generation.

A recuperated cycle is illustrated in Figure 2-9. A recuperator recovers the low-pressure turbine waste heat to preheat the stored air before it goes into the high-pressure combustor. This reduces the fuel consumption of the plant (as compared to the conventional plant above) by about 25%. This configuration was used in the McIntosh plant that was designed for primary operation as a source of peak power and as a load- management storage plant. The recuperator is a necessary component to reduce costs of the peak power.

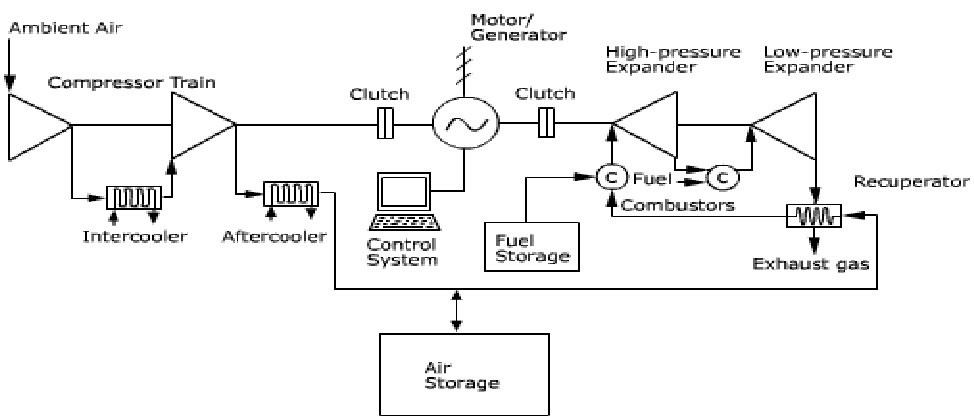

Figure 2-9
CAES Recuperated Cycle

Footprint

Underground air storage, whether provided by natural caverns or buried pipe, do not preclude the use of the surface for other activities. Therefore, only the above ground plant is included in footprint estimates, typically about 1 acre for a 100 MWe plant.

Maintenance Requirements

The maintenance is the same as a simple cycle combustion turbine, about $0.30/MWh generated.

Life

The life is comparable to a combustion turbine plant, about 30 years.

Efficiency

CAES plants deliver about 75% of the energy used to compress air in the off-peak hours. Losses include pipe friction, air leakage, pressure regulation, and compressor/expander component efficiencies. Fuel consumption is treated separately as an operating cost, and the energy content of the fuel is not included in this efficiency value.

Response Time

If a CAES plant is operated as a hot spinning reserve, it can reach the maximum capacity within a few seconds. The emergency startup times from cold conditions at the Huntorf and McIntosh plants are about 5 minutes. Their normal startup times are about 10 to 12 minutes. CAES plants have a ramp rate of about 30% of maximum load per minute.

Environmental Impact

Environmental impact is comparable to combustion turbine (CT) technology. The primary concern is air emissions. NO_x discharged from CAES plants can be less than 5 ppm as in conventional CTs.

Field Experience

Two CAES plants are currently in operation, with operating experience of over 10 years. The Huntorf plant was the first compressed air storage power station in the world. It began commercial operation December 1978. E.ON Kraftwerke of Bremen, Germany owns the 290-MWe CAES plant in Huntorf, Germany. ABB (formerly BBC) was the main contractor for the plant. The compressed air is stored in two salt caverns between 2,100 and 2,600 feet below the surface with a total volume of 11 million cubic feet. The caverns have a maximum diameter of about 200 feet and a height of 500 feet. The cavern air pressure ranges from 620 to 1,010 psi. At the compressor airflow rate of 187,000 scfm (108 kg/s), the plant requires 12 hours for full recharge. At full power, the turbine draws 720,000 scfm (417 kg/s) of airflow from the caverns for up to 4 hours. After that, the cavern pressure is too low to allow generation at 290 MWe and the airflow supplied by the caverns decreases (although the plant will produce power at an exponentially declining power level for over 10 hours).

The 110-MWe McIntosh plant, owned by the Alabama Electric Cooperative, is the second CAES power plant in the world. Dresser-Rand designed and constructed the turbomachinery train. The overall plant (turbomachinery, building, and underground cavern) was constructed in 30 months for a cost $51 million (1991 dollars) and was completed on June 1, 1991. The air is compressed in three stages, each followed by an intercooler. The compressed air is stored in a salt cavern between 1,500 and 2,500 feet below the surface with a total volume of 22 million cubic feet, yielding a power generating duration of 26 hours at full power and at 267,000 scfm (340 lb/s). The cavern air pressure ranges from 650 to 1,080 psi during normal operation. The reheat turboexpander train has high- and low-pressure expanders with high and low pressure combustors and drives the electric motor/generator to produce peak electric power. Duel-fuel combustors are capable of burning natural gas or fuel oil. An advanced recuperator is used to extract thermal energy from the low-pressure expander exhaust to preheat inlet air from the storage cavern before it goes to the inlet of the high-pressure combustor. The recuperator reduces fuel consumption by approximately 25%.

Capital and Operating Costs

Table 2-9 shows the typical capital cost per kW_e for hypothetical CAES plants designed for T&D applications using various storage media. The fixed O&M costs for CAES plants are projected to be in the range of $4/kW-yr to $7/kW-yr, and the variable O&M costs in the range of $0.001/kWh to $0.002/kWh. In these examples, the fixed and variable O&M costs, the electricity in vs. out, and the heat rate were chosen to be the same for every plant:

- Fixed O&M costs $6.00/$kW_e$ per year
- Variable O&M costs $0.002/kWh
- Electric Input/Output 0.75
- Heat Rate (HHV Btu/kWh) 4,000

Table 2-9
CAES Pant Capital Cost

Storage Media for CAES Plant	Size (MW_e)	Cost for Power-Related Plant Components ($/kW)	Cost for the Energy Storage Components ($/kWh)	"Typical" Hours of Storage for a Plant	Total Cost ($/$kW_e$)
Salt	200	350	1	10	360
Porous Media	200	350	0.10	10	351
Hard Rock (new cavern built for plant)	200	350	30	10	650
Surface Piping	20	350	30	3	440

Flywheels

Advanced flywheel energy storage systems utilize a broad range of new technologies including carbon composite rotors, magnetic bearings, and efficient inverters and rectifiers. These devices are "charged" and "discharged" either mechanically by a physical couple to a power shaft or electrically through a motor/generator.

Principles of Operation

Central to the flywheel is the rotor itself, which stores kinetic energy in an amount determined by its moment of inertia (its "rotational mass") and its maximum design speed of rotation. Rotors may be oriented with either horizontally or vertically (Figure 2-10), and are designed to maximize energy density while maintaining structural integrity in the face of rotational and thermal stresses. Low-speed rotors, made of conventional heavy materials such as steel, are limited in rim speed but have obvious cost advantages, while high-speed rotors use more exotic materials such as graphite composites and fiberglass. These materials are lighter but stronger and allow much higher rotational speeds, between 10,000 and 100,000 rpm.

Low-Speed Horizontal-Shaft Steel Flywheel
(Courtesy of Satcon Power Systems)

High-Speed Vertical-Shaft Composite Power Flywheel

Figure 2-10
Sample Flywheels and Shaft Orientations

Flywheel bearings support the rotor by constraining five of the six degrees of freedom for rigid bodies, allowing only rotation around the axis of the rotor. Flywheel speed is limited in large part by the friction on the bearings, and the resulting wear on the bearings often defines the maintenance schedule for the system. Mechanical bearings such as sleeve and roller bearings are inexpensive and reliable but produce frictional forces that limit speed of rotation and reduce efficiency. In high-speed flywheels, higher performance advanced magnetic bearings are used to reduce or eliminate friction. Passive magnetic bearings are simply permanent magnets that support all or part of the loads. Active magnetic bearings use controlled magnetic fields in which field strength on the bearing axes is dynamically varied to counter the effects of external forces on the rotor. Superconducting bearings are passive bearings that use superconducting materials in producing the magnetic repulsive support forces.

Motor/generators convert electrical energy into rotational mechanical energy stored in the flywheel rotor during charge and recoup this energy during discharge. The machine consists of a wound or permanent magnet rotor, usually revolving within a stator containing electrical winding through which charge and discharge currents flow. The motor/generator is sized according to the power requirements of the application. The motor/generator and other flywheel components are illustrated in Figure 2-11.

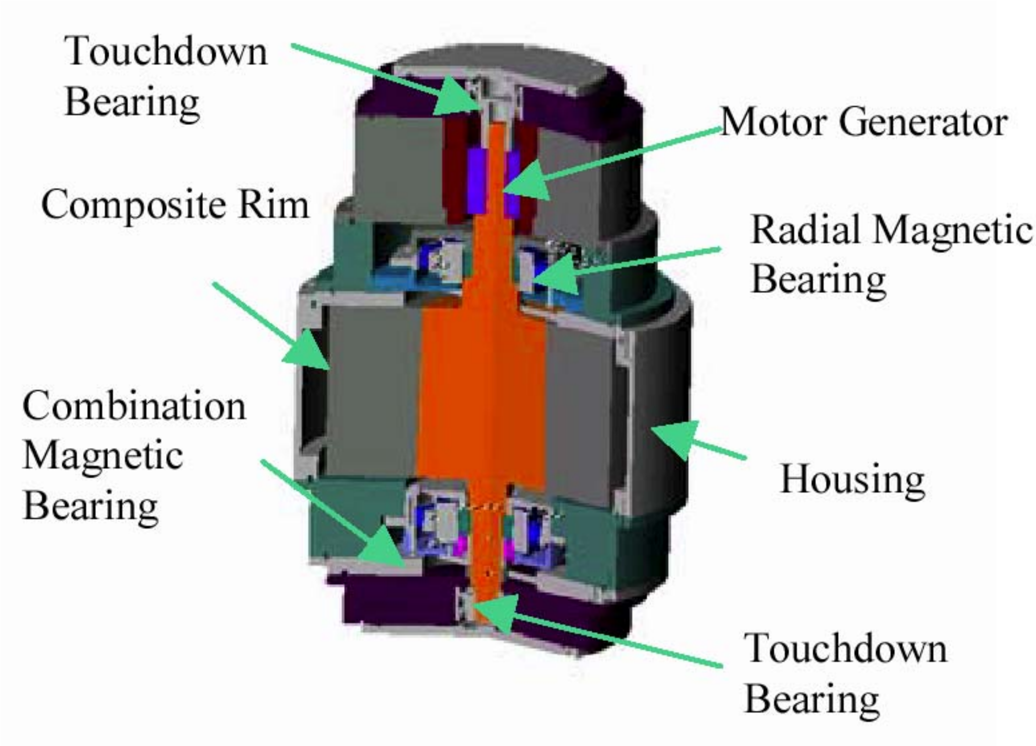

Figure 2-11
Cross-Section of a Flywheel Module (Courtesy NASA Glenn Research Center)

Flywheels systems must incorporate some way to bridge the varying frequency of the motor generator and the fixed frequency of the utility grid. In some cases, this is accomplished using electromechanical methods, such as the eddy-current clutch and induction coupling, but in most cases rectifiers and inverters are used in which the bridge is provided by a DC bus. System power ratings are constrained by the current carrying capability of the power electronics that becomes critical near the rotor low-end cutout speed (output current is normally proportional to load and inversely proportional to speed).

Containment vessels, usually made of thick steel surrounding all rotational components, provide safety and enhanced system performance. In the event of catastrophic failure, the containment vessel stops or slow parts and fragments, preventing injury to bystanders and damage to surrounding equipment. The containment vessel is often placed under vacuum or filled with a low-friction gas such as helium to reduce the effect of friction on the rotor.

Footprint

A prototype flywheel installation for voltage control at a New York City Transit (NYCT) site consists of ten individual high-speed flywheels of 100 kw each, connected together to provide 1 MW capacity. Together the flywheels store about 5 kWh in kinetic energy. This installation is capable of meeting the footprint requirement of 100 kW/m^2.

Maintenance Requirements

Annual maintenance is required for inspections and scheduled component replacements.

Life

In flywheel systems there is at least one moving part, the rotor itself. The most important life-limiting parts are the bearings on which the rotor rests. Continuous operation of a flywheel, even if it is not cycled, will eventually lead to deterioration of these bearings. Some designers have attempted to mitigate this life-limiting issue by either augmenting or entirely replacing mechanical bearings with magnetic bearings.

Flywheels generally exhibit excellent cycle life in comparison to other energy storage systems. Most developers estimate cycle life in excess of 100,000 full cycles. The rotor is subject to fatigue effects due to the cyclical application and stress during charge and discharge. The most common failure mode for the rotor is the propagation of cracks through the rotor over a period of time. Crack propagation can be difficult to detect in steel rotors, and hazardous failure modes are possible in which large chunks of steel break off from the rotor during operation.

In graphite rotors, cracks tend to propagate longitudinally, or result in de-lamination of the concentric layers of material. This phenomenon causes the rotor to gradually deviate from normal operation, ensuring that the abnormality is easily detected, thus allowing the device to be removed from service before a hazardous failure mode occurs.

Efficiency

Energy depends on mass and rotational velocity. High RPM, sometimes considered a measure of technical sophistication, is only part of the equation for high energy. For flywheels, the important parameter is rotational velocity or rim surface speed, which is circumference times RPM. For example, a small 0.5 kWh flywheel has a relatively small diameter rotor and may spin at 100 kRPM; whereas a heavier 6 kWh flywheel has a bigger diameter rim and maintains the same rim surface speed at only 20 kRPM. Therefore flywheel systems designed for high energy as oppose to high power tend to be larger diameter, taking advantage of weight and rim speed.

Round-trip efficiency and standby power loss become critical design factors in energy flywheel design, whereas they are largely irrelevant in power flywheel design. For these reasons, energy flywheels require more advanced technologies than power flywheels. These energy flywheels usually have composite rotors enclosed in vacuum containment systems, with magnetic bearings. Such systems typically store between 500 and 10,000 Whr. The largest commercially available systems of this type are in the 2-6 kWh, with plans for up to 25 kWh.

Round-trip efficiency for energy flywheels is between 70 and 80%. The standby losses are very small, typically less than 25W per kWh of storage and in the 1-2% range.

Response Time

In the NYCT prototype system described above, the system could be expected to operate as often as every 2 minutes during peak transit hours, and average about every 6 minutes during normal operating hours. A complete cycle of the flywheels consist of a 20 second discharge triggered by reduced voltage during train accelerations and a recharge at approximately the same rate if regenerative trains are breaking in the vicinity. Otherwise the recharge is controlled based on track voltage during the several minutes between trains. The power control for the system is based on the dc-track voltage. By controlling the power electronics the system can provide zero to maximum power in 5 milliseconds.

Environmental Impact

In contrast to many other energy storage systems, flywheel systems have few adverse environmental effects, both in normal operation and in failure conditions. Neither low-speed nor high-speed flywheel systems use hazardous materials, and the machines produce no emissions. The most important environmental constraint for flywheel systems is noise when in operation. Many large flywheel systems, especially low-speed systems, are quite loud, often reaching noise levels in excess of 70 dB at 6 feet. On the other hand, high-speed systems with vacuum containment are considerably quieter, and those that are installed underground can be unnoticeable.

Field Experience

Flywheels are commercially available by multiple suppliers. Most suppliers have focused their efforts on the power conditioning market and have adopted conservative designs incorporating steel wheels operating at low rotational speeds. These systems typically provide 100 to 500 kW for periods ranging between 5 and 50 seconds. Ongoing development with advanced flywheel technologies is directed at improving performance, establishing high reliability, and reducing costs.

Capital and Operating Costs

Costs for two flywheel applications are presented in Table 2-10 for low-speed, high-speed, and advanced “increased capacity” flywheel systems. The traction load application is used for the applications analysis in this assessment.

Table 2-10
Flywheel Suppliers and Product Characteristics

AFS Trinity	M3A	Graphite Composite	40,800	Vacuum	Active Magnetic	100	15 sec	15 sec	0.70%
Beacon Power	SmartEnergy BHE-6	Graphite Composite	22,500	Vacuum	Active Magnetic	2	3 hrs	2.5 hrs @ 4kW	3.5%
Hitec (formerly Holec)	Continuous Power Supply (CPS)*	Steel	3,600	Air	Mechanical	275 - 2000 kVA	10 sec	10 sec	2.5%
Pentadyne	PPC 120	Graphite Composite	55,000	Vacuum	Active Magnetic	120	20 sec	20 sec	0.10%
Piller	Powerbridge	Steel	3,600	Helium	Magnetic	1100	15 sec	60 sec	4.5%
SatCon	Starsine Rotary UPS*	Steel	1,800	Air	Mechanical	315 - 2200kVA	12 sec	12 sec	2.3%
Urenco Power Technologies	pq250	Graphite Composite	36,000	Vacuum	Magnetic	250	30 sec	26 sec	0.28%

[1] Where rated power is a range, the maximum power is used for this calculation
[2] Generator system with integrated flywheel

Table 2-11
Capital O&M Costs for Sample Flywheel Installations

Technology Variant	T&D Application	Size* MW	Stg Capacity kW-hours	A. Power Related Capital Cost	B. Energy Related Capital Cost	C. Installation Related Capital Cost	Total Capital Cost (A + B+ C)	Annual Estiamated O&M Cost
Low Speed Flywheel	AC Grid Stability	1.5	5.00	$389,603	$119,878	$104,567	$614,048	$67,447
Low Speed Flywheel ($/kw)	AC Grid Stability	1.5	5.00	$260	$80	$70	$409	$45
High Speed Flywheel	Traction Load Fluctuations	1	8.33	$409,500	$220,500	$105,000	$735,000	$66,398
High Speed Flywheel ($/kw)	Traction Load Fluctuations	1	8.33	$410	$221	$105	$735	$66
Increased Capacity High Speed Flywheel	Traction Load Fluctuations	1	8.33	$189,000	$231,000	$63,000	$483,000	$50,320
Increased Capacity High Speed Flywheel ($/kw)	Traction Load Fluctuations	1	8.33	$189	$231	$63	$483	$50

*Note: Multiple flywheel systems can be connected in parallel to produce a larger size flywheel system. For example, for some applications, multiple 250kW flywheel units might be a better technically feasible system than on single 1.5MW unit.

Electrochemical Capacitors

Capacitors are classified as either electrostatic, electrolytic, or electrochemical according to the means of storing electric charge. The electrostatic capacitor, including the familiar parallel-plate capacitor, is created from two conductors that are separated by an insulator, such as paper. The electrolytic capacitor, made of two capacitors in series connected by an electrolyte, achieves much thinner plate separation than the paper or film dielectrics in electrostatic capacitors. Energy is stored across an oxide dielectric layer on a roughened metal surface. The electrochemical capacitor, sometimes referred to as the electric double layer capacitor, supercapacitor, or ultracapacitor, stores energy by charge separation at the interface between a solid electrode and an electrolyte. It is the electrochemical capacitor, (Figure 2-12) due to its very high energy density, that is the subject of this analysis.

ECaSS commercial capacitors, from left, Nissan Diesel (346Vdc, 35F, 6.3Wh/kg), Shizuki Electric Faradcap (FML-2A, 54V, 75F, 30Wh), PowerSystems (HO2A, 54V, 65F, 6.5Wh/kg).

Figure 2-12
Example Commercial Electrochemical Capacitors

Principles of Operation

The electrochemical capacitor is comprised of two double layer charge storage surfaces in series, i.e. two electrostatic capacitors in series. Each of the two surfaces is formed at the interface between a conducting electrode and the electrolyte. When a voltage is imposed across them, there is an increase in electrolyte ion concentration and a change in electrolyte ion orientation near the surface of the electrode. Charge separation at this interface occurs over a very short distance, ~10 angstroms. If a high surface area conductor such as activated carbon is used, extremely large capacitance values, on the order of 100 Farads per gram of material, can be obtained.

"Asymmetric" capacitor designs use different materials for the two electrodes with one of the electrodes having much higher capacity than the other. This arrangement provides greater energy and power density advantages over "symmetric" designs having both electrodes of the same material and approximately the same mass. This is due to the series arrangement of the two surfaces, where 1/C total = 1/C1 + 1/C2. Total device capacitance in symmetric design is limited to only about half that of each electrode C1 and C2.

Although the double layer phenomenon has been known for more than 100 years, the first practical device was created in the late 1960's. Early electrochemical capacitors ("type I" devices) were of symmetric design having two activated carbon electrodes with sulfuric acid or potassium hydroxide electrolyte. Later designs ("type II"), which can operate at higher voltages due to their organic electrolyte, are the most common electrochemical capacitors in use today. Asymmetric designs have been introduced more recently ("type III"), with one activated carbon electrode, one high capacity electrode, and an aqueous electrolyte. Commercial type II capacitors range in size up to hundreds of thousands of Farads and energy densities of around 10 Wh/kg. Development of advanced designs with various asymmetric couples is ongoing.

Footprint

A conceptual design for a 300 kVA substation ridethrough application (providing power during the transition to a standby generator) has been developed. The capacitor could be designed to a footprint of 50 kW/m^2. The system would deliver 50 kWh over 15 seconds.

Maintenance requirements

Routine maintenance includes checking capacitor connections and adjusting and tuning the system.

Life

Type III electrochemical capacitors have a life of about 100,000 complete discharge cycles.

Efficiency

The energy used by the electrochemical capacitor system to maintain the capacitors and controls is a function of the system efficiency and duty cycle. For example, for some applications, the duty cycle might be once per week, while for more demanding applications, the duty cycle might be once per hour. The efficiency is greatest for light duty cycle applications and typically reaches 96 percent. However, for high duty cycle applications, the efficiency typically reduces to 90 percent.

Response Time

The capacitor is capable of meeting the response time of the power ride-through application of 5 milliseconds.

Environmental Impact

There are presently no recycling programs for any electrochemical capacitors. There is no motivation to recycle symmetrical products because they contain little high-value material. Proper disposal may be an issue for type II products containing acetonitrile because this solvent is classified as a toxic material for waste reporting purposes. Type III products contain high value and reclaimable nickel, very much like the nickel used in nickel metal hydride and nickel cadmium batteries. There are well-established programs for recycling these nickel-containing batteries. It is possible that recycling of the battery-like, electrode could be accommodated into these programs, once the capacitor product comes into widespread use. The carbon electrodes and aqueous electrolyte in these capacitors present no specific disposal issues.

Field Experience

There are a number of manufacturers producing large electrochemical capacitors on a commercial basis. Typical products are described in Table 2-12.

Capital and Operating Costs

Capital and O&M costs are presented in Table 2-13 for two storage applications. The standby UPS application was used as the basis for the analysis in this report.

Table 2-12
Electrochemical Capacitor Suppliers

Manufacturer	Country	State of the Technology	Typical Energy Storage and Voltage Ratings	Technology type
ECOND	Russia	commercial products	50 kJ, 200 V	type I
Elit Joint Stock Company	Russia	commercial products	50 kJ, 400 V	type I
EPCOS AG	Germany	commercial products	20 kJ, 2.5 V	type II
ESMA Joint Stock Company	Russia	commercial products	125 kJ, 1.6 V	type III
Maxwell Technologies, Inc.	USA	commercial products	8 kJ, 2.5 V	type II
NESS capacitor Company	Korea	commercial products	16 kJ, 2.5 V	type II
NEC Tokin	Japan	development	3 kJ, 2.4 V	type I
Okamura Laboratory, Inc. (ECaSS)	Japan	commercial products	5 kJ, 2.7 V	type II
Panasonic	Japan	commercial products	5 kJ, 2.3 V	type II
SAFT	France	advanced prototype	10 kJ, 2.5 V	type II

Table 2-13
Capacitor Capital and O&M Costs

Technology	T&D	Size*	Stg kW-	A. Related Cost	B. Related Cost	C. Related Cost	Total Cost (A + C)	Annual Estiamate O&M
Pulse Type II or III	Mini FACTs Controlle	3	1.67	$270,00	$180,00	$180,00	$630,00	$87,62
Pulse Type II or III	Mini FACTs Controlle	3	1.67	$90	$60	$60	$210	$29
Traction Type Capacitor	Standby UPS Substatio	0.25	1.04	$75,00	$75,00	$27,00	$177,00	$87,62
Traction Type III Capacitors	Standby UPS Substatio	0.25	1.04	$300	$300	$108	$708	$351

*Note: Capacitor modules are connected in series to achieve the operating votlage and in parallel for current boost converter to achieve the higher voltages needed for distribution

3
TECHNOLOGIES SUMMARY

The six technologies are summarized in the following three tables, using data provided in the EPRI Energy Storage Handbook (EPRI, 1007189). Table 3-1 shows the status of each technology, the current development trends, and commercialization issues. Table 3-2 provides an overview of the performance characteristics of each technology. Table 3-3 is a summary of reported capital and O&M costs for selected applications.

Table 3-1
Technology Status

Technology	Status	Development Trends/Plans	Issues
NAS	Early commercial 20 demonstration projects above 500 kW (largest 6 MW x 8 h) 30 projects below 500 kW	Commitment to manufacture 1000 modules per year starting in 2003 Worldwide marketing	Competitiveness, certification (outside Japan)
PSB	Pre-commercial 2 major demonstration projects under construction: (1) 15 MW x 8 h; and (12 MW x 10 h)	Target market 100 MWh, 10 MW or larger	Sustained financial commitment of Innogy/RWE Difficult to change target markets if required
VRB	Pre-commercial 7 major demonstration projects ranging from 30 kW to 1500 kW and ranging from 1 h to 8 h of discharge duration.	Market expansion worldwide Larger, scaled up systems Standardized product lines	Systems not safety or performance certified (e.g., UL listing) Long term cycling experience lacking Large footprint Little ongoing maintenance experience
CAES	Mature technology Two operating plants: 290 MW_e Huntorf, Germany (1978), spinning reserve; and 110 MW_e McIntosh, Alabama (1991), multiple functions	Norton Plant (2700 MW, Ohio) project underway; first 300 MW expected online in 2003 Matagordo Plant (540 MW, Texas) in development	Lowest cost alternatives require suitable geology Ramp rate limitations 3-year lead time typical
Flywheel	Commercial (power quality applications) Pre-commercial (utility applications)	Most manufacturers pursuing PQ market and hybrid systems for ride-through Some development on long duration (hours) flywheels	Bearing technology: passive and superconducting bearings in development Improved rotor materials in development
Electrochemical Capacitor	Commercial products available from multiple manufacturers	Improved capacitor design, manufacturing cost reductions, and electrode materials development Capacitor thermal management	High cost, especially electrode materials Reliability of high-voltage strings Toxicity and safety issues

Table 3-2
Technology Attributes

Technology	Discharge Duration	Response Time	Roundtrip Efficiency	Footprint	Life	Maintenance
NAS	Seconds to 10 hours, depending upon application	Milliseconds	70-75%	15-60 m^2/MWh, depending upon design	Module life 10-15 years	3-year inspections 1000 cycles adjust module vacuum
PSB	4-10 hours	Milliseconds Would be similar to VRB if stack were not primed	60-65%	100 m^2/MWh (100 MWh plant)	Stack life 10-15 years	3-month inspections Repairs of mechanical components Crystalline sodium sulfate collected and disposed every two weeks
VRB	4-10 hours	Milliseconds (with stack primed) Minutes (without stack primed)	70%	110 m^2/MWh (10 MWh conceptual plant design)	Stack life 10-15 years at 100 cycles per year	Little field experience Annual inspections Pump bearings and impeller seals replaced about every five years
CAES	4-30 hours	1 second to 15 minutes, depending upon application	75-85% Heat rate 4,000 Btu/kWh	40 m^2/MWh typical (not including underground storage reservoir)	30 years	Same as simple cycle combustion turbine: about $0.30/MWh generated
Technology	**Discharge Duration**	**Response Time**	**Roundtrip Efficiency**	**Footprint**	**Life**	**Maintenance**
Flywheel	Seconds to minutes	Milliseconds	70-80% 25 W/kWh standby losses	10 m^2/MW (Traction Load Fluctuations)	100,000 cycles	Annual inspections Periodic component replacement
Electrochemical Capacitor	Seconds	Milliseconds	90-97%	20 m^2/MW (Substation ride-through)	100,000 cycles	Annual inspections Periodic component replacement

Table 3-3
Projected Mature Technology Costs

Technology	Sample Application	Plant Size (MW)	Plant Capacity (MWh)	Capital Cost – Power Related ($/kW)	Capital Cost – Energy Related ($/kWh)	Heat Rate (Btu/kWh)	O&M Cost – Fixed ($/kW-yr)	O&M Cost – Variable ($/kWh)
NAS	Load-Leveling	10	72	250	192	N/A	9.0	12.4
	Power Quality Protection & Grid Support	10	0.42	300	7,305	N/A	6.6	8.8
	Automatic Generation Control	26	26	300	585	N/A	7.2	10.0
	Wind Farm Stabilization	2	14.4	300	192	N/A	9.0	7.5
PSB	Transmission Deferral & Regulation	10	100	150	65	N/A	1.0	0.005
VRB	DR/Peak Shaving	1	4	500	150	N/A	2.0	0.029
	Spinning Reserve	10	20	426	250	N/A	0.2	0.029
	Windfarm Stabilization & Dispatch	10	80	426	100	N/A	0.2	0.029
CAES	Peak Shaving (salt cavern)	20	60	350	1	4,000	6.0	0.002
	Energy Imbalance / Area Control (salt cavern)	200	50	350	1	4,000	6.0	0.002
	Spinning Reserve (above ground)	200	50	350	30	4,000	6.0	0.002

	Supplemental Reserve (salt cavern)	200	100	350	1	4,000	6.0	0.002
	Arbitrage (natural porous rock)	200	2,000	350	0.10	4,000	6.0	0.002
Flywheel	Low speed / AC Grid Stability	1	0.005	409	N/A	N/A	45.0	0
	High speed / Traction Load Fluctuations	1	0.008	735	N/A	N/A	66.0	0
Capacitor	Pulse Type II or Type III / Mini FACTs Controller	3	0.002	210	N/A	N/A	29	0
	Traction Type III / Standby UPS for Substation	0.25	0.001	708	N/A	N/A	350	0

4
APPLICATIONS OVERVIEW

The technologies considered in this analysis include two general classes of storage alternatives: (1) "long term" – hours of storage, provided by the CAES, PSB, VRB, and NAS technologies; and (2) "short term" – minutes of storage, provided by the flywheel and electrochemical capacitor technologies. These two alternatives serve different applications as illustrated in four DR applications:

- **Peak Shaving - Customer Ownership**. Long-term storage systems installed on the customer side of the meter save demand charges on the utility bill. These systems charge during off-peak periods and discharge according to a dispatch strategy that minimizes the billed monthly peak load. Such a system can also provide energy savings and improved power factor.
- **Peak Shaving - Utility Ownership**. Similar to the customer ownership scenario, peak shaving can be provided by storage technologies owned and operated by the utility. With a transportable storage system, T&D deferral benefits can be provided at multiple sites over the life of the system.
- **Power Carryover**. The short-term storage technologies can provide enhanced reliability at the customer site by providing "ride-through" during momentary utility outages or transition to stand-by generation. Benefits relative to conventional UPS systems include improved efficiency ("in-line" versus "off-line"), reduced heat removal loading, and building footprint savings.
- **Hybrid Off-grid Systems / Microgrids**. Storage can supplement a fuel cell or diesel generator to provide load following service and enhanced generator efficiency (full load versus part load). There are potential savings in operating costs as well as capital investment due to size optimization of the generator. The storage system can also help support the microgrid voltage.

Cost and performance data is taken fro all applications from the EPRI Energy Storage Handbook (EPRI, 1007189). Mature cost figures are used to illustrate the potential of each technology.

5
PEAK SHAVING—CUSTOMER OWNERSHIP

Application Requirements

Energy storage systems may be used by commercial and industrial customers to lower costs of electric utility bills. The most significant portion of bill savings would be in the form of lower demand charges, but the system would also provide energy savings – by using low cost power from off-peak periods to displace high-cost power during peak periods – and in some cases savings in charges due to reduced reactive power consumption (i.e., the system would improve power factor). These benefits are offset by the capital cost of the storage equipment and recurring maintenance and operating costs such as electricity used for charging.

For this application, the energy storage system would be located on the customer premises and installed on the customer side of the meter. The system would be electrically connected to the power distribution panel at the customer service entrance, and would have to meet all utility interconnection requirements parallel generators, such as protective relays and disconnect switches to isolate the system as necessary. The system would be sized according to historical power and energy consumption, typically obtained by reviewing past utility bills.

Systems must physically fit within available space at the facility, but this is a highly case specific. In some cases, systems would be installed outside the building and space requirements are not an issue. In other cases, useful space represents a cost to the customer (for example, as an opportunity cost in foregoing revenue-producing activities) or the site may simply be physically constrained. In these cases, footprint could be the deciding factor as to whether storage is feasible or not. For these reasons, it is difficult to assign a quantitative value for maximum technology footprint.

Reliability must be good, but this is not a critical factor since system outages would only result in lost bill savings for a given month. In the worst case, a system failure would coincide with the peak demand for the month, and the customer would loose the demand charge savings for that month.

Likewise, response times are not critical. Monthly peak demand is normally measured in increments of 15 minutes or 30 minutes, so a 5-minute response time would probably be adequate. This is sufficient to allow the flow batteries or CAES technologies to be kept idle for performance savings, e.g., the pumps of the VRB could be powered down during all but the charging and discharging periods.

Roundtrip efficiency should be around 60-70% or better, which would roughly balance the energy cost of charging with the benefit of discharging. For example, if on-peak energy charges (for a large industrial customer) were \$0.05/kWh and off-peak charges were \$0.035/kWh, the system would have to be 70% efficient to break even. Higher efficiencies result in higher energy benefits to the customer.

Finally, the system must include a control system that provides some means of dispatching the battery. If the loads were predictable, dispatch decisions could be made according to the time of day, so that the charging would take place during off-peak periods and discharging would take place during on-peak periods as defined by the utility tariff. A better approach would be to measure the load at the meter and dispatch energy according to the real time load above a load "setpoint" or threshold. A more advanced control system might take into account the real-time state of charge, perform load forecasting based on historical load profiles, and optimize the setpoint every hour.

Storage Technology Comparisons

Three of the storage technologies are included in this application assessment: NAS, VRB, and CAES. Flywheels and capacitors are not included due to their short discharge duration. In the case of the PSB, there are no technical reasons that would preclude its use in customer sited peak shaving, however the storage requirements are much smaller than those Innogy is pursuing commercially. The example case is 4 MWh that corresponds to a typical industrial customer, and even much smaller systems down to about 50 kWh would be relevant. Innogy declined to participate in a previous 10 MWh project due to size considerations.

Each technology is differentiated according to capital costs, O&M costs, and roundtrip efficiency. For the NAS battery, power- and energy-related capital costs were taken based upon reported "peak shaving" costs for a 10 MW / 70 MWh system using modules optimized for this application. These were therefore scaled linearly with size, and no changes were made to the reported costs. These variable O&M costs were assumed to be zero since the reported values represented the cost of electricity for module heating and PCS "hot" standby. However, these loads were also included in the efficiency for load leveling applications (75.8%), and the methodology accounts separately for the cost of electricity.

VRB capital and operating costs were taken directly from the 1 MW / 4 MWh application case study, as was the round-trip efficiency.

It is unclear whether the CAES technology would be applicable to a system of this size. Costs were reported for a 20 MW / 3 hour system. Nonetheless, it is certainly possible to design such a system using "surface piping" technology, and the costs were taken from this method of compressed air storage. As with the NAS battery, capital costs were scaled linearly. Fixed O&M costs were reported as $4-7/kW-yr, and the analysis used the upper bound. "Electric input/output" is reported as 0.75, which includes the ratio of generated electricity to purchased electricity and the energy lost to pipe friction, air leakage, pressure regulation, and compressor/expander component efficiencies, i.e., the round trip efficiency excluding fuel consumption. The heat rate was reported as 4,000 (HHV Btu/kWh), and average monthly retail natural gas prices 2002 were $4.38 per thousand cubic feet for industrial consumers in Wisconsin[2], the location of the case study. Therefore, fuel costs are calculated as $4.38/kft3 x (1 kft3/1000 ft3) x (1 ft3/1041 Btu HHV) x (4000 HHV Btu/kWh) = $0.017/kWh. This is the only component of variable O&M costs.

Study assumptions used for all technologies in the analysis are shown in Table 5-1.

[2] Prices from 2001 were not used since they were excessively high due to short term perturbations in the energy markets. Prices are taken from *Average Price of Natural Gas Sold to Industrial Consumers, by State, 2000-2002*, Energy Information Administration.

Table 5-1
Case Study Assumptions for Customer Peak Shaving

Assumption	NAS	VRB	CAES
Energy rating (kWh)	4,000	4,000	4,000
System rating (kW)	1,000	1,000	1,000
Round Trip Efficiency	0.758	0.70	0.75
Capital Cost - Energy Related ($/kWh)	192	150	30
Capital Cost - Power Related ($/kW)	250	500	350
O&M - Fixed ($/kW-yr)	9	2	7
O&M - Variable ($/kWh)	0	0	0.017

Modeling and Analysis

The primary economic figure of merit used by commercial entities in evaluating investment opportunities – and the basis for technology comparisons in this analysis – is the internal rate of return (IRR). Therefore, the objective of the methodology is to calculate the IRR by considering the after-tax cash flow over the life of the system.

The methodology is closely tied to the utility tariff structure, and the benefits are determined by estimating the monthly savings in the utility bill. There are wide variations of tariffs, but for industrial customers they generally include fixed charges, charges for energy (kWh) and peak monthly demand charges (kW). Tariffs often include other elements, such as energy or demand tier pricing, time of use, power factor correction, fuel cost adjustments. For purposes of this analysis, a relatively complicated (and comprehensive) tariff is used so that it can be easily adapted to most other tariffs by selecting different user-input values.

The case study is based on the "General Primary Service - Time of Use" tariff available to industrial customers in the service territory of Wisconsin Electric Power Company, known as "We Energies." The particular case is based upon a voltage service class of 12,470 to 138,000 volts. This tariff is described in Table 5-2.

The customer demand charge is applied to the maximum demand over the previous 12 month period. The on peak demand charge is applied to the peak demand measured in the billing month. There are two fixed charges, one taxable and one not taxable. The tariff also includes on-peak and off-peak energy charges, and fuel cost adjustments for demand, on-peak energy, and off-peak energy. Finally, the tariff includes a charge that applies when power factor during the peak demand is outside the range of 0.85 leading to 0.85 lagging.

Table 5-2
We Energies General Primary Service - TOU Tariff

Customer Demand Charge ($/kW-mo)	0.76
On Peak Demand Charge ($/kW-mo)	8.36
Facilities Charge ($/mo)	525.00
Ton-taxable Customer Charge ($/mo)	102.00
On Peak Energy Charge ($/kWh)	0.0331
Off Peak Energy Charge ($/kWh)	0.0206
Fuel Cost Adj - Demand ($/kW-mo)	0.65
Fuel Cost Adj - Off Peak ($/kWh)	0.00055
Fuel Cost Adj - On Peak($/kWh)	0.00134
Sales Tax Rate	0.056
Power Factor Multiplier < 0.85	0.65
Power Factor Multiplier > 0.85	0.50

The assumed customer billing data (prior to the investment of storage) is shown in Table 5-3. Actual customer data was used as inputs to the calculation, however these were scaled upward in power and energy to better fit the technologies under consideration. These include energy consumption and demand by period and the measured reactive power at the peak hour.

Table 5-3
Billing Data

Days in Billing Cycle	28
Peak (operating) Days in Billing Cycle	20
On Peak Consumption (kWh)	2,562,450
Off Peak Consumption (kWh)	4,356,880
Actual On-Peak Demand (kW)	12,160
Actual Off-Peak Demand (kW)	11,790
Actual Reactive Demand (kVar)	10,420
Baseline Customer Demand (kW)	15,340

The reduction in peak load depends upon the load factor, i.e., load profiles with sharp peaks can use fixed, stored energy quantities more effectively in reducing peak loads. Load factor is calculated from the peak monthly demand and the monthly energy consumption and therefore represents an average value. The peak load reduction (kW) is estimated from the storage system power and energy ratings and the load factor, and this is subtracted from the annual and monthly peak loads.

In general, the power output during the peak load is less than the PCS power rating since the stored energy is discharged over more than one hour. Consequently, the PCS can be used to provide reactive power support to improve power factor at the meter. The maximum reserve reactive power capability is calculated such that the combined real and reactive components do not exceed the kVA rating of the PCS, and a new power factor is determined. In the case of the sample customer, for example, the power factor at peak without storage was 0.759 lagging, exceeding the 0.85 limit, and the customer is charged according to the tariff rules by assessing a higher billed demand. With a 1 MW / 4 MWh storage system, 787 kW is used to support the peak load, and 617 kVA remains to improve power factor[3].

New energy consumption is calculated based upon the assumed operating days of the storage system, resulting in a decrease of on-peak energy consumption (due to discharging) and an increase in off-peak consumption (due to charging). Charging energy accounts for the turnaround efficiency of the storage system.

A new monthly bill is calculated, and results for the three technologies are shown in Table 5-4. The main benefit is due to the reduction in monthly demand charge, followed by the reduction in annual demand charge. Energy benefits are nearly offset by energy charges, but there is a net positive benefit. The storage system does not change the fixed charges.

It is interesting to note that the bill savings for each of the technologies are virtually identical. This is because the only relevant differential parameter between the technologies that is an input to this calculation is roundtrip efficiency, and these were all very close across the technologies. Bill savings do not reflect capital costs or O&M costs.

A proforma analysis is performed based upon cash flows for each year. The net present value (NPV) of these cash flows is shown in Table 5-5. This table shows the utility bill savings, depreciation, O&M costs (excluding charging costs), changes in tax liabilities, and capital costs.

[3] Actually, in the example calculation, the storage system reduces the real component of peak load, and the power factor degrades. Available reactive power from the PCS is used to compensate for this, but overall the power factor is changed from 0.759 to 0.757 resulting in a slight penalty. However, the benefits of real power reduction significantly outweigh the penalties, and the net bill impact is beneficial to the customer.

Table 5-4
Utility Bill Savings by Technology

Monthly Utility Bill Savings ($)	NAS	VRB	CAES
Customer Demand Charge	598.36	598.36	598.36
On-peak Demand Charge	6851.42	6851.42	6851.42
Facilities Charge	0.00	0.00	0.00
Ton-taxable Customer Charge	0.00	0.00	0.00
On-peak Energy Charge	2648.00	2648.00	2648.00
Off-Peak Energy Charge	(2174.14)	(2354.29)	(2197.33)
Fuel Cost Adj - Demand	532.71	532.71	532.71
Fuel Cost Adj - Off Peak	(58.05)	(62.86)	(58.67)
Fuel Cost Adj - On Peak	107.20	107.20	107.20
Sales Tax	476.31	465.95	474.97
Total Bill Savings ($/mo)	8981.81	8786.50	8956.66

To calculate depreciation, published MACRS depreciation rates are applied each year to balance of the asset value. Federal and state marginal tax rates are combined into a single marginal tax rate as follows:

$$EffectiveTaxRate = StateTaxRate + (1 - StateTaxRate)xFedTaxRate$$

In the example, the customer is assumed to have a state marginal tax rate of 7% and a federal marginal tax rate of 40%. These are combined using the above equation to give an effective tax rate of 44.2%.

Finally, the NPV of the after-tax cash flow and the IRR is calculated. Based upon the capital and O&M cost assumptions, the calculated bill savings, and the tax impacts, none of the technologies show a positive net present value except for CAES. These are reflected in the IRR values that, except for the 12.68% return offered by CAES, are all below the assumed 7% cost of capital for commercial loans.

Table 5-5
Proforma Results (NPV)

	NAS	VRB	CAES
Revenues			
Utility Bill Savings	1,380,924	1,350,896	1,377,058
BESS Operating Costs			
Depreciation	(553,861)	(598,474)	(255,712)
O&M	(115,310)	(25,624)	(298,781)
Net Profit/(Loss) Before Tax	711,753	726,797	822,565
LESS: Tax	(314,595)	(321,244)	(363,574)
Net Profit/(Loss) After Tax	397,158	405,553	458,991
Net Profit/(Loss) After Tax	397,158	405,553	458,991
Capital Cost	(1,018,000)	(1,100,000)	(470,000)
ADDBACK: Depreciation	553,861	598,474	255,712
Net Present Value after Tax	(66,981)	(95,973)	244,703
Internal Rate of Return after Tax	6.19%	5.91%	12.68%

6
PEAK SHAVING – UTILITY OWNERSHIP

Application Requirements

If the utility owns the storage system, the evaluation is performed using utility economics calculations. Investment decisions are made on the basis of the cost (or revenue requirements) relative to alternative investments providing equivalent service.

A storage system sited on the secondary side of a substation could discharge power to support peak loads. If peak loads would otherwise exceed substation capacity, storage would reduce the loading through the transformer bank and, if sized properly, could ensure that capacity ratings were within limits. The transformer bank would be kept within the thermal limits of the oil and windings.

Storage can therefore be considered a tool to be used by utility transmission and distribution planners to manage peak load growth. To effectively site a storage system, the planners would use their load forecasts and hourly load profiles taken from the substation recorders to determine the power and energy ratings that must be provided by the storage system to meet peak demand.

However, unlike the customer peak shaving application, loads will continue to grow after the storage system is installed. Depending upon the rate of peak load growth, the remaining capacity of the substation, and the ratings of the storage system, new capacity must be added at some point in the future, e.g., a year or two. New capacity could be met by adding more storage, but this would increase off-peak loads (for charging), and ultimately the planner would have to add new capacity, either by constructing a new substation or by adding new capacity at the existing substation (switchgear, transformers, and feeders, for example).

With new capacity on-line, the storage system is no longer beneficial to the utility at the site (other than by providing secondary energy benefits to limit energy imports). The system would have many years of service life remaining, and the storage system could be moved to a different location within the utility or provided to another utility facing peak loading problems. Storage systems considered for this analysis are assumed to be transportable to provide T&D deferral benefits each year over the life of the system.

As a practical matter, transportable energy storage systems may be more feasible for smaller distribution systems since the number of substation capital projects per customer is higher. In large utilities, storage system assets could be shifted to different sites each year, possibly twice each year in utilities where both winter and summer peaking substations are found. The case study used in this analysis assumes a 10 MW / 80 MWh storage system.

As with the customer peak shaving application, the storage control system would have to include a means of measuring real-time loads and setting a suitable output threshold. It could be sited in the substation or anywhere within the network it serves, provided the lines are rated with sufficient capability to handle the power. Consequently, footprint is less of a concern for this application as compared to the customer application.

On the other hand, reliability is critical since the consequence of system failure is that loading normally supported by the storage system would have to be carried by the substation, exceeding its limits. While transformers are capable of handling short term loads in excess of normal ratings, this knowledge would have been incorporated into the planning process, and the storage investment would only have been made if short term ratings were insufficient. Consequently, the failure of the system would result in lost customer loads in order to avoid equipment degradation or catastrophic failure at the substation. Therefore, for storage to be used as an alternative to conventional T&D planning, the technology must have reliability comparable to the utility-grade equipment it is designed to replace, such as transformer banks.

Response times must be on the order of minutes up to about 30 minutes. There are no metering intervals to meet, and aggregated substation loads do not change rapidly. Furthermore, the dispatch setpoint would be at a maximum equal to the long-term rating of the transformer. In the worst case, the short-term rating would provide sufficient margin to handle the startup time of the storage system. All of the storage technologies addressed are capable of responding within the required time frame for this application.

As with the customer peak shaving application, roundtrip efficiency is not critical, and minimum efficiencies should be in the 60-70% range. There would be a similar energy consumption cost and energy avoidance benefit, but these would be based upon wholesale energy costs to the utility. The ratio of on-peak to off-peak wholesale energy prices, on average, are similar to the retail values since most tariffs are designed to pass through these costs to the customer.

Storage Technology Comparisons

NAS battery input data was based upon the assumptions used in the customer application. Costs were taken from an estimate very close in energy ratings used in the analysis (72 MWh versus 80 MWh), so scaling should be very close, and the power ratings were identical (10 MW). Again, variable costs assumed to be zero since the cost of charging is calculated separately.

While the PSB design does not lend itself for transportability, the system is included for comparison purposes. Capital costs taken from reported figures assume the 30th plant at a production rate of 10 plants per year. Costs are calculated using the “incremental” costs provided since the case study is rated for 10 MW / 80 MWh, within the 30% error band of the baseline 10 MW / 100 MWh plant. Using the incremental calculation, the total plant would cost $7.6M of which $1.5M would be power related ($150/kW) and $6.1M would be energy related ($76.25/kWh). This compares with the baseline energy cost of $65/kWh. Fixed O&M costs are taken for the 30th plant at $1/kW-yr and variable costs (excluding charging) are assumed to be zero. The efficiency of 65% was taken at the high end of the projected range.

Since the costs reported for the VRB represented a significantly smaller plant size, they were scaled as follows. Baseline stack costs were taken for the “Nth of a kind” (NOAK) plant as $300/kW, and the PCS costs were scaled using a relationship developed by Bechtel (Stolte, 1985) from a baseline $200/kW down to $126/kW for a total power related cost of $426/kW. Energy costs did not scale since the plant would be rated at the baseline of 8 hours, so energy costs correspond to $100/kWh. Fixed O&M costs are $2/kW-year and variable costs (excluding charging) are zero. Efficiency is taken as 70%.

The CAES technology is assumed to be of the above ground piping type since, clearly, for transportability the design could not rely upon the availability of suitable geologic formations at each site. Reported costs were for a discharge duration of 3 hours, but these were scaled linearly for the 8 hour system. Fixed O&M costs were taken at the upper bound of $7/kW-yr. Variable O&M cost is calculated as above using the same heat rate, however wholesale gas prices of $3.17 per thousand cubic feet was used, the US average price to utility customers in 2000. This corresponds to a variable cost of $0.012/kWh. Efficiency was assumed to be 75%.

Study assumptions used for all technologies in the analysis are shown in Table 6-1.

Table 6-1
Case Study Assumptions for Utility Peak Shaving

		NAS	PSB	VRB	CAES
Power Rating	MW	10	10	10	10
Energy Rating	MWh	80	80	80	80
Capital Cost - Power Related	$/kW	250	150	426	350
Capital Cost - Energy Related	$/kWh	192	76.25	100	30
O&M - Fixed	$/kW-yr	9	1	2	7
O&M - Variable	$/kWh	0	0	0	0.012
Efficiency		0.758	0.65	0.7	0.75

Modeling and Analysis

The methodology assumes that the transportable storage system is capable of deferring one capital project per year. At the end of the year, the project proceeds as originally planned. In effect, the storage system shifts the stream of annual capital investments by one year, and the present value of this investment stream is less than the original stream. These investments may occur within a single utility or multiple utilities depending upon the size and load growth rate. For simplicity, the rating of each capital project is assumed to be the same, and the case study assumptions are given in Table 6-2.

Note that the methodology does not make any assumptions about the capacity of the original substation or the load growth rate. If, for example, the original substation was rated at 50 MVA and load growth was 3% per year, then a storage system of only 1.5 MW would be required to avoid the deferral for one year. A 10 MW storage system (used in the case study) would provide deferral for this substation for about 9 years. In this case, the benefits calculated would assume that the system remained at the same location for 9 years before it was moved to another location. The 10 MW assumption is to some extent arbitrary and is selected as a meaningful size that the utility would use and is sufficiently large to include the larger technologies in this comparison.

Table 6-2
Assumptions for Utility Peak Shaving

Substation Capital Cost	$/kVA	400
New Substation Capacity	MVA	100
Substation O&M cost	$/sub/yr	50,000
Power - Peak	$/MWh	60
Power - Off Peak	$/MWh	20
Peak days	days/yr	100

The discount rate is calculated as the utility's weighted cost of capital from debt, preferred stock, and common stock. Table 6-3 shows the assumptions used which represent a typical utility cost structure. From these, the discount rate is calculated as 9.7% per year, and this is used to calculate the present value of the stream of capital investments over the life of the system. In the storage alternative, a similar present value calculation is made, however the investment stream does not include a first year investment but does include investments each year until one year beyond the storage system life. In other words, the total number of substation investments is the same in both alternatives, but the schedule is shifted one year.

Table 6-3
Cost of Capital Assumptions

Debt Cost	%/yr	8
Debt Capitalization Ratio	%	50
Preferred Stock Cost	%/yr	10
Preferred Stock Cap Ratio	%	15
Common Stock Cost	%/yr	12
Common Stock Cap Ratio	%	35

Since construction of the first substation is one year later than would otherwise be scheduled, the cost to maintain the substation in the first year is a cost savings attributed to the energy storage system. Substation maintenance costs are assumed to be $50,000 per year, so this is carried as a one-time benefit of storage.

Capital costs for the storage system are calculated using the assumptions described above. Charging and discharging energy costs are calculated based upon the number of operating days per year using the average on-peak and off-peak wholesale pricing and taking into account turnaround efficiency. Storage O&M costs are calculated based upon the system rating and the annual energy discharged over the year.

Results are presented in Table 6-4. All technologies provide the same substation capital benefit, first year substation O&M savings, and on-peak energy avoidance benefits., but they differ in the storage capital costs, charging costs, and storage O&M costs. For all technologies, the NPV is positive and the benefit/cost ratio is greater than one. Of particular interest are the CAES and PSB technologies with benefit/cost ratios of 4.2 and 3.9, respectively. CAES has a much lower capital cost than the other technologies, overcoming its higher operating costs from gas purchases. The PSB has both low capital costs and low O&M costs.

Table 6-4
NPV and Cost/Benefit Ratio

	NAS	PSB	VRB	CAES
Capital - Substation	34,275,721	34,275,721	34,275,721	34,275,721
O&M - Substation First Year	50,000	50,000	50,000	50,000
Capital - Storage System	(17,860,000)	(7,600,000)	(12,260,000)	(5,900,000)
Storage Charging	(1,834,478)	(2,139,284)	(1,986,478)	(1,854,046)
Storage Discharging	4,171,604	4,171,604	4,171,604	4,171,604
Storage O&M	(782,176)	(86,908)	(173,817)	(1,442,680)
NPV	18,020,671	28,671,132	24,077,030	29,300,599
Benefit/Cost Ratio	1.9	3.9	2.7	4.2

7 POWER CARRYOVER

Application Requirements

Advanced energy storage technologies such as flywheels and electrochemical capacitors may provide an alternative to conventional lead-acid UPS systems for backup power at sites where enhanced reliability is needed. Flywheels have been introduced commercially into this market, a trend that is increasing due to the need for increased power density at data centers and the need to support infrastructure space requirements. These technologies may also improve reliability since the battery component of the UPS is often considered problematic, and the flywheel alternative is increasingly used by customers.

The other storage technologies, such as VRB or NAS could be used in a dual mode to provide both power carryover and peak shaving. However, the present analysis does not consider this application.

In addition to providing an alternative storage technology, this application involves the use of an alternative power train topology. Conventional UPS systems are designed as “in-line” systems, in which the critical load is supplied entirely by the UPS. Power enters the UPS from the utility, it is rectified to the DC bus, and then is inverted and delivered to the load. In-line system therefore incur ongoing losses through the power electronics.

In contrast, “off-line” topologies allow utility power to feed the load directly, without converting the power mid-stream. In the event of a power disturbance, whether a momentary outage or voltage sag, the system detects the problem, transfers the source from the utility to the storage device, and continues to serve the load. When the disturbance passes, the system resynchronizes with the utility and transfers back to the utility source.

The alternative approach is to use the energy storage device to provide bridging time until a backup diesel generator set may be brought online to support the load for extended outages. These generators are normally kept warm and ready for service, and the time to start the engine, synchronize with the load, transfer (with mechanical switches) and ramp to the desired power is typically about 15 seconds. As for the storage technology, whether providing support for momentary outages or bridging time for diesel backup power, the storage discharge duration is about 15 to 30 seconds.

In many cases, it is necessary to ensure that the critical loads do not receive any loss of power during the transition between sources. For this reason, mechanically operating transfer switches do not suffice. Instead, high-speed transfer switches, with sub-cycle transition times are used. The detection, transfer, and response of the storage device must occur within a few milliseconds.

The storage technology must be highly reliable since systems designed for power carryover would only be used by critical loads. Systems must be, at a minimum, at least as reliable as lead-acid batteries. Commercial suppliers of these technologies promote them as more reliable than conventional systems.

The storage devices are cycled very infrequently (e.g., once per month), so roundtrip efficiency is not critical. For example, the energy required to recharge a 1 MW UPS after a 10 second outage would be only 2.8 kWh, a negligible cost to the customer. On the other hand, standby losses are important since they must be continually replenished, sometimes at significant cost.

Storage Technology Comparisons

The two storage technologies considered for this application are flywheels and electrochemical capacitors. These are the two "short term" technologies with discharge durations matching the application requirement of 15 to 30 seconds.

For the flywheel, the low speed technology is used because of their lower cost. Costs are based upon the reported $409/kW (combined energy and power) for a low speed flywheel in the grid stability application, plus an additional $50/kW for a high-speed static switch, for a total of $459/kW. Standby losses are assumed to be 2% to account for bearing friction, windage losses and auxiliary loads such as vacuum containment. The footprint is assumed to be 50 kW/ft^2 based upon the commercial 500 kW Active Power Clean Source 2 product data sheet. Fixed O&M costs are $45/kW-yr as reported.

Type III electrochemical capacitors are used as in the "Standby UPS for Substation" application since the bridging time for both the substation and customer applications are the same. Footprint is assumed to be 50 kW/m^2. Capital costs reported include the necessary hardware for switching between alternate sources, so the power-related costs of $300/kW are used, and the total installed cost of $708/kW is assumed. O&M costs are problematic since fixed O&M costs were not reported, and the figure included maintenance, real estate (which is included in the methodology), and energy costs. The maintenance component could not be determined from the maintenance costs provided, so fixed O&M is assumed to be the same as the VRLA battery of $10/kW-yr. Standby losses are 2%.

The technology related assumptions used as inputs to the model are shown in Table7-1. The case study is for a 1 MW system.

Table 7-1
Technology Assumptions

	Flywheel	Capacitor
System rating (kW)	1000	1000
Capital Cost ($/kW)	459	708
O&M - Fixed ($/kW-yr)	45	10
Standby losses	0.02	0.02
System footprint (kW/ft2)	50	50

Modeling and Analysis

Study assumptions common to both the flywheel and capacitor technology cases are shown in Table 7-2. These include an energy cost of $0.05/kWh that is intended to be the average (combined on-peak and off-peak) energy cost to the customer, exclusive of demand charges and fixed charges. HVAC performance, building costs, load factor, and financial data are typical values. The UPS data represents an inline system with a VRLA battery. Throughput efficiency for a Liebert Series 600 UPS is 92-93% at full load, and for average load this is assumed to be 88%. Footprint is calculated from the Series 600 product datasheet.

Table 7-2
Study Assumptions

Customer Data	
Average Energy Charge ($/kWh)	0.05
HVAC Coefficient of Performance	3
Building cost ($/ft2-yr)	10
Load factor	0.7
Financial	
Discount Rate	0.070
Study period (yr)	20
UPS Data	
UPS capital cost ($/kW)	450
UPS footprint (kW/ft2)	16.6
UPS fixed O&M ($/kW-yr)	10
Throughput efficiency	0.88

Capital costs are calculated for the UPS and the storage technology using the $/kW cost. All O&M costs are assumed to be fixed for both the UPS and the technology. Annual O&M costs are calculated, and the present value of future maintenance costs are calculated using the discount rate of 7%.

The annual energy lost for the UPS due to rectification and inversion is calculated based upon the maximum (1 MW) load, the load factor, and the throughput efficiency. The annual cost of this energy is determined from the average energy cost, and the present value of the recurring costs is calculated. In the case of the off-line storage technology, there are no throughput losses, but the standby power is calculated as a constant load over the year. The cost of energy and the present value of the recurring cost is calculated.

The losses described above represent increases result in dissipated heat with must be removed from the building through its HVAC system. Therefore, in addition to the cost of electricity to supplement the losses described above, there is a second cost of electricity to remove the heat. Based upon the assumed coefficient of performance (COP) of 3.0, the annual energy consumption is determined, and the HVAC energy costs are calculated.

The building area taken by the system represents a real cost to the customer. The cost may be lost opportunity to generate additional revenue in the space, for example, by adding production capacity to increase product revenues. The cost may also be due to increased lease costs for the building occupant. In either case, the annual building usage cost and present value is calculated for the UPS and the storage technology using a value of $10 per square foot per year.

The results are summarized in Table 7-3 in which the present values benefit (or cost) relative to the UPS system is given. In both the flywheel and capacitor cases, the capital costs exceed that of the UPS, so these are shown as negative. Capacitor O&M is the same as the UPS, so there are not cost advantages for O&M. Both the flywheel and capacitor were assumed to have the same standby losses and footprint, so the benefits from reduced losses and building footprint are the same. The dominant effect is seen to be the result of lower losses as compared to the UPS. In both technology cases, the system has a positive NPV.

Table 7-3
NPV Results

	Flywheel	Capacitor
Capital Cost	(9,000)	(258,000)
O&M	(370,790)	0
Energy consumption - losses	350,123	350,123
Energy consumption - HVAC	1,050,368	1,050,368
Building footprint	4,263	4,263
NPV	1,024,963	1,146,753

8
HYBRID OFF-GRID SYSTEMS/MICROGRIDS

Application Requirements

In this application, storage supplements a separate prime mover (fuel cell or diesel) to provide fast reacting load following and stabilization benefits and enhanced efficiency (full load versus part load). There are savings both in operating costs as well as capital investment due to size optimization (reduced rating of the DG unit), and reactive power support.

The storage system must have high efficiency since it represents a net load to the system. Since the energy to charge the storage comes from the diesel generator, and the total diesel generation on an annual basis is greater than the customer load due to turnaround efficiency.

The storage system must have the controls and PCS capability to provide dynamic response to voltage changes on the system, i.e., to source reactive power as necessary.

Speed of response must be less than a second, however this would occur when the storage system is already in operation. Response times from a cold start could be longer, on the order of a few minutes, since the diesel would carry the load during the transition period.

In the case study a small utility microgrid with a peak load of 20 MW is assumed. Without storage, this load is served by four diesel generator sets, each rated at 5 MW. The storage alternative is comprised of a 5 MW/40 MWh storage system with three gensets (8 hours of storage is an arbitrary specification that would provide intermediate load and peaking support). Storage is dispatched on a daily basis to maximize the benefits. However, this leads to a low life, and the salvage value of the storage components becomes an important factor. For example, if the energy component reaches end of life, the PCS may still have many years of life remaining.

Storage Technology Comparisons

For the VRB, power related costs scale as in the customer peak shaving application. Since the discharge duration is assumed to be 8 hours, the baseline energy-related costs apply. The VRB life would be dictated by the cycle life of the stack, and this is estimated to be about 6 years. Salvage value therefore assumes no stack value, and the PCS has a salvage value of 80% due to the remaining life. Since the electrolyte can be reused after the end of life, the BOS is assumed to have a 90% salvage value, and the total salvage value is estimated to be $116/kW (30%) and $90/kWh (90%) for the power and energy components, respectively.

Salvage value for the PSB would be similar to the VRB, and so the same salvage percentages of 30% and 90% are used for power and energy.

In the case of the NAS battery, the PCS is assumed to be the only salvageable component. The PCS has 80% of its value remaining, and is assumed to be about 80% of the power related costs.

As in the peak shaving examples, CAES is assumed to use above ground piping. Variable O&M costs are taken from the utility peak shaving application. The CAES would have a 30 year life, and this case could be calculated independently. However, for purposes of comparison, the CAES technology is also given a 6 year life but with a salvage value reflecting the high remaining life, i.e., (1-6/30)=0.8.

Other assumptions were made similar to the utility peak shaving application, and the inputs to the model are shown for the technologies in Table 8-1.

Table 8-1
Microgrid Technology Assumptions

	NAS	PSB	VRB	CAES
Rating (MW)	5	5	5	5
Rating (MWh)	40	40	40	40
Capital Cost - Power related ($/kW)	250	150	426	350
Capital Cost - Energy related ($/kWh)	192	65	100	30
Salvage Value - Power related	0.64	0.3	0.3	0.8
Salvage Value - Energy related	0	0.9	0.9	0.8
O&M - Fixed ($/kW-yr)	9	1	2	7
O&M - Variable ($/kWh)	0	0	0	0.012
Turnaround efficiency	0.758	0.65	0.7	0.75
Life (yr)	6	6	6	6

Modeling and Analysis

Diesel cost and performance figures represent a 5 MW diesel generator set since these are paralleled (for reliability) in groups of 3 or 4 for the storage and non-storage alternatives. A heat rate of 7,800 Btu/kWh is typical for machines of this size, however the efficiency drops off at part load, assumed to be 90% on average. The capital cost is $380/kW and the non-fuel variable operating cost is $0.005/kWh which are also typical values for a 5 MW diesel generator. Diesel fuel costs are assumed to be $10/MMBtu.

Voltage support provided by the storage system is valued according to the cost of capacitor banks that would have to be installed to provide equivalent reactive power to the grid in the absence of the storage technology. Capital and maintenance costs for the capacitors are taken from the Metlakatla Light & Power BESS project, $23.33/kVAr and $0.80/kVAr-yr.

For the diesel microgrid alternative, capital costs for the generator and capacitor bank are determined using the information given above. Fuel costs are calculated based upon the peak load, the load factor (70%) the cost of fuel, and the penalty for part load operation. O&M costs for the generator and capacitor banks are calculated as recurring costs.

For the hybrid microgrid alternative, the load served by the storage system is calculated first based upon a 100% DOD cycle each day. This is done to maximize the potential benefits related to improved generator load factor. The annual diesel production is calculated by subtracting the storage-supplied energy from the customer load and adding the energy required to charge the storage system. The fuel costs are then determined using the heat rate at full load. O&M costs for the storage system and diesel costs are calculated, and all recurring costs are converted to present values.

Results are shown in Table 8-2. Note that the diesel plant capital costs are reduced equally by each of the storage technology alternatives. Diesel fuel cost savings are captured for all storage scenarios. This is due to the improved heat rate of the generators operating at full load, although this is offset by the fact that total energy generated is more with storage (to account for turnaround efficiency). Diesel plant O&M costs increase slightly with storage due to the increased generation.

Table 8-2
Microgrid NPV

	NAS	PSB	VRB	CAES	Diesel Only
Capital cost - Diesel Plant	5,700,000	5,700,000	5,700,000	5,700,000	7,600,000
Fuel Cost - Diesel Plant	45,902,859	47,056,847	46,478,326	45,976,942	49,135,663
O&M - Diesel Plant	2,942,491	3,016,465	2,979,380	2,947,240	2,834,750
Capital Cost - Voltage Support	0	0	0	0	116,650
O&M - Voltage Support	0	0	0	0	18,492
Capital Cost - Storage Plant	8,930,000	3,350,000	6,130,000	2,950,000	0
Salvage Value - Storage Plant	(3,698,304)	(11,857,686)	(19,596,387)	(10,909,996)	0
O&M - Storage Plant	208,030	23,114	46,229	6,965,200	0
NPV	59,985,076	47,288,739	41,737,548	53,629,386	59,705,555

Storage plant costs range from $2.9 M for CAES to $8.9 M for NAS. These are offset by salvage value considerations, most notably in the VRB that has both high capital cost and high salvage value, an effect driven by the expensive electrolyte. O&M costs for the storage plant vary widely. In particular the CAES O&M costs are highest due to the added operating costs for fuel consumption.

9
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Technical cost and performance data for each of the technologies were provided by EPRI as part of the draft handbook on storage. In addition, data was taken from the following sources:

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