EPRI-DOE Handbook of Energy Storage for Transmission & Distribution Applications

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1000 Independence Ave., S.W.
Washington, DC 20585

Project Manager
Imre P. Gyuk

EPRI Project Manager
S. Eckroad

EPRI • 3412 Hillview Avenue, Palo Alto, California 94304 • PO Box 10412, Palo Alto, California 94303 • USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com

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ORGANIZATION THAT PREPARED THIS DOCUMENT

Technology Insights

EPRI PEAC Corporation

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Requests for copies of this report should be directed to EPRI Orders and Conferences, 1355 Willow Way, Suite 278, Concord, CA 94520, (800) 313-3774, press 2 or internally x5379, (925) 609-9169, (925) 609-1310 (fax).

CITATIONS

This report was prepared by

Technology Insights
6540 Lusk Blvd., Suite C-102
San Diego, CA 92121-2767

Principal Investigators
L. D. Mears
H. L. Gotschall

EPRI PEAC Corporation
942 Corridor Park Blvd.
Knoxville, TN 37932

Principal Investigators
T. Key
H. Kamath

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PRODUCT DESCRIPTION

The use of stored energy to support and optimize the electric transmission and distribution (T&D) system has been limited in the United States, but recent developments in advanced energy storage technologies and other technical, economic, and social factors suggest a promising future for energy storage. This Handbook provides an objective information resource on the leading, near-term energy storage systems and their costs and benefits for a wide range of T&D applications including distributed generation and power quality.

Results & Findings

The Handbook makes the business case for energy storage on the national and corporate levels and also provides a guide for T&D utilities looking at particular energy storage systems for representative applications in grid stabilization, grid operation support, distribution power quality, and load shifting. The Handbook provides a structured, easy-to-use resource for formulating comparative technology/application assessments and quantifying costs and benefits. It provides a comprehensive guide to the currently available energy storage technologies: lead-acid, nickel electrode, and sodium-sulfur modular batteries; zinc-bromine, vanadium redox, and polysulfide-bromide flow batteries; superconducting magnetic energy storage (SMES); flywheels; electrochemical capacitors; and compressed air energy storage (CAES). It describes the current status of each technology, its capabilities and limitations, and its specific costs and benefits. Each technology is ranked as to suitability, and compared with other technologies, in one or more of 14 different utility T&D system applications.

Challenges & Objectives

With the many challenges facing utilities and others responsible for reliable electricity service, considering the broadest range of technically and economically viable solutions is more important than ever. Electricity storage is a well known, yet often overlooked solution to many of the common problems of the T&D system. Only about 2.5% of the total electric power delivered in the United States is currently cycled through a storage facility while 10% of the delivered power in Europe and 15% in Japan is cycled through such storage facilities. While storage is not yet the universal solution for the ills of the electric delivery system, as more experience is gained and as technologies improve, storage may one day be ubiquitous in our power systems because of its attractive features, such as prompt start-up, modularity, easy siting, limited environmental impacts, and flexibility.

Applications, Values & Use

The Handbook provides a technology database and economic evaluation framework to T&D utilities for selecting and evaluating candidate energy storage options and formulating comparative assessments. Technology status, functionality, and cost information in the

Handbook will help users evaluate the readiness and viability of the technology for specific applications. Representative application cost-benefit examples given will establish a basis for more detailed, site-specific assessments by helping the utilities work with storage system suppliers to optimize their systems.

EPRI Perspective

EPRI undertook the development of this Energy Storage Handbook in partnership with the Department of Energy's Energy Storage Program whose participation in the preparation of Chapter 2 of the Handbook, National Perspective on Electricity Storage Benefits, was particularly valuable. The Handbook represents the first and only nationally available and broad consensus based information resource of significant depth and detail on energy storage for utility T&D applications. As such, it should stimulate the consideration and deployment of electricity storage in utility operations leading to increased T&D asset utilization, system reliability, and customer power quality.

Approach

The project team consisted of a broad panel of experts in electricity storage technology. The team summarized grid interactive storage experience in the United States, including the size of national storage markets. Throughout, the results of the research were augmented and reviewed by technology vendors and professionals from both academia and the utility industry. The team assessed both the readily monetized benefits of energy storage and its more qualitative benefits such as reliability and security. They developed a framework for assessing the costs and benefits of particular, consistently defined applications that simplifies analysis by applying a uniform treatment of major cost components such as electronic power conversions systems that are largely independent of energy storage technology. They gathered and summarized detailed information on the available energy storage technologies, the status of their development and deployment, bases and sizing for relevant applications, technology-specific costs, resultant benefits assessments, and pertinent references. The team then assembled the resource materials in a readable format that is consistent across all technology sections.

Keywords

Energy storage
Load leveling
Power quality
Batteries
Flywheels
Electrochemical capacitors
Compressed air energy storage (CAES)
Distributed generation

ABSTRACT

In the United States, the use of stored energy for the real time and short notice (milliseconds to a few minutes) support and optimization of the transmission and distribution (T&D) system has been limited to date, primarily due to a lack of cost-effective options as well as actual field experience and comparative evaluations. Recent developments in advanced energy storage technology, including a number of demonstration and commercial projects, are providing new opportunities to use energy storage in grid stabilization, grid operation support, distribution power quality, and load shifting applications. This Handbook assesses the potential benefits and costs of energy storage on the national and corporate level and provides a “technology-neutral,” comparative framework that utilities can use to formulate detailed application and site-specific assessments of specific technologies. The Handbook details the current status, capabilities and limitations, and costs and benefits of the leading available storage technologies: lead-acid, nickel-electrode, and sodium-sulfur modular batteries; zinc-bromine, vanadium redox, and polysulfide-bromide flow batteries; superconducting magnetic energy storage (SMES); flywheels; electrochemical capacitors; and compressed air energy storage (CAES). Each technology is ranked as to suitability, and compared with other technologies, in one or more of 14 different utility T&D system applications.

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In 2002, A Handbook on Energy Storage for T&D Applications was proposed to our members as an EPRI project and duly funded. EPRI gratefully acknowledges the funding and the moral support lent by the funders of Program 94, in general, and the members of the Program 94 Task Force, in particular, chaired by John Del Monaco, PSE&G.

An initial draft of the Handbook, published as an interim report December 2002 (1007189), was composed of stand-alone chapters, each prepared by one or more contractors, for an initial set of seven energy storage technologies. During 2003, EPRI expanded the Handbook content with three more energy storage technologies. While the applications and the approach for the benefit – cost assessments have since been standardized for the 2003 edition, the respective technology descriptions and deployment status information have been drawn from the initial work, with updates from various resources as appropriate. Individual chapter authorship is acknowledged below.

After the initial draft was published in 2002, it was determined that a standardized approach was needed for defining T&D applications and for developing a methodology for assessing the associated benefits and costs to all the technologies. EPRI gratefully acknowledges the "above-and-beyond-the-call-of-duty" devotion to this task that was manifested by Harold Gotschall and Dan Mears, Technology Insights.

In addition, EPRI would like to gratefully acknowledge the cooperation and sponsorship of the U.S. Department of Energy through the Sandia National Laboratories in the production of the Handbook. Contributions sponsored by the DOE have broadened the scope of the Handbook to include a National perspective on the benefits of electricity energy storage.

Throughout the course of the expanded and standardized Handbook development, review and comment has been contributed from industry and academia experts for select topics. In addition, several energy storage vendors have contributed directly to update the information and support the benefit – cost assessments for their respective technologies. All of these contributions are gratefully acknowledged as set forth below.

Accordingly, the contracted principal investigator(s) and their respective companies plus the major contributors for the respective chapters of this Handbook are listed as follows:

- Chapter 1 – Introduction.
  Principal Investigators: Harold Gotschall and Dan Mears, Technology Insights
- Chapter 2 – National Perspective on the Benefits of Electricity Storage.
  Principal Investigators: Joe Iannucci and Jim Eyer, Distributed Utility Associates
  Contributors: John Boyes, Sandia National Laboratories; and Imre Gyuk, U.S. DOE
- Chapter 3 – T&D Applications for Benefit - Cost Assessments.
  Principal Investigators: Harold Gotschall and Dan Mears, Technology Insights
  Contributors: Bill Torre, SDG&E; Dale Bradshaw, TVA; Abdel-Aty Edris, EPRI; Mariesa Crow, University of Missouri at Rolla; Brendan Kirby, ORNL; Dave Bertagnolli, ISO-NE; Tom Key, EPRI PEAC
- Chapter 4 – Energy Storage Benefits and Benefit Quantification.
  Principal Investigators: Harold Gotschall and Dan Mears, Technology Insights
  Contributors: Brendan Kirby, ORNL; Dave Bertagnolli and Mike Potishnak, ISO-NE; Toby Edmonds, Innogy
- Chapter 5 - Common Financial Parameters and Cost Elements.
  Principal Investigators: Harold Gotschall and Dan Mears, Technology Insights
  Contributors: Tony Siebert and Tor Moen, ABB
- Chapter 6 – Lead Acid Batteries.
  Principal Investigator: Haresh Kamath, EPRI PEAC
  Contributors: Steve Eckroad, EPRI; Mike Swift, Swift Industrial Power; Sam Wilson, T.S. Williams & Associates; Steve Vechy, EnerSys, Inc.; Brad Roberts and Tim Wood, S & C Electric Company
- Chapter 7 – Nickel-Cadmium and Other Nickel Electrode Batteries.
  Principal Investigator: Haresh Kamath, EPRI PEAC
  Contributor: Jim MacDowall, Saft
- Chapter 8 - Sodium – Sulfur Batteries.
  Principal Investigator: Harold Gotschall and Dan Mears, Technology Insights
  Contributor: Ted Takayama, NGK Insulators, Ltd.
- Chapter 9 – Zinc Bromine Batteries.
  Principal Investigator: Haresh Kamath, EPRI PEAC
  Contributors: Greg Nelson and Peter Lex, ZBB Energy Corporation; Nancy Clark, Sandia National Laboratories; Rick Winter, Consultant
- Chapter 10 - Vanadium Redox Batteries.
  Principal Investigator: Ben Norris, Gridwise Engineering Company
  Contributors: Tim Hennessy, VRB Power Systems; Katsuji Emura, Sumitomo Electric Industries and Malcolm Jacques, Reliable Power
- Chapter 11 - Sodium Polysulfide – Sodium Bromide Batteries.
  Principal Investigators: Phil Symons, Electrochemical Engineering Consultants, Inc.; Susan Schoenung, Longitude 122 West; and William Hassenzahl, Advanced Energy Analysis
  Contributors: Mark Kuntz and Toby Edmonds, Innogy; Anthony Price, Consultant

- Chapter 12 - Superconducting Magnetic Energy Storage.
  Principal Investigators: William Hassenzahl, Advanced Energy Analysis; Susan Schoenung, Longitude 122 West; and Phil Symons, Electrochemical Engineering Consultants, Inc.
  Contributor: Tom Abel, American Superconductivity, Inc.
- Chapter 13 - Flywheel Energy Storage.
  Principal Investigators: Haresh Kamath and Tom Key, EPRI PEAC
  Contributors: Charles Bakis, Dept. of Engineering Science and Mechanics, Penn State University; Scott Richey and Bryan Plater, Active Power, Inc.; Matt Lazarewicz, Beacon Power Corporation; David Townley, Pentadyne Power Corporation
- Chapter 14 - Electrochemical Capacitors.
  Principal Investigators: John Miller, JME; and Tom Key, EPRI PEAC
  Contributors: Michio Okamura, ECaSS; Haresh Kamath, EPRI PEAC
- Chapter 15 - Compressed Air Energy Storage.
  Principal Investigator: Stuart Knoke, Energy International
  Contributors: Robert Schainker, EPRI; Sep van der Linden, Brulin Associates

Overall Handbook Integration and Assessments: Harold Gotschall and Dan Mears, Technology Insights; and Haresh Kamath, EPRI PEAC Corporation.

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1
INTRODUCTION

The use of stored energy is fundamental to the generation of electric power, whether in fuel stockpiles for fossil or nuclear power plants, or the seasonal runoff and dammed waterways for hydroelectric power plants. However, the use of stored energy for the real time and short notice (milliseconds to a few minutes) support and optimization of the transmission and distribution (T&D) system has been limited to date, due primarily to the lack of cost-effective options. At present, large (100s of MW_{ac} for up to 10 hours) pumped hydro facilities are the dominant means of electricity storage, primarily for daily load shifting, but also for regulation control and spinning reserve applications. In the U.S., several lead-acid battery facilities have been deployed during the 1980s and 1990s with capacities up to 40 MW_{ac} for applications requiring discharges of a few seconds up to a few hours. In addition, one compressed air energy storage (CAES) facility has been deployed in the U.S. with a capacity of 110 MW_{ac} for up to 10 hours, plus a 290 MW_{ac} CAES plant has been operating in Germany. Altogether, about 2.5% of the total electric power delivered in the U.S. is currently cycled through a storage facility, mostly pumped hydro. Interestingly, for Europe and Japan, about 10% and 15%, respectively, of the delivered power is cycled through such storage facilities, reflecting relatively more attractive pumped hydro sites, and particularly for Japan, higher electricity prices per se and much larger differences between peak and off-peak prices.

While the addition of pumped hydro facilities is very limited, due to the scarcity of further cost-effective and environmentally acceptable sites in the U.S. and other developed countries, several advanced energy storage technologies are being developed, demonstrated and recently commercialized with potential for T&D applications. Most are starting in the multi-to-10s of MW_{ac} of capacity ratings as "distributed resources" that derive part of their value based on locational conditions, as opposed to the large, central pumped hydro energy storage facilities. Accordingly, such distributed energy storage technologies must also compete with a range of distributed generation options. Alternatively, hybrid generation/storage systems may combine to provide the optimal solution for the T&D system than either alone.

A factor in the interest and growth in distributed resources has been the ongoing and still evolving restructuring of the electric utility industry. As a result, many formerly “vertically” integrated utilities have or are being restructured into unregulated generation and service companies, federally regulated transmission aggregate companies, and state regulated distribution companies. At present, every combination of the above exists in the U.S. with many areas still in a transitional process. During this uncertain restructuring period, most T and/or D utilities are operating on a performance based regulatory structure whereby the least investment cost solution is generally preferred, and hence a factor in an increased interest in smaller and less capital intensive distributed resources, including energy storage. However, there are institutional issues related to restructuring that must be resolved for T and/or D utilities to be able to access the full value of distributed resources in general and most energy storage options in particular. For example, a restructured T and/or D utility is typically not allowed to accrue the benefits from owning an energy storage facility related to load shifting, i.e. replacing high cost peak energy with low cost off-peak energy, or to sell ancillary services from such an energy storage facility. Either or both could make the difference in achieving attractive economics that are otherwise lacking if based only on deferring a more capital-intensive upgrade in the system.

Broad technical, economic and social factors also suggest a promising future for energy storage technologies. Among the more compelling economic forces is the growth in automated industrial processes and communications over the past decade, during which reliance on electronic transactions has become a permanent dimension of the U.S. economy. This trend has created demand for premium electric power, which can often be more cost effectively achieved through the deployment of distributed energy storage systems. By the end of the past decade, a generally strong economy and associated load growth had caused significant strain on the T&D system in many parts of the country, while public environmental awareness added to the social cost (and practical difficulty) of expanding transmission rights-of-way. As a result, optimization of the existing T&D infrastructure through alternative and creative congestion management and load relief programs has been elevated in priority. Concurrent advancements in power electronic technologies have played key roles in both the demand for premium power and the mitigation of power disturbances, as well as in enabling a new dimension in real-time T&D control and management. Technologies such as Flexible AC Transmission Systems (FACTS), initially developed through EPRI programs, are strategically positioned to enable the introduction of energy storage to enhance both power quality and T&D asset utilization, plus the economic use of wind and solar renewable resources.

With the reality of energy storage and power electronic technology advances plus application opportunities and challenges for the T&D utility sectors, EPRI has undertaken the development of this Energy Storage Handbook for T&D Applications. The synergism between the goals of this effort and those of the DOE Energy Storage Program has led to DOE's co-sponsorship, participation and particularly the preparation of Chapter 2 – National Perspective on Electricity Storage Benefits.

Purpose

The purpose of this Handbook is both broad and specific. As noted, DOE is collaborating in the effort with emphasis on addressing the National perspective on the benefits of grid-interactive energy storage, which draws from their extensive background of related work. More specifically, the Handbook provides an objective information resource on the leading, near-term energy storage systems and their respective benefit-cost assessments for leading, opportunity T&D applications. Hence, the Handbook communicates the business case for energy storage at the corporate and policy levels within industry and government, respectively, as well as guides T&D utilities for screening candidate energy storage systems for representative, opportunity applications.

As warranted by such screening results, the Handbook also provides the T&D utility user of this Handbook a structure for formulating more detailed application and site-specific assessments plus a basis for selecting which energy storage options to further evaluate for related deployment considerations. Such detailed assessments by the utility should have the benefit of direct interactions with the storage system suppliers that are typically able to further optimize their respective systems beyond the representative application assessments presented herein. As such, the utilities are well served with objective information for screening decisions and the storage system suppliers are well served by being identified with the potential for such applications.

Pending the realization of such benefits, the intent is to periodically update and expand the Handbook, including the addition and perhaps deletion of energy storage systems and applications.

Scope of Handbook

As noted, the scope of this Handbook is both broad and specific. The broad scope follows in Chapter 2 with the National perspective on the benefits of energy storage, which goes beyond the T&D sector to include other sectors, such as generators, end-use consumers, vendors, regulators and other government agencies. This material draws upon the work that DOE has been supporting through their Energy Storage Program, primarily administered through the Sandia National Laboratories. To begin, the value chain between all the stakeholders is addressed that establishes the broad bases for answering the question: “why electricity storage?”. Storage implementation issues are then reviewed, including the assessment of the non-storage alternatives and the related permitting and siting considerations. A summary of grid interactive storage experience in the U.S. is provided as the base of precedent and lessons learned. The size of National level storage markets and benefits are presented, including the readily monetized benefits and the more qualitative benefits such as reliability and security. Finally, market conditioning and the R&D needs and opportunities are addressed that serve to guide related programs funded by DOE and EPRI.

The remainder of the Handbook has been organized to reflect a user/vendor information exchange, i.e., utility-user application requirements and values are posed to energy storage system vendor/supplier entities that have responded with design, performance and cost information. Chapters 3, 4 and 5 describe the specific T&D applications, economic benefits and common cost elements for evaluation from the T and/or D utility perspective. Chapters 6 through 15 provide technical descriptions, summarize the state of development, and present the results of economic assessments of the T&D applications presented in Chapter 3 from a supplier point of view. This approach has been adopted as a means of enhancing insight to the cost and performance of emerging energy storage technologies by imposing uniform treatment of major cost components that are largely independent of energy storage technology, such as electronic power conversion systems.

In Chapter 3, the specific T&D based applications for which applicable energy storage systems are assessed in the subsequent “technology chapters” (Chapters 6 through 15). Applications are organized in four major categories: Grid Stabilization, Grid Operation Support, Distribution Power Quality, and Load Shifting. Each major category is then sub-divided into the specific applications shown in Table 1-1.

Table 1-1
T&D Energy Storage System Applications Assessed

Grid Stabilization (GS)			**Grid Operational Support (GOS)**		**Distribution Power Quality (PQ)**		**Load-Shifting (LS)**	
Angular Stability (GAS)	Voltage Stability (GVS)	Frequency Excursion Suppression (GFS)	Regulation Control (RC)	Conventional Spinning Reserve (SR)	Short Duration PQ (SPQ)	Long Duration PQ (LPQ)	3 hr (LS3)	10 hr (LS10)

These individual applications are described with emphasis on the grid phenomena being addressed and the role of stored energy to support the grid. Top-level requirements (e.g., duty cycles) and reference values used in benefit-cost assessments are identified. In addition to the nine single function applications shown in Table 1-1, five combined function applications (e.g., combined PQ and LS) are also characterized. Prior work has shown that the economics of most energy storage systems are significantly more attractive than single function applications, albeit with potential institutional issues as noted above. The energy storage systems suitable to address the resulting set of fourteen representative opportunity applications are identified. Chapter 3 also introduces the following energy storage systems presented in this initial edition of the Handbook: lead-acid, nickel-cadmium and sodium-sulfur modular batteries; zinc-bromine, vanadium redox and sodium polysulfide-sodium bromide flow batteries; superconducting magnetic energy storage; flywheels; ultracapacitors; and compressed air energy storage.

In Chapter 4, the bases and approach used in quantifying the benefits associated with each application are presented. Benefits are treated in two categories: those associated with representative electricity market rates (e.g., trading values for electricity energy, demand, ancillary services, etc.) and those related to the avoided cost of alternative solutions (e.g., upgrade deferral, competing technology, etc.). The quantification of market-based benefits is obtained from a representative single value, while the value of avoided costs is represented over a range (e.g., the net capitalized costs of alternative technology solutions are shown for a range of $500 to $1500/kW). This approach is used for all the energy storage systems addressed in this Handbook. It is intended to allow the reader to conduct an initial screening of options by extrapolating the results of economic analyses reported herein to project specific values and options. Intangible benefits associated with energy storage solutions to T&D applications are also characterized.

Similarly, Chapter 5 describes the bases and approach used in quantifying costs that are common to the various energy storage systems. These costs are generally those outside the scope of supply for the energy storage equipment supplier and if not will be treated on a case-by-case basis. The major common cost element is the power conversion system, the development of which is generally evolving in parallel with the development of energy storage systems and is subject to otherwise wide variability in cost estimates, depending on the supplier and assumptions regarding design maturity and volume of orders. Other common cost elements include the balance of plant, grid interface and routine property taxes and insurance.

Chapters 6 through 15 then follow for the respective energy storage systems with a description of the energy storage technology, status of development and deployment, bases and sizing for the relevant applications, technology-specific costs and the resultant benefits assessments, plus pertinent references.

2
NATIONAL PERSPECTIVE ON ELECTRICITY STORAGE BENEFITS

Why Electricity Storage?

Integrating Electricity Storage into the Electricity Value Chain

With the myriad of challenges facing utilities and others responsible for reliable electricity service, considering the broadest range of technically and economically viable solutions is more important than ever. Electricity storage is a well known, yet often overlooked solution to many of the common problems which frequently arise. [1][2][6][21][22]

The purpose of this chapter is to illuminate the many economically viable opportunities for storage inclusion in power systems by utilities and/or their customers, plus its related societal benefits. This chapter addresses the business case for electricity storage technologies that derive from its features, such as prompt start-up, modularity, easy siting, limited environmental impacts, and flexibility to be used for multiple applications. While storage is not yet the universal solution for the ills of the electric delivery system, as more experience is gained and as technologies improve, storage may one day be ubiquitous in our power systems.

For example, storage devices could be placed in the utility distribution system to supply peaking power to a feeder on rare occasions when the local load is beyond its operational limits. This simple storage use can defer the need for a costly distribution upgrade until all doubt has been removed that the load has indeed grown on the feeder.

A good use of storage for electricity end-users is to mitigate power quality or reliability problems which affect sensitive equipment. Here the storage device would be placed in series with the sensitive load, continuously filtering and then providing energy during momentary or extended outages, depending on the capacity and discharge duration of the storage device installed.

Finally, consider a renewable resource such as photovoltaics or wind generation connected to the grid but unable to obtain a capacity payment for its output, and hence losing some financial advantage. The use of a storage device could firm up that intermittent renewable capacity enough to earn some additional and substantial economic benefits on the open market.

These applications and their associated value propositions provide benefits to their owners. Depending on the type, design and size of storage device which is installed, these individual benefits may be sufficient to pay for a storage system.

What is unique and profoundly important about storage is its flexibility to produce multiple benefits from a single device. In theory one storage device could be employed simultaneously in all three of the above applications, vastly improving the economics of the storage installation. And this is not the limit of the value of storage: a single device could have more than three benefit streams, although each application must be compatible physically and in a business (e.g., contractual) sense.

This chapter will first review the business stakeholders for the use of storage. Thirteen individual benefits of storage are defined and quantified and ranked, using a recent study addressing the situation in California as the basis. The resulting ten year market potential and economic benefits are also estimated. Storage qualitative benefits, implementation experience, project decision techniques and regulatory approaches to storage are reviewed. A national perspective is then offered on US markets and benefits of the use of storage, remaining market conditioning needs and suggested storage R&D areas.

Potential Electricity Storage Beneficiaries and Other Stakeholders

Electric Utility

Storage is already a common part of many utility systems, but it is not yet integral to transmission and distribution operations. Storage is a commonplace complement to large generation plants, and at the other size extreme, batteries are the norm for small equipment protection, ride-though and emergency operation. But in between these two applications, roughly in the MWac size range, there are many uses for which storage has not yet been applied.

Energy storage could provide benefits to all elements of the electric utility system: supply (purchase and/or generation), transmission, and distribution. For utilities that provide non-traditional value-added utility services storage could also be an important part of offerings such as “premium” power or holistic energy solutions.

Storage can be a flexible element of a responsive, cost-competitive electric supply system. It can be used to store low-cost energy – whether generated or purchased – when demand is low, for use when energy demand and value is high.

Energy storage can be used in lieu of additional peaking power plants whose fuel efficiency, air emissions and asset utilization are all relatively poor.

Energy storage can reduce need to use generation for load following and as spinning reserve. That, in turn, reduces part load operation of generation yielding reduced wear and tear, better average fuel efficiency and possibly reduced air emissions.

Storage used within power distribution systems and/or at specific locations which are served by heavily loaded transmission lines reduces congestion on the transmission lines. Electricity storage can also interact electrically with transmission lines to increase lines' throughput and/or stability. Specifically, storage can be used to maintain voltage and perhaps more importantly, to maintain transmission frequency to prevent system collapse.

Geographically-targeted storage can increase the asset utilization of existing transmission and distribution (T&D) equipment.

Storage could be used to defer or eliminate the need for high cost investments in new or upgraded T&D facilities (wires, transformers, capacitors or capacitor banks, and substations). In addition, storage could also be a cost-effective option for utilities to improve power quality or service reliability for customers with high value processes or critical operations.

Individual Electricity End-Users

Electricity storage installed by or for specific end-users can provide significant benefits. Key uses include managing cost for electric service, reducing financial losses due to poor power quality, and reduced financial losses due to unacceptable electric service reliability.

To manage their electric energy cost, end-users store inexpensive energy when demand for and price of the energy is low. When demand for price of energy is high, and if applicable when demand charges apply, the stored energy is used instead of energy from the grid.

Many commercial and even residential end-users use device-specific uninterruptible power supplies (UPSs) to reduce effects associated with outages and poor power quality. In some cases facility-wide UPSs are used.

Electricity storage is financially viable primarily for commercial and industrial end-users whose overall energy cost is high and/or for which power-related down-time has high cost.

Utility Ratepayers

To the extent that electricity storage reduces the utility's total cost-of-service – relative to the utility's most likely solution, and to the extent that that cost-reduction is passed on to ratepayers, the ratepayers derive a benefit also.

Consider storage used by a utility to address a distribution problem which affects the power quality of two nearby utility customers. Though the storage provides benefits to two individual end-users, usually the cost is borne by the utility ratepayers as a group.

Energy Service Providers

One possible important stakeholder in the utility marketplace of the future could be non-utility entities which provide an array of energy services and equipment. Commonly referred to as energy services companies (ESCO) or energy services providers (ESP), these organizations could play an important role with regard to bringing energy storage to the electricity marketplace.

These entities could, for example, provide “plug-and-play” electricity storage systems for end-users or utilities. Or, ESPs’ offerings could include some or all of the following: storage system financing, engineering design and sub-system integration, procurement, systems aggregation, permitting, installation, interconnection, or maintenance.

ESPs could also include storage in broader, more holistic energy solutions for facilities, local power distribution areas, or even regional energy supply and delivery. Such holistic approaches could include, for example direct load control, on-site generation, system controls, fuels management, and dynamic energy cost management based on real-time energy prices and other decision criteria.

Equipment Vendors

Companies which manufacture and/or sell electricity storage systems, subsystems or related services have a large stake in the widespread use of storage systems for utility applications. Just some of the equipment types that would be affected include: interconnection and switchgear, control systems for storage systems and/or that integrate storage into a broader energy system, batteries and related chemicals, inverters and other power conditioning, turbines and generators for pumped hydroelectric, and combustion turbines, compressors, generators and other subsystems for CAES. Also at stake is a significant amount of system integration and support.

The Environment

Renewables and storage naturally complement one another. Already some form of storage is often used in non-grid connected renewable power systems. For grid connected systems storage is a natural way to maximize the benefits by time shifting or firming the output of non-dispatchable renewables generation.

Depending upon how it is used, electricity storage could reduce environmental impacts from electricity generation, transmission and distribution. Improvements are associated with improved generation fuel efficiency, reduced air emissions and possibly reduced need for central utility infrastructure, including generation and transmission facilities.

Regulators and Independent System Operators

As the electricity marketplace of the future emerges, electric utility regulators will face a widening array of challenges as they pursue regulation that balances considerations such as service cost, service reliability, fuel diversity, environmental effects, and infrastructure security. [6]

Though regulators have limited direct authority to require use of storage, if and when utilities exercise their prerogative to use storage, regulators will be required to understand the related implications.

There may be opportunities for Independent System Operators (ISOs) and/or Regional Transmission Operators (RTOs) to use storage or to provide incentives for utilities or energy end-users to install storage. For example, storage could serve as one option when ISOs need to balance regional loads or to stabilize the transmission system. With a network control system, smaller distributed storage systems located at or near end-user sites could be aggregated to provide power in blocks which are significant enough for the ISO. The ISO would have to be able to dispatch the aggregated storage power block like it would one large power plant. [6]

Electricity Storage Benefits

This section characterizes financial benefits associated with use of storage. A benefit may be a revenue stream or a cost that can be avoided if storage is used: an "avoided cost." This section also provides a brief overview of market potential for energy storage, if used for the benefits described.

Introduction

Several benefits from energy storage for utility applications are well known: reduced financial losses due to poor power quality and power outages, energy price arbitrage involving charging with low priced "off-peak" energy for use later when energy cost and price is high, and utility ancillary services.

Over the last ten to twenty years several other possible benefits from energy storage have been proposed, evaluated and in some cases demonstrated. For example, the class of benefits called "distributed" benefits (that accrue based on the location of storage capacity), and benefits associated with superior performance of the transmission system.

One of the most comprehensive, publicly available listings of benefits from electricity storage was developed for the California Energy Commission (CEC) and the U.S. Department of Energy (DOE) in support of an energy storage-related RFP. A listing of those benefits, along with other data associated with benefits, is shown in Table 2-1. Each benefit listed in Table 2-1 is described in the following chapter subsections. [18]

In the table, the first two columns after the listing indicate the amount of storage system discharge time (discharge duration) required for each benefit. The next column shows the lifecycle benefit per kW of storage suggested for the respective benefit. The final two columns contain: 1) estimated market potential in California, for storage used for each benefit and 2) the total economic benefit in California associated with the estimated market potential. The benefits are rank-ordered with the highest individual benefits at the top of the table. (An extrapolation of California values to national values is described later in this chapter.)

Table 2-1
Summary: Electricity Storage Benefits and Market Potential for California

Benefit	Discharge Duration* Minimum	Discharge Duration* Highest	Lifecycle Financial Benefits ($/kW)	Maximum 10-year Market Potential (MW)	Ten-year Economic Benefits ($Million)**
Distribution Upgrade Deferral Top 10th. Percentile of Benefits	2	6	1,067#	161	172
Time-of-Use Energy Cost Management	2	per tariff	1,004	4,005	4,021
Power Quality Reduced Financial Losses	10 seconds	1 Minute	717	4,005	2,872
Distribution Upgrade Deferral 50th. Percentile of Benefits	2	6	666#	804	536
Renewables Contractual Time-of-Production Payments	6	10	655##	500	328
Transmission Upgrade Deferral	4	6	650#	1,092	710
Demand Charge Management	6	11	465#	4,005	1,862
End-user Electric Service Reliability Reduced Financial Losses	0.25	5	359	4,005	1,438
Bulk Electricity Price Arbitrage	1	10	200 - 300	735	147 to 220
Central Generation Capacity (Avoided Cost or "Profit")	4	6	215#	3,200	688
Renewables Capacity Firming	6	10	172##	1,800	310
Transmission Support (Avoided Cost or "Profit")	2 Seconds	5 Seconds	82	1,000	82
Ancillary Services (Avoided Cost or "Profit")	1	5	72***	800	58
Avoided Transmission Access Charges	1	6	72***	3,200	230
Avoided Transmission Congestion Charges	2	6	72***	3,200	230

*Hours unless other units are specified.
**Over ten years, based on lifecycle benefits times maximum market potential (market *estimates* will be lower).
***Placeholder values. The actual benefit was not estimated.
#Does not include incidental energy-related benefit.
##Wind generation.

Source: California Energy Commission and the United States Department of Energy [18]

For this document market potential estimates are provided to convey a sense of the magnitude of potential. Values presented herein are market *potential* values, not market estimates or projections and are not meant to imply that market potential estimates indicate how much storage will be installed. Market potential estimates are made based on estimates raw *technical* potential, current knowledge, trends, and reasonable assumptions about cost and a wide variety of benefits.

Ten-year market potential estimates used are listed in Table 2-1. The rationale used to make those estimated is summarized in Table 2-4 later in this chapter.

When describing benefits in this chapter, a few standard assumptions are used since no specific storage technologies are considered. The storage plant life used is always 10 years. A general price escalation of 2.5% is assumed for all costs and prices and the discount rate used to calculate net present values (NPV) is 10%.

To simplify lifecycle net present value calculations in this chapter, a "net present value factor" (NPV factor) is calculated. That value is used to convert a single/first year benefit into a ten-year net present value. Given the standard assumption values of 2.5% standard cost/price escalation rate, 10% for discount rate, and ten years for storage life, the NPV factor is 7.17.

Consider an example: for an annual benefit of \$100/kW-year the lifecycle net present value benefit is \$100/kW-year * 7.17 = \$717/kW over ten years. (Note that this approach assumes that the annual benefit for all ten years of the storage plant's life is the same as that for the first year, except that all related costs and prices escalate at 2.5% per year.)

The financials used in this chapter, reflect nominal dollars; specifically, the 10% discount rate is the nominal rate including effects of inflation. Elsewhere in this document a real discount rate is used to estimate net present value, i.e., to remove effects of inflation from the calculus.

Utility Transmission and Distribution Financial Benefits

Entities which own transmission lines or that are responsible for the operation of the transmission system (e.g., Independent System Operators – ISOs, or Regional Transmission Organizations – RTOs) could use storage several ways.

Storage systems with high power output and with discharge duration of a few seconds could be used to stabilize power flows through the transmission system.

Storage which interacts directly with a transmission line can increase the amount of current which flows through the line (e.g. via damping).

Storage located downstream from transmission lines (for example, connected to power distribution systems) can be used to reduce loading on the transmission system during periods of peak demand. Effects may include: reduced energy losses as reduced current passes through the wire during periods of heavy loading, capacity not used can be used for another power flow, or a transmission system upgrade may be deferred.

Organizations which own and operate electricity distribution systems (DisCos) could use storage for several benefits.

Storage systems could be used to stabilize power flows through the distribution system. Storage could provide reactive power needed to optimize localized power flows. Storage which interacts directly with a distribution feeder can increase the amount of current which flows through the line (e.g. via damping).

Storage located downstream from overloaded distribution lines can be used to reduce loading on the circuit during periods of peak demand. Effects may include: reduced energy losses as current passes through the wire, wear and tear of distribution equipment (e.g. due to thermal stressing or frequent tap changer resetting) is reduced, thus increasing equipment life, or a distribution system upgrade may be deferred or avoided.

Deferred T&D Upgrade Investment

The single year transmission or distribution deferral benefit is the financial value associated with deferring a utility T&D upgrade for one year. It is the financial carrying charges that are avoided because the upgrade is not undertaken immediately.

Consider an upgrade to a 9 MWac distribution system. Typically 3 MWac will be added, a 33% increase, after the upgrade the distribution system can serve 12 MWac of load. Using an average annual carrying cost of $50 per kW in California for distribution capacity added, the annual (single year) carrying charges for the upgrade are $150,000. [28][29]

To defer an upgrade for one year it is assumed that the energy storage plant's power output must be equal to the expected load growth for the next year. Continuing with the example above: if load growth on the circuit is 2.5% per year, during the next year then load growth is expected to be 9 MWac * .025 = 225 kW. In theory, a storage plant rated at 225 kW could allow the utility to defer the distribution upgrade for one year. Of course, an engineering contingency may be in order. That is, it may be that distribution engineers believe that load growth may exceed 225 kW in a given year.

The key point is that installing 225 kW of storage allows the utility to avoid a one time charge of $150,000, or a one time, single year benefit of $150,000 / 225$kW_{storage}$ = $666/kW (of storage capacity, if installed). If the storage installed cost is that amount or less, then the storage plant pays for itself in one year.

Note that in California 10% of locations require distribution upgrades whose annual carrying charges are $80/kWc; that yields an annual deferral benefit of $1,067/kW of storage.

If the same storage system could be located to defer an upgrade 1) at a different location in a subsequent year, or 2) during a different season within the same year then benefits are additive (given appropriate time-value considerations).

T&D Equipment Life Extension

The benefit for T&D equipment life extension is quite similar to that for T&D deferral. To the extent that use of energy storage reduces maximum load and/or load swings on T&D equipment, the equipment's life may be extended. If so, the magnitude of the benefit is roughly the same magnitude as that for the T&D deferral.

Transmission Support

It is possible to use energy storage to improve the performance of the transmission system. For any given location, to the extent that energy storage support increases the load carrying capacity of the transmission system, a benefit accrues if additional load carrying capacity defers the need to add more transmission capacity and/or additional T&D equipment additional capacity is "rented" to participants in the wholesale electric marketplace (to transmit energy).

An earlier EPRI study that evaluated the use of SMES for such T&D support in Southern California during hot summer conditions, when the need is greatest and when the benefits are highest, the benefit was estimated to be about $170/kW. [8][27][26]

Transmission Access Charges Avoided

Utilities that do not own transmission facilities pay transmission owners for transmission "service." That is, when non-owners use the transmission system to move energy to and/or from the wholesale marketplace, owners must recoup carrying costs and operations and maintenance cost incurred. Related charges are often called transmission access charges.

One of the first Regional Transmission Organizations (RTO) to publish such charges is the Midwest Independent System Operator (MISO). Monthly and estimated annual transmission access charges that are expected to apply through 2007 for the MISO are shown in Table 2-2.[13][15] Annual values are estimated – for illustration only – by multiplying monthly values by 12.

A conservative value for this benefit is $10/kW-year for transmission capacity not used. Over ten years the NPV is about $72/kW. Based on the values in Table 2-2, a somewhat less estimate is $20/kW-yr or $144/kW.

Table 2-2
Summary: Transmission Access Charges for the MISO

	Access Charge ($/kW-month)		
	Low	Average	High
Monthly Charge (June 2003)	0.94	1.39	3.17
Transition Charge (=> 2007)	0.78	0.78	0.78
Total Charge	1.72	2.17	3.95

	Annual and Ten-Year Cost		
	Low	Average	High
Annual ($/kW-yr)	20.6	26.0	47.4
Ten-Year NPV ($/kW)	148	187	340

Source: Midwest ISO [13]

Reduced Cost for T&D Losses

This benefit accrues if there is a differential between T&D resistive (I^2R) losses on-peak when storage is discharged versus losses off-peak when storage is charged. As an example, if T&D I^2R losses are 8% on-peak and 5% off-peak the avoided losses are 3%. That reduces fuel use and related air emissions and reduces the need for generation and transmission capacity.

Electricity Supply Financial Benefits

Companies whose business involves electricity generation could derive several benefits from electricity storage. Some power plants cannot be turned off and restarted easily, so they run continuously, even if the value of the output is very low. For those plants, storage could be used to store low value energy for use when the value is high. Storage could be used to assist with “load following” so that generation plant output does not have to vary with load; the storage does the load following. Such load following adds wear and tear to power plants and may reduce efficiency and increase air emissions (per kWh generated). [5]

Arbitrage

Arbitrage involves purchase of inexpensive electricity available during periods when demand for electricity is low, to charge the storage plant, so that the low priced energy can be used or sold at a later time when the price for electricity is high.

To estimate the arbitrage benefit, a dispatch algorithm is used. It has the logic needed to determine when to charge and when to discharge storage, to optimize the financial benefit. Specifically, it determines when to buy and when to sell electric energy, based on time varying prices as well as the round trip efficiency of the storage system and the variable maintenance cost for storage operation. Actual chronological price data for the Pennsylvania, New Jersey, and Maryland (PJM) area is shown graphically in Figure 2-1.

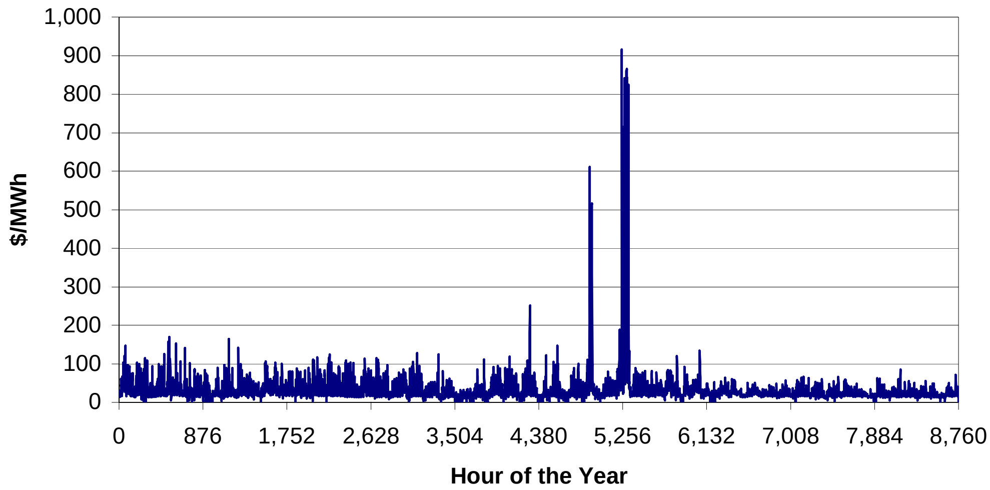

Figure 2-1
Chronological Price Data, for PJM, 2001

As shown in Table 2-1, in California arbitrage benefits are between $200 and $300/kW, net present value, for ten years, depending upon electricity prices, storage round trip efficiency, and storage variable maintenance cost.[18] [3]

Generation Capacity

If the installed base of electricity storage is large enough, the storage could be used in lieu of central generation capacity. Avoided are costs to own the power plant or cost to "rent" capacity in the wholesale electricity marketplace.

Historically, generation capacity has been bought and sold in the wholesale marketplace by utilities and more recently, by wholesale energy marketers. That marketplace is opening up to non-utility entities. A key development is access to the electric system's "wires" (transmission and distribution systems). Without such access, power from distributed energy storage (and generation) cannot be delivered to the electric system for sale.

Though difficult to generalize, as an upper bound, in many areas of the U.S. the most likely type of new generation plant "on the margin" is a natural gas fired combined cycle power plant costing an estimated $500/kW. Peaking capacity costs somewhat less. Applying a fixed charge rate of .13 to $500/kW yields an upper bound annual benefit of $65/kW per year, as indicated in Table 2-1.

Ancillary Services

It is well known that energy storage can provide several types of ancillary services. These are what might be called support services used to keep the regional grid operating. Two of the more familiar ancillary services are spinning reserve and regulation control. [17]

It is difficult to generalize benefits associated with ancillary services; the topic is complex, ancillary services have several manifestations, and even definitions of individual ancillary services vary among entities and regions.

The market for ancillary services is just being established, so there is limited history upon which to draw when trying to peg the benefit. The cost for many ancillary services is also quite volatile. Some vary over very short time periods and they are often location, time-of-day, and season-specific. For storage, the amount of ancillary benefits that may be realized is affected by discharge duration.

Actual values are usually posted by the regional transmission operator (RTO) or Independent System Operator. An example is found at the Midwest RTO. [14][15]

A conservative value for this benefit is $10/kW-year (NPV of $72/kW over ten years). However, based on posted prices for ancillary services for PJM and California, ancillary services benefits could be as high as $80/kW-year, assuming $16/MW-h for 5,000 hours of "service." (Note that providing that service does not require continuous storage output). [34][35]

Renewables

Electricity storage can enhance the value of energy from renewables generation in at least two fundamental ways. First, storage can "firm-up" renewables' output so that electric <u>power</u> (kWs) can be used when needed, not just when the renewable resource is available. This benefit is listed as renewables capacity firming in Table 2-1.

In addition, electric <u>energy</u> (kWhs) generated during times when the value is low can be "time-shifted" so that the energy can be sold when its value is high. One example is "contractual time-of-production payments" in California involving existing Standard Offer contracts. As shown in Table 2-1, in California this benefit is on the order of $650/kW, lifecycle, over ten years. [18]

Another option would be to charge storage with electricity from the grid as well as from wind generation. Specifically: if not enough energy available to charge the storage from wind generation then energy from the grid is used to fill-in. Relative to only using wind generation to charge storage, that allows for increased (storage) asset utilization and additional revenues, and provides more assurance that the storage is charged when wind is not present. [19]

Utility Customer Financial Benefits

Time-of-Use Energy Cost Reduction

For electric utility customers that pay "time-of-use" energy prices, storage may provide means to reduce their overall cost for electric energy. Customers charge the storage during off-peak time periods when electric energy price is low, then discharge the energy during times when on-peak (time-of-use) energy prices apply.

As an example, consider Pacific Gas and Electric's (PG&E's) Small Commercial Time-of-Use A6 rate structure, for entities with load of 500kW or less. It applies during the months of May to October, Monday through Friday. Energy prices are about 32¢/kWh on-peak (noon to 6:00 pm). Prices during partial-peak (8:30 am to noon and 6:00 pm to 9:30 pm) are about 15¢/kWh, and during off-peak (9:30 pm to 8:30 am) prices are about 10¢/kWh.

As shown in Table 2-1, the ten year NPV of benefit for storage used for this application is about $1,000/kW. Of course the benefit in any given circumstance (e.g. in other states) depends on the applicable rate structure. Also important are storage systems' round trip efficiency, variable maintenance cost, and reliability.

Demand Charge Reduction

Energy storage could be used by energy end-users to reduce their overall costs for electric service by reducing demand charges. Demand charges related to the maximum power draw of a facility (rather than the amount of energy used).

To avoid demand charges (associated with a given kW of peak load) customers must avoid using power during peak demand periods, which are the times when demand charges apply. Typically demand charges apply during late morning to late afternoon, during summer months, on weekdays. Load must be reduced for <u>all</u> hours during which demand charges apply: Often if load is present for just one fifteen minute period during when peak demand charges apply, the monthly demand charge is not avoided.

For this application the storage plant discharge duration is driven by the applicable tariff. For example, for PG&E's E-19 Medium General Demand-Metered TOU tariff, there are six on-peak hours (12:00 noon to 6:00 pm).

From Table 2-1, the ten year NPV of benefit for storage used for this application for PG&E's E-19 rate is about $465/kW. Note that the energy discharged to reduced peak demand also has value. In most cases the benefit associated with the energy may be added to the benefit related to demand charge reduction.

Electric Reliability

Energy storage is used to improve the reliability of electric service. In the event of a power outage lasting more than a few seconds the storage system provides enough energy to a) ride through outages of extended duration, b) to complete an orderly shutdown of processes, and/or c) transfer to on-site generation resources.

The discharge duration required is based on situation-specific criteria. If an orderly shutdown is the objective then discharge duration may be an hour or more. If an orderly transfer to a generation device is the objective then a few minutes of discharge duration is needed.

Based on a survey of available information, as shown in Table 2-1, a typical benefit might be on the order of $360/kW over ten years. [9][10][12]

On-Site Power Quality

Improving electric service power quality (PQ) involves use of electricity storage to protect loads against short duration power system anomalies that affect the quality of power delivered to electric loads. It has been estimated that poor power quality causes over $100 billion dollars in financial losses each year in the United States. [23][24]

Some manifestations of poor power quality which may damage or affect operation of electric loads include:

- Variations in voltage magnitude, e.g., short-term spikes or dips or longer-term surges or sags
- Variations in the primary 60 cycles/sec frequency at which power is delivered
- Low power factor (voltage and current excessively out of phase with each other)
- Harmonics, i.e., the presence of currents or voltages at frequencies other than the primary frequency
- Interruptions in service, of any duration from a fraction of a second to minutes

Typically the discharge duration required for the power quality application range from a few seconds to about one minute.

Though challenging to generalize, as shown in Table 2-1, the benefit for improved power quality can be as much as $700/kW over ten years. [9][10][12]

Combining Financial Benefits From Energy Storage

In many cases more than one benefit is required from storage for benefits to exceed cost. However, careful consideration of operational, technical, and market details is required before benefits may be added.

Operational Conflicts

Operational conflicts involve competing needs for a storage plant’s power output and stored energy. For example, storage providing power in lieu of a distribution upgrade deferral cannot be called upon to provide transmission congestion relief as well. Storage providing T&D support may not be capable of providing either enough power or power that is stable enough to serve the central generation capacity application.

Consequently, when estimating combined benefits it is important that the reader not add benefits from applications with conflicting operational needs.

Technical Conflicts

In some cases storage systems are physically unable to serve more than one need. One example is storage that cannot tolerate numerous deep discharges and/or significant cycling. These storage systems might be well suited to the T&D deferral application though they are not suitable for energy price arbitrage.

Another example is storage that cannot respond very rapidly to changing line conditions. Such systems may be suitable for energy arbitrage or to reduce demand charges but may not be able to provide transmission support or end-user PQ benefits.

Consider also storage system reliability. Less reliable (though lower cost) storage systems may be suitable for pursuit of energy arbitrage or time-of-use energy cost reduction benefits; however, such systems could not be used for demand reduction, T&D support, or T&D deferral benefits.

Market Intersections

As illustrated in Figure 2-2, the market potential for storage to be used for a combination of benefits – in the simplest case, two benefits – is the intersection of the market potential for storage used only for benefit type one, and the market potential for storage used for benefit type two.

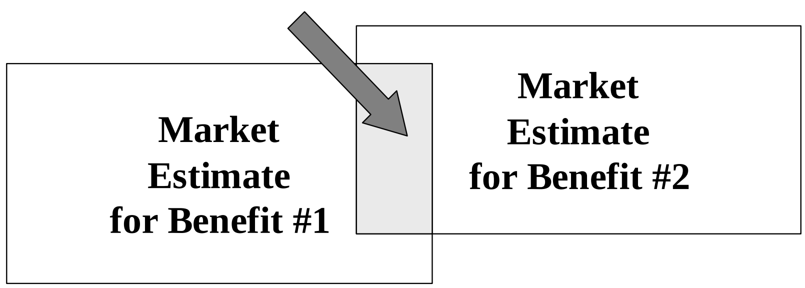

Figure 2-2
Market Estimation for Combined Applications/Benefits: Market Intersection

Consider an example: end-users will use energy storage for demand charge reduction, reliability enhancement, and improved power quality. Assuming that there are no operational or technical conflicts, the market estimates would account for the following:

- Technical market potential (as an example: 1,000 MW_{ac}) encompasses all commercial and industrial electricity end-users.
- However, only a minority (30%) of those end-users pay demand charges.
- For most commercial and industrial electricity end users that pay demand charges (60%), increased electric reliability is not a compelling issue.

- Only a portion of customers that pay demand charges and that are concerned with electric reliability (50%) will derive a financial benefit from improved power quality.

The resulting market potential is estimated to be:

$$1{,}000\ MW_{ac} * 30\% * 60\% * 50\% = 90\ MW_{ac} \quad \textbf{Eq. 2-1}$$

Qualitative Benefits

Strategic Value to Utilities

In addition to the quantifiable and in many cases monetizable benefits included in this chapter, storage may have softer yet even more important benefits on a strategic basis. The strategic value of storage is enhanced by its unique set of characteristics: flexibility, portability, and compatibility.

Flexibility

Storage can serve as a “shock-absorber” in at least two ways, first compensating in real time for imbalances between supply and demand, and second smoothing prices at each power purchase decision level, wholesale and retail.

The supply imbalance feature is exactly what is necessary to dampen power system oscillations such as those that may have contributed to the August 14th 2003 outage in the Eastern U.S. affecting 50 million utility customers and 41 GW of load. [33]

As an example of the market calming influence of storage, a small non-generating utility might use the existence of a storage device or group of devices to allow stronger negotiating for supply contracts or allow better terms in their long term supply contract.

Once built, a storage device can be operated at any power level (charging or discharging) up to its design limits (and occasionally beyond those limits). Any amount of energy can be stored or released within that limit without concern for excessive wear and tear on the device. In fact many storage technologies operate best at reduced charge or discharge rates.

A utility with substantial storage will be advantageous to new customers due to the resulting increase in electric service reliability. We may well see the proliferation of premium electric service “Power Parks” where every effort is made to assure end-user power quality and reliability; storage would be a critically important element of such Power Parks.

Portability

Some storage devices can be portable or at the very least relocatable, this opens up a world of applications and possibilities for utilities and customers alike.

A utility might own (or lease) a small fleet of storage devices, say a dozen, with each unit rated at a few hundred kWs and one hour of discharge at rated power. Such units can be combined to increase duration or power or both. They could also be used seasonally in utilities with regional summer versus winter peaks. Or the units could be loaned to customers with seasonal needs for added power or improved reliability. Similarly portable storage devices can cover for lack of utility power during planned or forced outages on distribution systems.

Compatibility

Storage can be used compatibly with renewables-fueled and other distributed generation, allowing the generators to be smaller (and hence more cost-effective), to operate at peak efficiency, and jointly to provide more reliability. If storage can achieve low enough costs it might become the hub of all distributed power installations.

Note that much of the work associated with integration of electricity generation and storage has been undertaken for what are generically referred to as hybrid systems. Normally these are not grid tied systems which have one or more generation source (e.g., reciprocating engines, photovoltaics, and wind generation) plus energy storage. [36] [37]

Storage can serve many other strategic roles. In emergency situations portable storage devices can be brought to the scene of the incident to supply power, even if fuel is not available for portable generators. During major public events, a utility may want to improve its public relations image by prominently supplying storage backup to handle unexpected power problems.

Grid Operations

In some cases energy storage may give grid operators additional tools to respond to significant power events or disturbances such as that in the Northeastern U.S. on August 14, 2003. For example, sufficient amounts of storage can dampen system oscillations which can give system operators additional time to respond to the events or disturbances. Though it is difficult to quantify a benefit, per se, clearly such a tool could have significant financial and other implications.

Customer Partnerships

For electricity storage to reach even a portion of its potential, in many cases beneficiaries will have to come together, to identify and to take advantage of win-win opportunities. These are situations for which electricity storage provides significant financial benefits, though benefits accrue to two or more beneficiaries. Ideally beneficiaries form partnerships which could be, for example, between the utility and end-users, between storage vendors or project developers and end users, or between energy services providers, the utility, and end-users.

The closer a storage system is to loads served, the greater the opportunity for such situations.

National Security

The U.S. Department of Energy's *National Vision for the Grid of the Future* recognizes multiple small distributed sources of energy, including electricity storage, as an important option to improve the robustness of the transmission system and to reduce the system's vulnerability to sabotage. [1]

For example, depending on how and where storage is located it may be able to compensate for downed lines. Or, assuming energy storage systems' controls can respond rapidly, a relatively small amount of bulk storage can have a significant effect on the stability of the transmission system when disturbances occur.

Electric storage can be used to provide "black start" energy needed to restart power plants that have been shut down during a major system disturbance.

Electricity storage can provide power to loads or even to local electricity distribution systems, relieving the burden on transmission and central generation systems as the grid is reactivated after a major disturbance.

Storage can provide backup power to critical loads such as hospitals, water facilities, and police and fire departments, the "first responders" to security and emergency situations.

Environmental

There are several possible ways that the environment can benefit from use of electricity storage. Perhaps most importantly, storage may lead to reduced fossil fuel use for and/or reduced air emissions from central generation. They include: 1) reduced use of less efficient fossil-fueled "peaker" generation with relatively high air emissions per kWh, 2) reduced need for generation to provide spinning reserve and load following, and 3) time-shifting of electric energy from intermittent renewable generation, making renewables more viable alternatives to fossil-fueled generation.

Depending on how it is used and where it is located, electricity storage could reduce the need for additional generation, transmission, or distribution facilities and land on which they would be built. Furthermore, if storage is located at or near loads then energy losses associated with T&D can be reduced.

Consider an example: storage is 1) charged during times when demand for electricity and T&D losses are relatively low (e.g., 5%) and storage is discharged when demand for electricity and T&D losses are relatively high (e.g. 8%). The net reduction is 3%, leading to 3% less fuel use and a corresponding reduction in air emissions.

Utility Asset Utilization

Asset utilization is the process of wringing maximum value from a capital investment by thoroughly and frequently using its full capacity. While most utilities are not rewarded directly for improved asset utilization or even increased reliability, in the long run utilities that spend their capital budgets wisely may well be looked on favorably by regulators.

A utility which is trying to improve its transmission and distribution asset utilization (much the way an airline will try to fill every seat on every flight) would be wise to avoid costly, irreversible investments such as feeder upgrades until the last moment. To continue the airline analogy, more planes should not be added until there is an almost certain demand for more seats.

Figure 2-3 shows typical utility asset utilization for central generation and distribution assets. [2] For both, the area below the curve indicates the asset utilization of each. Note the upper left end of the plot for the distribution asset. The sharp peak at the left end of the plot indicates that storage operating for a very few hours each year could easily delay the need for more distribution capacity, increasing asset utilization in the process. The opportunity is less compelling for storage used to offset need for generation, given the fact that generation's capacity factor and overall asset utilization is higher than that for distribution assets.

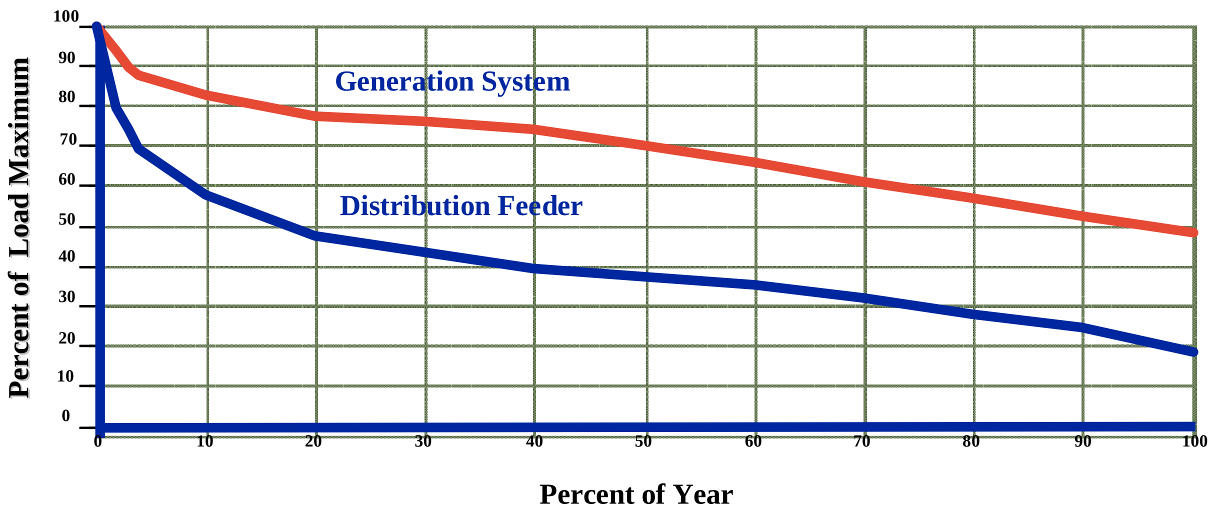

Figure 2-3
Load Duration Curve for Utility-Owned Generation and for a Typical Utility-Owned Electricity Distribution Feeder Circuit

A simple way to cost-effectively hedge distribution capacity would be temporary use of a storage device (on a year-to-year basis) while the distribution planner assures that the load projected for this feeder really occurs. Such a storage installation would not only handle the extra load on the feeder, it could be dispatched for regional supply shortfalls and/or during emergency situations. [3][16]

An even better way to manage feeder problems would be to monitor the load on each feeder at risk, to predict which of a dozen feeders may be closest to exceeding its rating this year. A fleet of portable units would be delivered to these sites a month or so before the problems are most likely to occur. Contrast this approach to the standard distribution upgrade "solutions" of 1) hoping that the utility can go through another year without serious consequences, but having no concrete plan in place which can be implemented in a matter of weeks (as storage can) or 2) preemptively upgrading the feeder by tens of percent when at most only a percent or two of capacity is actually needed to get through the year. Storage is flexible enough that exactly the right power rating of storage can be put into service, matching the load growth but no more; that is excellent asset utilization.

Electricity Cost Volatility Smoothing

Barring significant electricity price regulation electricity price volatility, especially during periods of high demand, seems likely. One possible way to managing effects of price volatility is to charge storage with low cost or low priced energy when demand is low, so energy can be used when demand and cost or price and volatility are high.

Storage Implementation Challenges

Storage Field Experience

Energy storage is not a new concept, either for energy end-users or for utilities.

Aside from use of batteries for consumer electronics, utility customers use batteries in the form of device-specific UPSs, facility wide UPSs, and even as part of emergency back-up systems, often in conjunction with on-site back-up generation.

As shown in Table 2-3, there have been more than 22 GW of central-generation-scale storage installed in the U.S. at more than 150 locations for utility purposes. Most utility experience with energy storage is with large, central-generation-plant scale facilities. Almost all of the installed capacity is large scale pumped hydroelectric storage. However, two compressed air energy storage (CAES) plants have also been installed and have operated reliably for several years. One began operation in Huntorf, Germany in 1978, and is rated at 290 MW_{ac}. The other, rated at 110 MW_{ac}, has been owned and operated by Alabama Electric Cooperative (AEC) since 1991 in McIntosh, Alabama. Both plants continue to operate well. [25]

Table 2-3
Summary: Experience With Energy Storage

Technology	Installed (U.S. total)	Facility Size Range	Commercially Available
Pumped Hydroelectric	22 GW at 150 facilities in 19 states -- almost exclusively utility-owned and operated	Up to 2.1 GW	*Yes*
Compressed Air Energy Strorage (CAES)	110 MW in Alabama (utility owned and operated)	25 MW to 350 MW	*Yes*
Batteries	More than 70 MW installed by utilities in 10 states	From 100 W to 20 MW	Conventional and Advanced Batteries *Yes*
Flywheels	Dozens of units. Increasing use as subsystems for onsite emergency back-up power systems.	A few kW to tens of kiloWatts	Steel, low rpm *Yes* Advanced composite *Near Commercial*
Superconducting Magnetic Energy Storage (SMES)	Numerous facilities with at least 100 MW of combined capacity in at least 5 states.	1 - 10 MW (micro-SMES) 10 -100 MW	micro-SMES *Yes* 10 -100 MW *Developmental*
Advanced or "Super" Capacitors	Millions of units for standby power. Emerging use: hybrid and electric vehicles	Watts to tens of kiloWatts	*Yes*

Source: U.S. Department of Energy, Energy Efficiency and Renewable Energy (EERE)[20]

Energy storage for T&D applications has been demonstrated, though on a limited basis and for limited circumstances. One of the most prominent examples is use of superconducting magnetic energy storage used in conjunction with a subtransmission system, by Wisconsin Public Service Corp. [4]

There has also been some experience with thermal energy storage. That involves use of electric energy to make and to store ice or to chilled water when demand and price for electricity is low. Instead of using air conditioning, when demand and price for electricity is high, the “coolth” stored is used for cooling.

Making a Storage Project Decision

Electricity storage system purchases should be evaluated just like any other investment, based on its economic advantages versus its costs. This can be done as a benefit cost ratio or as a comparison of the net present value of the projected benefits minus costs. The latter discounted cash flow approach is perhaps more standard than the benefit cost ratio, but both will give similar answers.

It is also possible, depending on the application being considered, that another technology may be more cost effective than the storage system, for instance distributed generation. In this case a discounted cash flow should be determined for that alternative investment also, and the best net present value selected with due consideration given to the different fuels used.

The financial parameters used should be the same a company would use to evaluate any other capital investment.

Status of Utility Planning With Storage

Electric supply-related benefits of energy storage can be modeled using production cost models. So-called chronological production cost models are used. Some of these models, including EPRI's DYNAMICS and DYNATRAN, are quite sophisticated. [32][33]

Evaluation of energy storage for T&D benefits is uncommon. One reason is that it is not nearly as straightforward to evaluate storage's technical viability vis a vis traditional T&D solutions. That is due, in part to complexities associated with storage system "dispatch" decisions and effects on storage equipment life and maintenance costs associated with charge-discharge cycles. Models used to evaluate electrical effects on circuits are intended to model circuits that include wires, transformers, capacitors, and loads rather than sources such as electricity storage.

Evaluating Storage Benefits and Costs

Many of the benefits associated with electricity storage described in this document are not currently included in the process when evaluating the financial merits of electricity storage. In general, there is limited experience and familiarity with electricity storage and its benefits. Even if benefits are understood, in most cases it is quite challenging to estimate the magnitude of the benefits for several reasons.

Most utility planning and electrical evaluation tools and financial and accounting evaluation criteria do not accommodate storage evaluations well. And even if utility benefits can be estimated, in many cases utilities may not claim or internalize them.

Many energy end-users are not familiar enough with potential benefits from storage or with related evaluation criteria to calculate potential benefits.

Storage equipment installed cost is somewhat straightforward to estimate. However variable operating costs, including maintenance and overhauls may be less certain and thus more difficult to estimate, especially for newer storage technologies. And, of course, there is uncertainty regarding the price for electricity used to charge storage plants.

With regard to plant capital cost, for each alternative being considered for a given project, utilities must estimate the annual cost of ownership. That requires use of, among other criteria, the financial life of the system – the number of years over which the system is depreciated. For most conventional utility solutions that value is pre-determined. In most cases there is no such "official" cost for storage solutions.

An engineer evaluating storage as an option must ask financial decision-makers to establish the financial life. Assuming that the financial decision-makers are also unfamiliar with storage, they too may have difficulty establishing the financial life of the storage system.

One possible reaction by financial managers who are not familiar with storage is to specify a short financial life (e.g., five to ten years) relative to other utility equipment such as poles and wires (30+ years). The result is that, all other criteria being equal, the annual carrying cost is much higher per dollar of storage plant cost than the conventional alternative.

A convergence of these factors would put electricity storage at a distinct disadvantage relative to conventional power solutions, even if storage is otherwise the best alternative.

Comparing Storage to Conventional Utility Alternatives

In addition to challenges associated with estimating lifecycle benefits and costs for electricity storage, traditionally utility T&D engineers use familiar, proven, and allowable evaluation techniques, tools, and solutions.

For example, a distribution engineer uses accepted evaluation practices and tools to determine how much additional transformer and/or wire is required to meet growing loads. S/he then specifies equipment from mostly standard elements and then determines labor requirements and cost using standardized approaches and values.

Beyond the fact that rules and standard practice rarely allow for storage as a T&D solution, currently T&D engineers have little or no experience with electricity storage and thus would have a difficult time specifying it as a solution. Furthermore, there is limited experience with and track record for storage for T&D applications for utility engineers to draw from.

Another significant challenge for <u>distributed</u> electricity storage and other distributed resources is that, some utilities may be discouraged from putting such facilities in rate base. Utility stockholders' dividends are derived from ownership of/investment in capital equipment. One implication is that distributed storage which could be the lowest cost option if <u>rented</u>, may not be used because rentals are either not allowed or because rentals may likewise reduce returns to stockholders.

Storage Versus Emerging Alternatives

In addition to conventional utility solutions, storage will have to compete with an array of emerging alternatives. Depending on the application for which storage is to be used, these emerging alternatives include technological and economic (market-based) options.

Technological

A key competitor to storage – excepting bulk/supply plants – is distributed generation (DG). Though DG has some significant inherent disadvantages – primarily related to air emissions and to a lesser extent, noise and fuel cost – in some circumstances DG is likely to be the competitive option. DG tends to be more competitive if power is needed for only a small number of hours per year and in locales for which air quality is not a significant issue. DG systems tend to be more mobile than storage systems.

Another competitor to electricity storage for T&D applications is what could generically be called "smart" T&D. That includes an array of state-of-the-art and emerging options for improved monitoring, control, and overall management of T&D systems. In some cases such improvements may be alternatives to storage. In other cases they may complement storage.

Another possible alternative to storage may be called Demand Side Management (DSM) aggregation. Consider an example. A given utility area has overloaded circuits. The utility or and ESP contacts industrial and commercial end-users asking end-users if they will accept a discount on their electricity bill in return for the right to turn off designated equipment for a specified number of hours per year. Using state-of-the-art control systems all such loads can be coordinated as a block. When circuits become overloaded, the block of power may be called upon to reduce the load.

Of course, the same could be done with energy storage, or even a combination of storage of DSM.

Economic

Economic or market-based solutions involve use of "price signals" that are designed to change demand as needed for a specific situation. A simple example is time-of-use energy pricing; it is designed to discourage use of electricity when cost is high.

Transmission congestion charges comprise another example. They are applied when demand for transmission capacity exceeds capacity. In the context of this document, congestion charges are an alternative to storage to be used to defer a transmission upgrade.

There are many possible manifestations of such market-based alternatives. The extent to which utilities may use such innovative market-based approaches is uncertain.

Regulatory Approaches and Monetization Mechanisms

Storage applications in the U.S. are hindered as much by unfamiliarity and conventional business practices as by technical risk or economics. Utilities have yet to fully explore the wide range of applications which are already technically feasible, and regulations (and hence business practices) are not designed for rewarding the broad range of storage benefits. For example, fire inspectors may be unfamiliar with some storage technologies, leading to additional storage project compliance costs and/or delays.

Many of the benefit streams described in this chapter while mathematically correct and economically accurate, are not yet the norm in terms of regulatory treatment. For example while many experts might agree that installing a small storage device on a feeder is the operational equivalent of doing a small, low-risk wires upgrade, it is not clear who has the right to install that storage device and who can get financially rewarded for doing so. The ownership issue is an excellent example of regulatory uncertainty. The financial aspect is generally called monetization, how much money can and will flow from one party to another, and by what mechanism.

Regulatory Issues

As an example, in some states utilities are no longer allowed by regulation to participate in the generation supply business, they are only to manage the wires. A storage device is neither a generator nor a wire, making it unclear if it could be placed into rate-base or not. Until such basic regulatory issues are resolved, a utility will be justifiably hesitant to invest in a storage device for such applications.

On the customer-side-of-the-meter, a customer might reduce its demand charge by purchasing energy off peak and discharging storage when its internal electric consumption (or the demand charge) is highest. Depending on the level of the demand reduction, the utility might not have a specific tariff which fits this situation. In one state such use of storage might be seen as a simple demand reduction action by the customer, and might even be rewarded in some way. In other states this might be considered an exiting load requiring a standby charge nearly equal to the avoided demand charge. In yet other states the tariff might provide for a ratcheting of the demand if the storage device failed to work as designed for just a few minutes per year. While each of these regulatory treatments has good underlying rationale, related uncertainty regarding regulatory treatment currently impedes broader adoption of storage. The non-standardization of utility rates and treatment impedes the development of a national scale market. It is still possible, however that each location must be evaluated individually.

Monetization

With regard to monetization, and once again considering the distribution upgrade deferral opportunity, a utility may or may not be rewarded by its regulators for improving asset utilization or reliability by using storage. If the utility is rewarded the monetization could take the form of rate-basing the storage device (or a portion of the device) for every year it is in service.

Depending on the form of rate-basing, utilities could even improve their profitability if the storage device is employed successfully as an alternative to (or hedge against) expensive wires upgrades.

Another monetization issue arises if a customer installs a storage device and requests payment for deferring the utility’s need to upgrade a feeder. Setting aside the requirement that the device be dispatched to perfectly meet the utility’s needs on the feeder, how much should the customer be paid to provide peak clipping services, and in what form on what schedule? How much risk does the customer bear for perfect storage operation and how does the utility mitigate that risk. It would seem that these issues could be handled via a performance contract between the customer and the utility with reasonable expectations of storage reliability.

Customer benefit monetization is not really an issue when the customer installs the storage device for their own needs. Either the customer has determined it is in their best interest to install a storage device, or it isn't. For example, since most storage is likely to be in place to mitigate reliability and power quality problems, it would be assumed that the customer has already evaluated the tradeoff between the cost for the storage and the cost of associated power problems. The financial rewards of installing storage will accrue as losses due to outages and power quality events are avoided.

Permitting and Siting

As with many types of projects, depending on scale, location, processes, and other criteria, energy storage projects are subject to many institutional challenges that fall into the general category of permitting and siting.

For any particular circumstance, permitting and siting challenges for storage projects may include:

- Zoning
- Environmental Impact Studies
- Use Permits
- Building Permits
- Hazardous Materials: storage, handling and compliance
- Fire-related: rules, compliance and inspections
- Emergency Planning (e.g. evacuation routes and plans)
- NIMBY

Because most utility-related energy storage solutions are not common, siting and permitting decision-makers tend to have limited familiarity with them and thus, may make unnecessarily conservative siting and permitting decisions.

Of course, most alternatives to energy storage face their own set of these challenges. For example, distributed generation's air emissions pose a significant permitting challenge in many areas whereas emissions into the air from most storage processes tend not to be an issue. (Some types of energy storage do have emissions which may pose a unique permitting and siting challenge.)

Though lead acid batteries are commonplace some storage technologies employ less common chemicals or rapidly spinning hardware. Until local permitting officials become more familiar with these materials and operations, permitting and siting may be slow. For a review of current siting and permitting issues for battery installations see the paper entitled *Battery codes and standards: Changes in 2002 and 2003* presented at the 2003 BatCon conference. [30]

National Perspective on Energy Storage

National Markets and Economic Benefits

Estimates of market potential (in units of megawatts--MW or gigawatts--GW) for storage equipment in California are shown in Table 2-1. Market potential is shown for each type of benefit. Also shown are estimates of the possible economic benefits ($Million) associated with the market potential for respective benefit types. (For more on details about the rationales used to estimate these market potential values please see reference 18.)

Consider an example. The estimated lifecycle benefit for central generation capacity in California is estimated to be about $215 per kW of storage over ten years. For a market potential in California of 3,200 MW the economic benefit is about $688 Million.

Table 2-4 contains financial benefits (per kW of storage), maximum market potential, and ten year economic benefits (calculated as financial benefits multiplied by market potential) for California, from Table 2-1.

For context, Table 2-4 also includes estimates of market potential for and potential economic benefits for the entire the U.S. They were made, based on the California values, using a scaling factor of eight. That number is derived from three econometric/demographic criteria. They are the ratio of national to California values for: 1. population, 2. federal income tax revenues, and 3. economic activity. The scaling factor of 8 is the weighted average value of those three ratios.

Arguably, econometric and demographic criteria are not the most appropriate ones to use for scaling, relative to electricity-use-related criteria. Indeed, based on per capita electricity use the U.S. market potential would be 17 times larger than that in California. [37]

For context, the current installed capacity of utility generation in the U.S. is about 900 GW. [39]

Table 2-4
Benefits, Market Potential and Economic Value Estimates

		California		National***	
Benefit	Ten Year Lifecycle Financial Benefits ($/kW)*	Maximum Market Potential (MW)**	Ten-year Economic Benefits ($Million)	Maximum Market Potential (MW)**	Ten-year Economic Benefits ($Million)
Distribution Upgrade Deferral Top 10th. Percentile of Benefits	1,067#	160	172	1,280	1,373
Time-of-Use Energy Cost Management	1,004	4,000	4,021	32,000	32,166
Power Quality Reduced Financial Losses	717	4,000	2,872	32,000	22,973
Distribution Upgrade Deferral 50th. Percentile of Benefits	666#	804	536	6,433	4,284
Renewables Contractual Time-of-Production Payments	655##	500	328	4000	2,620
Transmission Upgrade Deferral	650#	1,100	710	8,800	5,680
Demand Charge Management	465#	4,000	1,862	32,000	14,897
End-user Electric Service Reliability Reduced Financial Losses	359	4,000	1,438	32,000	11,501
Bulk Electricity Price Arbitrage	200 to 300	735	147 to 220	5,880	1,468
Central Generation Capacity (Avoided Cost or "Profit")	215#	3,200	688	25,600	5,504
Renewables Capacity Firming	172#, ##	1,800	310	14,400	2,477
Transmission Support (Avoided Cost or "Profit")	82#	1,000	82	8,000	656
Ancillary Services (Avoided Cost or "Profit")	72#, ###	800	58	6,400	461
Avoided Transmission Access Charges	72#, ###	3,200	230	25,600	1,843
Avoided Transmission Congestion Charges	72#, ###	3,200	230	25,600	1,843

*In California
**Over ten years, based on lifecycle benefits times maximum market potential (market estimates will be lower).
***Ratio U.S. Market Potential / California Market Potential is assumed to be 8.
#Does not include incidental energy-related benefits or costs, if any.
##Wind generation.
###Placeholder values. The actual benefit was not estimated.

Broad National Role for Electricity Storage

The discussions above on applications and benefits barely begin to scratch the surface of the ultimate role that storage could play in a broad view of the utility of tomorrow. Individual benefits and even multiple benefits from a single device are good, but a more holistic view of the utility of the future leads to much more profound role for storage, especially as performance and cost improvements continue to be made.

In the broadest sense, storage devices may be the most important element of the power systems of the future. Storage devices, if inexpensive enough and reasonably efficient, would be of highest value if placed at or near customers with variable loads. The second best location is on utility feeders, followed by substations and the transmission system. If these devices are operated for the common good, the wires could be nearly base-loaded and the reliability of the system as a whole would be much improved. [7]

While this chapter has addressed utility and customer applications of storage, customer-utility partnerships may be even more important. Since storage is so flexible in siting and operation, either party could own a device and yet operate it to their mutual benefit. Performance contracts would be a reasonable way to manage the economic transactions.

Energy Service Companies (ESCO) could also have an important role using storage. The customer-utility partnerships mentioned above could be facilitated by a third party who contracts with the customer and the utility. While deals could be designed in many ways, the ESCO could own and operate the device, guarantee its operation, and serve as an aggregator of many such devices. Such aggregation may allow the regulators to allow tariff design more acceptable to storage device owners, for instance allowing for rare failures to reduce demand levels, while keeping the aggregate demand of a group of customers below some limit. In general, the advent of a storage opportunity for ESCOs would remove hassle and market hurdles for storage.

There are opportunities for National security enhancement with storage. As has been shown on August 14, 2003 in the East and Midwest, the utility grid is not immune to major outages. While the recent outage was not caused by sabotage of utility operations, the same effect could have occurred due to terrorist actions. Storage could have played a major dampening role in the recent outage, as could have distributed generation. With its multiple benefits and easy siting, storage could have dampened the oscillations in a system, lessening the need to trip generators or drop load. The devices could earn standard benefits during times of normal operation.

If storage were used to protect sensitive customer loads national productivity would improve. EPRI has estimated that the annual lost productivity due to shorter duration power quality events and service disruptions is at least $53 Billion per year (in 2001). Losses due to outages and disruptions of all types are about $119 Billion (2001). There is an increasing societal need for better power quality and reliability due to an expanding digital economy. [23][24]

While storage does not create electricity it can nonetheless have an important role in pollution mitigation. Large power plants are almost always dispatched based on their incremental cost of energy production. As load increases during a day, more expensive power is brought on line. These plants need to be ready to respond quickly (contractually and physically), this entails literally warming up the units in many cases hours before any power is needed. Not only is this a waste of fuel, it causes extra emissions. Storage could be used to reduce the need for much of the warm standby of power plants.

A similar situation involves partial loading of power plants. Generating plants are designed to operate at or near peak output. Plant air emissions increase and fuel efficiency drops when plants operate at part load. Again storage can be used to allow plants to operate as designed, storing excess energy or discharging during under-supply conditions, for reduced air emissions. (This does not include consideration of storage efficiency. Losses associated with energy storage will partially offset emission reductions from generation.)

Based on EPRI's Energy Storage Roadmap, developed in early 2003, EPRI envisions a future (2025) when energy storage capacity is equal to 10% to 20% of the installed generation capacity (up from 2.5% in 2003). As part of that capacity, some would be installed at transmission hubs, in part, to increase transmission line current carrying capacity by 10 percentage points (from typical values of 40% to 50%). Similarly use of storage at distribution substations and on circuits could increase distribution system asset utilization by 15 percentage points; current levels range from 35% to 45%. [2]

Societal Perspective

The utility business as it now stands is based on averaging. The demand and energy rates a customer pays are negotiated values based on past and projected utility costs and customer type consumption patterns. Typically within a utility each customer type (residential, commercial and industrial) is offered identical rates based on these averages, glossing over the locational differences in providing that power and energy, and the individual needs of each customer for better or worse reliability and/or power quality.

This ratemaking approach is simple enough but overlooks the opportunity to have rates track true utility costs, and to bill each customer more accurately. If utility rates tracked costs, the true value of distributed electricity storage would be much more obvious. If there were planning, operational and regulatory treatments which began to include these real effects, storage would be much more valuable and hence much more in demand.

The utility of the future is almost certain to be more information intensive. Looked at historically, Edison's first Pearl Street Station only needed to know its own status and whether it was truly connected to its customers or not. As the size of power plants grew more data was needed to operate the plants efficiently. When transmission systems began to link these plants to more distant load centers, even more information needed to be processed to coordinate plant power levels and consumption locations. The utility of the future will require this type of coordination and much more. Not only have changes in regulation brought more players into the game (independent power producers, energy service companies, etc.), the data intensive nature of business itself has demanded digital quality power to critical loads. Storage has a very valuable role in responding to real time adjustments needed to keep the data intensive power systems of the future operating reliably and efficiently.

Market Conditioning and Research Needs and Opportunities

Market Conditioning Needs

For storage to be a substantial part of the power system, certain changes may need to be made in how the marketplace rewards or allows storage to participate. No subsidies are needed; what *is* needed is a marketplace which recognizes and monetizes the extra benefits storage can deliver. The following would be advantageous to storage and many other emerging technologies:

1. Favorable field experience with storage systems. As research and development projects demonstrate the safety and effectiveness of storage systems, potential users will feel more comfortable specifying their use.

2. Storage devices allowed into utility rate base for all applications. Utilities should be allowed to use (and recover costs from) storage devices as they would wires or transformers.

3. Tariffs which differentiate by quality of service and location, and recognize the cumulative benefits of multiple devices. If customers begin to pay for improved power quality or reliability, the value of storage systems becomes obvious. Similarly, if customers are providing benefits to utilities due to their storage systems, the utility should be encouraged to share those benefits. Tariffs should be designed to minimize penalties for customers solving their own problems.

4. Commercial and regulatory environment that allows the sharing of benefits by multiple organizations. Without the ability to write the performance based contracts referenced above, storage will probably remain a niche product.

5. Tax credits or incentives that reward the grid security and reliability increases due to storage.

6. A fungible market for "upstream" benefits such as transmission and distribution support, generation capacity, ancillary services and line loss reductions. While many storage benefits are real, very few mechanisms exist to reward the owners of systems for the benefits they provide. The transaction costs of rewarding benefits need to be reduced.

R&D Needs and Opportunities

Storage is not a common element of today's power systems, yet its promise is obvious. What are the barriers to storage entering the power system and providing sizable benefits to utilities, customers and society, and what research and development activities do those barriers indicate?

As with many emerging technologies, storage presents a chicken and egg problem. If storage devices were much less expensive, more efficient and had proven reliability and applicability, their path to market would be easy. In the absence of those features, there is little incentive for an individual storage technology developer or utility to lead the way in solving all of those problems alone, hence there is a natural role for broadly supported, both government and private, research and development.

Storage for power applications may be on the verge of synergy with transportation applications. The economies of mass production for medium sized storage technologies and applications may be hastened by the transportation sector. Not only standard car batteries but also cutting edge technologies are emerging as part of hybrid, electric and hydrogen powered vehicles. Advanced power electronics cost and performance are likely to advance quickly once these transportation markets begin to grow.

The following is a listing of key R&D needed for energy storage to flourish based on sound technical and financial criteria. There are four categories:

- Technology Improvements
- Field Tests (to make market entry and early adoption less risky)
- Planning Models Incorporating Storage and Storage Evaluation Tools
- Validation and Verification of Technical Criteria Affecting Energy Storage Benefits

Technology Improvements

Key Objectives: reduced storage capital and variable operation cost, sophisticated operations.

Though storage technology may indeed be a commercially viable solution in a growing number of circumstances, there are additional technology-related R&D developments which will affect storage's overall viability. Examples include improvements that make storage: a) less expensive to manufacture, b) less expensive to install, b) less expensive to operate, and d) easier to control and operate under a range of circumstances, needs, and conditions. Improvements are needed in:

- System integration, leading to the existence of full turnkey storage systems with plug and play capability, for the smaller systems
- Scale-up of prototype devices to full application sizes
- Development of modular storage designs and demonstration of aggregation
- Development and improvement of the supporting technologies (i.e. power electronics, advanced storage devices, control systems, etc.)
- Development of high voltage, high power, combinations of modular storage devices (e.g. electrochemical capacitor modules, flywheel arrays, improved understanding of the string behavior of batteries)
- Long term, basic research on storage technologies to improve life time, energy and power density
- Capital cost reduction especially at mass production levels

- Full understanding and reduction of operations and maintenance costs eventually leading to warranties and performance guarantees
- Energy storage efficiency improvements
- Proven reliability of system performance
- "Smart" network control systems
- Certification, e.g. by UL and IEEE

Field Tests

Key Objective: make market entry and early adoption less risky.

Before energy storage is embraced as a mainstream option, potential users must have some sense of the risks. One key source of knowledge needed to ascertain that risk is actual experience with storage under realistic conditions. To date there is a dearth of such field experience with storage used for several important benefits, especially distributed benefits and benefits associated with transmission operations.

The following is a listing of the types of field experience needed for a broad selection of storage technologies and applications:

- Validation of system performance (efficiency, variable operations and maintenance, reliability, projected lifetime)
- Confirmation of system costs
- Improved visibility of storage successfully solving real world problems cost-effectively

Planning Models Incorporating Storage and Storage Evaluation Tools

Key Objective: enable credible evaluation of storage as an option.

Utilities, utility regulators, and non-utility third parties all use models to evaluate needs for and effects from various power technologies. For example, utilities use models to optimize their electric resource mix and power engineers evaluate electrical effects of various circuit configurations and contingencies. For the most part, these models do not accommodate storage well. An important way to enable broader use of storage is to develop means to evaluate its financial and electrical effects.

The following is a listing of possible model-related R&D:

- Development of certified storage dispatch algorithms to maximize benefits
- Development of improved utility planning models (generation, transmission and distribution) which include storage as an option

- Development of improved utility operational models (generation, transmission and distribution) which include storage as a component
- Analysis of combination of benefits to assure additivity and physical and business compatibility
- Full understanding of storage value propositions, market potential and commercialization pathways, for all utility and end-user market sectors and applications
- Credible and thorough understanding of storage costs versus performance tradeoffs
- Development of innovative market rules which allow the value of storage to be seen in the marketplace (tariffs, regulatory treatment, etc.)
- Development of streamlined siting and permitting for storage

Validation and Verification of Technical Criteria Affecting Energy Storage Benefits

Key Objective: provide confirmation of benefits using monitoring, measurement, and analysis of technical criteria.

An important challenge for early adopters of electricity storage (for less familiar applications) is the need to develop a credible, defendable estimate of benefits. Without tools or field experience this is difficult. So, in addition to model and field testing R&D listed above, it is also important to provide means to include, measure, and validate all benefits associated with use of electricity storage.

These are the types of activities needed:

- Credible and quantitative inventory of storage benefits
- Field validation of quantitative benefits of storage systems, for a broad selection of storage applications and benefits
- Field confirmation of qualitative benefits of storage systems, for a broad selection of storage applications and benefits
- Reduction of barriers to monetization of benefits

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Additional Resources

Electricity Storage Association, Includes Links to Vendors
http://www.electricitystorage.org/

Electric Power Research Institute
http://www.epri.com/targetOpps.asp?program=262246

Energy Storage Council
http://www.energystoragecouncil.org/

Electric Energy Storage – Applications and Technology (EESAT) 2003 Conference (with links to past Conference Proceedings)
http://www.sandia.gov/eesat/index.htm.

Sandia National Laboratories, Energy Storage Systems Program Website
http://www.sandia.gov/ess/Links/links.html

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http://www.eere.energy.gov/EE/power_energy_storage.html

United States Department of Energy Department of Energy, Office of Power Technologies (OPT)
http://www.eren.doe.gov/power

United States Department of Energy, Office of Electric Transmission and Distribution (OETD).
http://www.electricity.doe.gov

3
T&D APPLICATIONS FOR BENEFIT – COST ASSESSMENTS

This chapter describes the T&D applications for energy storage addressed in this Handbook. Single function applications are identified within four broad categories – Grid Stability, Grid Operational Support, Distribution Power Quality and Daily Load Shifting – and a tabular summary of top-level energy storage system requirements is provided for those applications. Note that other utility-scale energy storage applications exist, but which are generally identified with the generation sector or the end-user sector. A prominent candidate in the former category is wind power stabilization and/or optimization that can also involve the T utility. For the latter category, there are many large end-user applications that could involve the T or D utility. An example is starting-up and stopping electric trains, with the opportunity of power demand reduction and energy recovery via regenerative braking. Such applications may be added in future updates and expansions of the Handbook.

The energy storage technologies addressed in this Handbook are also introduced and correlated with both single and combined function applications for which they are deemed best suited. The suitability of technologies for applications is based on technical attributes and benefit-cost assessments presented in the respective energy storage technology chapters.

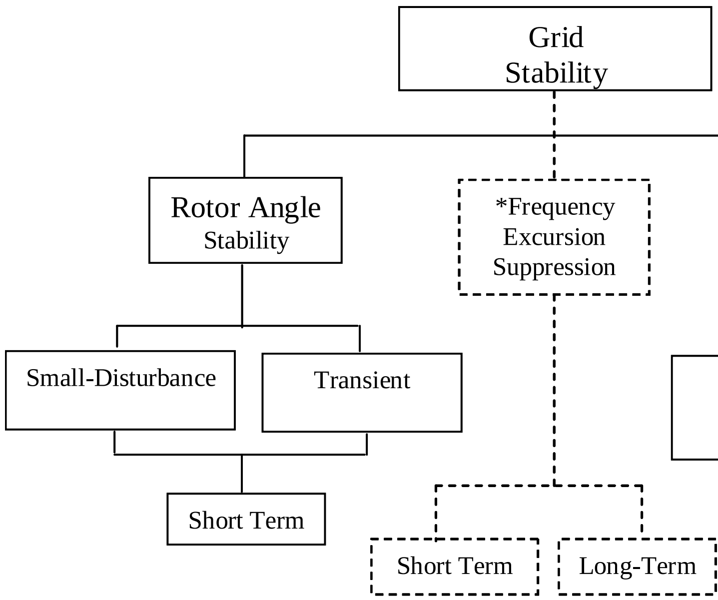
Description of Single Function T&D Applications for Energy Storage

Grid Stabilization

Grid stability is the ability of a transmission grid to regain a state of operating equilibrium after being subjected to a disturbance, so that essentially the entire system remains intact. Grid stability is classified in Figure 3-1 on the basis of the following considerations (adapted from [1]):

- The physical nature of the potential instability
- The size of the disturbance considered
- The time intervals needed to establish stability

In the daily operation of any grid power system, overall system security as well as local reliability requirements are determined so as to guard against thermal overload and/or instability in the event of credible contingencies. Based on the accepted NERC criteria (which may vary by region, e.g., the Western Electricity Coordinating Council (WECC)), a credible contingency may include the forced (unplanned) outage of a single major element such as a line, transformer, or on-line generator (n-1 contingency), simultaneous outage of two major elements (n-2 contingency), and in rare cases, outage of more than two elements (cascading events). Often, these security and reliability requirements result in the transmission system being operated at a level below its rating, resulting in corridors of constrained power flow, or "bottlenecks."



*Frequency Excursion events can challenge operational equilibrium, but are not characterized via classical stability analyses in the manner of Rotor Angle and Voltage Stability.

Figure 3-1
Classifications of Modes of Grid Stability

Accordingly, stored energy strategically introduced within the overall grid can potentially alter the definition of credible contingencies such that the transmission capacity of the system is increased. Rotor angular stability, frequency excursion suppression and voltage stability are characterized below for later use in evaluating the economics of alternative energy storage media that are deployed as a means of increasing transmission or distribution system capacity and reliability.

While thermal overload is a quasi-steady-state phenomena (10s of minutes); angular and voltage instability are dynamic phenomena (a few to 10s of seconds). Under steady-state conditions both before and after a contingency, transmission line flow levels and substation voltages must stay within specified limits. Even if a feasible post-contingency steady-state condition may exist, instability may prevent transition to such a state, and result in loss of synchronism, cascading outages, or voltage collapse.

Rotor Angle instability occurs when a fault (e.g., short circuit) occurs on a transmission component that initially causes one or more generators to accelerate, leading to weakly coupled electromechanical oscillations with other generators on the grid. If such generator oscillations are not damped, an unstable operating condition may emerge as generators lose synchronism with the grid and trip off line. In addition, if other transmission equipment fails, affected circuits may overload and in turn may trip out of service, which then leads to more overloads and potential system instability.

Voltage instability can occur when a load and the associated transmission system require a large amount of reactive power (compared to the real power component of the load), exceeding the capability of available reactive power sources. Under this condition, an increase in load is accompanied by a drastic voltage drop and the voltage "collapses." This condition is usually caused by contingencies leading to (generally localized) high power flows that create an increased demand for reactive power due to increased line loadings.

Frequency Excursion Suppression can occur following a severe system upset resulting in a significant imbalance between generation and load. Generally, problems related to frequency are associated with inadequate equipment response, poor coordination of control and protection, or insufficient generation reserve. Such problems can be brought on by market circumstances, such as contracts with provisions for abrupt power supply and termination.

Any of these conditions can lead to system segmentation and/or failure, and interruption of service to customers. While all are interdependent system-wide phenomena, angular instability and frequency excursion events can be thought of as "generation-driven", and voltage instability as "load-driven", in that the initiation of unstable conditions and the processes for event mitigation tend to be dependent on, or particularly sensitive to those component properties. While systems with highly meshed networks are predominantly constrained by combinations of voltage stability and thermal limits, systems with load centers and generation separated by long distances are more likely to be limited by combinations of thermal and angular stability limits. Also, these phenomena are not isolated events, and may occur concurrently and/or be interrelated. The August 14, 2003 Blackout for a major area of the East and Midwest highlights this complexity and the importance for improved systems and procedures to manage the grid.

In the context of transmission and/or distribution utility stakeholder economics, it is important to note that the requirements for energy storage to mitigate the consequences of these events are dependent on the location within the grid that the remedy can be introduced. For example, in most cases, angular instability contingency events could be mitigated by mechanical means (e.g., fast acting pressure relief valves, power stabilizers, etc.) introduced proximate to the affected generators. Likewise, in most cases, voltage instability limits can be addressed by providing additional reactive power resources proximate to critical loads. However, access to proximate sites and the means for investment recovery may not exist for the transmission and/or distribution utility whose transmission capacity is constrained by these contingencies. Expansions for each of these instability phenomena follow. The foregoing was adapted from [2].

Rotor Angle Stability

The relative angular positions of rotors of synchronous machines remain constant (synchronized) when no disturbance is present. If power flows in an interconnected transmission system change too much or too suddenly (such as loss of a major transmission line), some machines may lose synchronism. One type of rotor angular instability is long term dynamic instability, which results in undamped electromechanical oscillations. Such electromechanical oscillations may involve a number of generators widely separated geographically (inter-area oscillations) and may appear when system loading is increased across a weak transmission link. If not controlled, these oscillations may lead to total or partial power interruption. For example, for heavy power transfers from East of the Colorado River (EOR) to California, one of the critical disturbances that results in undamped electromechanical oscillations is a three-phase fault at the Palo Verde 500kV bus followed by the loss of the Hassayampa - North Gila 500kV line. This line, near the Colorado River, is one of the major tie lines between Arizona and Southern California. This is generally the limiting contingency when determining Southern California import capability. Moreover, the import capacity is affected by the amount of generation on-line within Southern California. Figure 3-2 illustrates oscillations for a "marginally damped" loading combination (solid line) and for an undamped condition caused by only a $10MW_{ac}$ load increment West of River (WOR) (dashed line). If unchecked, such an undamped condition would lead to system breakup (i.e., further tripping of lines or generators) [3].

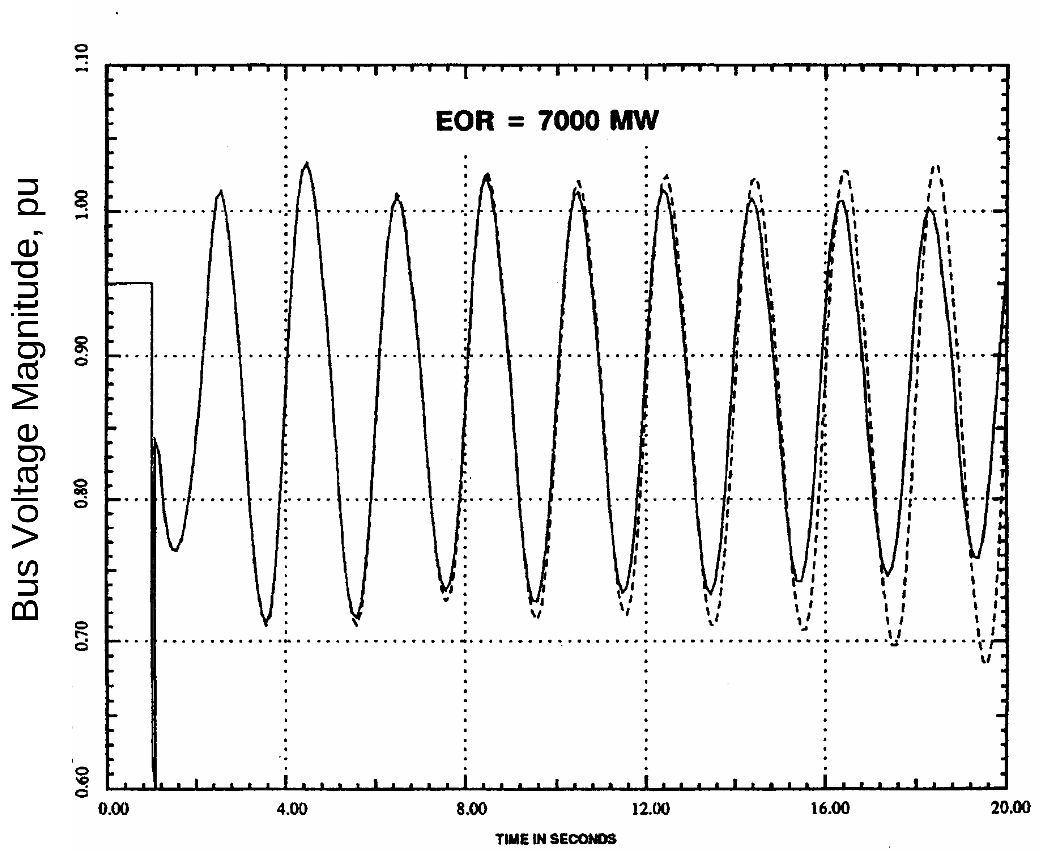


Figure 3-2
Southern California Intertie: Marginal Damping and Effects of 10MW Load Increment

As previously noted, in some system configurations, angular oscillations can be controlled by electromechanical devices at the generation plants, e.g., fast relief valves, power system stabilizers, etc. Other circumstances may benefit from switching stored energy between charge – discharge modes at the frequency of the oscillation (e.g., 0.5 to 1.0 Hz) over a period of a few

10's of seconds. This type of solution with superconducting magnetic energy storage (SMES) has been studied extensively by West Coast utilities. Other technologies, including ultracapacitors, flywheels and some batteries may also be suitable.

Since limits on Southern California Import Transmission (SCIT) are established on the basis of, among other things, the inherent inertia of the generation on-line [4], another possible strategy to address rotor angle instability contingencies is to introduce a "prompt spinning reserve" (PSR) energy storage system that enables conventional spinning reserve generation to be brought on-line, thus increasing the available transmission capacity (see further discussion of PSR in the next section). This strategy to utilize energy storage is similar to that considered by ISO-NE to address voltage instability conditions as described in the section titled Voltage Stability.

Frequency Excursion Suppression

Frequency excursion suppression provides the power grid system the ability to maintain steady frequency within a nominal range following a severe system disturbance caused by, or resulting in, a significant imbalance between generation and load. Stable operation depends on the ability to quickly restore balance between system generation and load, with minimum loss of load. The excursions that may occur in the form of sustained variances of system frequency from normal, leading to tripping of generating units and/or shedding of loads.

Severe system disturbances generally result in large excursions of frequency, power flows, voltage, and other system variables, thereby invoking the actions of processes, controls, and protections that are not modeled in conventional transient stability or voltage stability studies. These processes may be very slow, such as boiler dynamics, or only triggered for extreme system conditions, such as volts/hertz protection tripping of generators. In large interconnected power systems, this type of situation is most commonly associated with "islanding" (i.e., a condition in which a portion of the utility system that contains both load and generation is isolated from the remainder of the utility system). Operational stability in this case is a question of whether or not each island will reach a state of operating equilibrium with minimal loss of load. It is determined by the overall response of the island as evidenced by its mean frequency, rather than relative motion of machines. Generally, problems related to frequency are associated with inadequate equipment response, poor coordination of control and protection, or insufficient generation reserve.

Over the course of a frequency excursion event, the characteristic times of the processes and devices that are activated by the large shifts in frequency and other system variables will range from a matter of seconds, corresponding to the responses of devices such as generator controls and protection, to several minutes, corresponding to the responses of devices such as prime mover energy supply systems, load voltage regulators and load shedding controls.

Frequency excursions may be impacted by fast as well as slow dynamics, and the overall timeframe of interest may extend from several seconds to several minutes. Therefore, as noted in Figure 3-1, frequency excursions may be a short-term phenomenon or a long-term phenomenon. An example of short-term frequency instability is the formation of an under-generated island with insufficient load shedding options such that frequency decays rapidly causing blackout within a few seconds. On the other hand, more complex situations in which frequency excursions are caused by steam turbine overspeed controls (or boiler/reactor protection and controls) are longer-term phenomena with the timeframe of interest ranging from tens of seconds to several minutes.

Energy storage systems equipped with fast-acting grid interface power electronics offer an alternative to the traditional strategy of maintaining adequate spinning reserve margin to mitigate frequency contingencies. In response to such events, energy storage systems can supply "prompt" spinning reserve (PSR), i.e., rated power deployed within a few cycles for a sufficient period to enable other generation assets (e.g., Replacement Reserves) to be brought on line. The PSR approach avoids the capital and operating costs associated with continuously operating spinning reserve generation at part load and can be designed to provide regulation, voltage control and black start capability within the same facility. As the energy storage industry matures, it is likely that PSR will be considered within the energy market as an "ancillary service". As described in the following paragraph, the PSR concept is being demonstrated by the Golden Valley Electrical Association (GVEA) [Fairbanks, Alaska] as an alternative to increased spinning reserve margin to avoid future occurrences of the event that occurred on April 19, 1997 as illustrated in Figure 3-3.

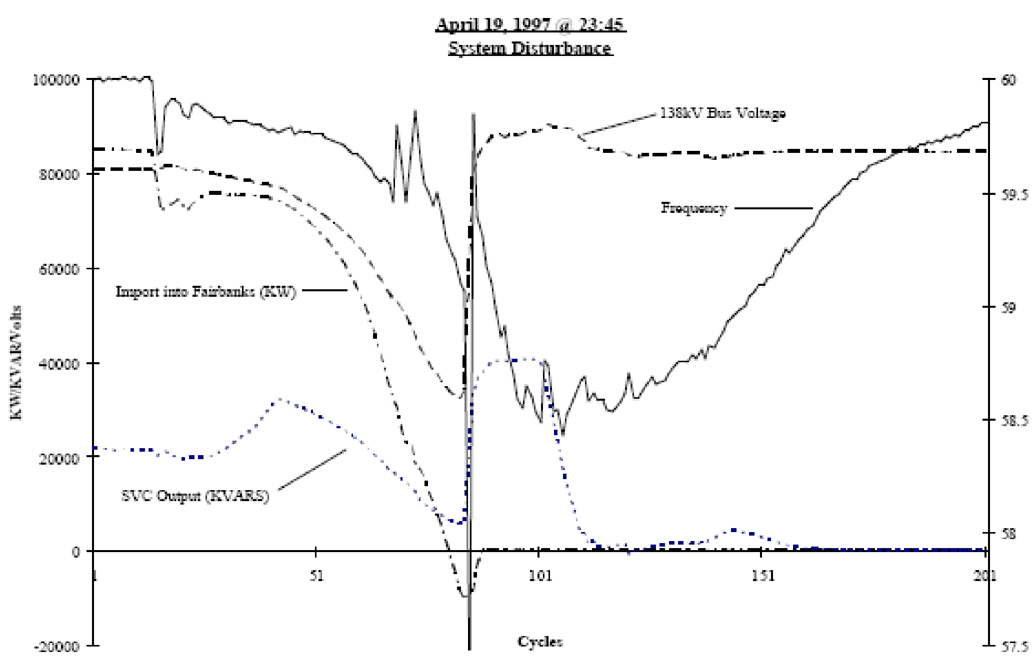


Figure 3-3
Disturbance on GVEA System Following Loss of 25MW$_{ac}$ Generation

The figure shows the response of a disturbance on the GVEA system that occurred following the loss of a 25 MW$_{ac}$ coal fired power plant in Healy (100 miles from Fairbanks). The chart was developed from a monitor at Goldhill substation located in Fairbanks. At the time of this system disturbance, the load in Fairbanks was being served by a combination of local generation (with no reserves) and a 60 MW$_{ac}$ import over the 138 kV Northern Intertie from Anchorage (400 miles away). Of the 60 MW_{ac} on the Intertie, 25 MW_{ac} were from Healy. Following the loss of the Healy plant, generation in Anchorage responded and overloaded the Intertie (due to excessive line losses). This resulted in voltage and frequency decay on the Fairbanks end of the Intertie, to which Static VAR Compensators (SVCs) at Goldhill and Healy responded until reaching their limits (33 MVAR @ Goldhill). Because VAR support was still inadequate, the voltage decayed to 0.43 PU at which time a relay opened the Intertie line breaker at Goldhill Substation. After the breaker opened, Fairbanks was in an islanded condition with insufficient generation. Frequency continued to decay until sufficient load was shed to stabilize the system [5]). To address such events, GVEA is introducing battery energy storage to deliver 40 MW_{ac} for 15 minutes full power discharge. This project is discussed in more detail in Chapter 7, Nickel Cadmium Batteries.

Voltage Stability

Theoretically, voltage stability is challenged by either a sudden increase in demand or decrease in generation; however, the latter is rare. Because of the fundamental relationships between load and voltage, maintaining adequate reactive power is critical to ensuring voltage stability. Since inductive line losses make it inefficient to supply a large amount of reactive power over long transmission lines, loads requiring high in-rush currents such as large motors must be supported locally. Voltage instability induced by major disturbances such as loss of generation or transmission assets is characterized by scenarios of system response such as load recovery or shedding actions, regulation control, etc. The following is a representative scenario [6]:

- High voltage transmission lines serving the critical area are heavily loaded and proximate generation capacity is temporarily reduced due to an unplanned outage. The adequacy of reactive power reserves is marginal or reserves are distant from the critical area.
- A transmission line is lost. The loading on the remaining lines, as well as the inductive reactive power, increases.
- The load voltage decreases, which momentarily decreases the load demand and the loads on high voltage transmission lines. However, the voltage control of the system quickly restores nearby generator terminal voltages by increasing excitation. The additional inductive reactive power at the transformers and transmission lines causes additional voltage drop at these components.
- After a few minutes (depending on time delay characteristics) on-load tap changers at distribution substation transformers restore distribution network voltages. Increased voltage also increases load demand which increases transmission line current, causing greater voltage drop in these lines.
- The increased demand for reactive power increases the reactive output of the generators. When a generator hits the reactive power limit, its terminal voltage decreases, and its share of reactive power demand is shifted to another generator farther away from the critical area. This will lead to cascading overloading of generators. Fewer generators are available for voltage control, and they are located yet farther from the critical area. The decreased voltage at the transmission system reduces the effectiveness of shunt capacitors by the square of

voltage. The system becomes prone to voltage instability, which may lead to voltage collapse.

Although the introduction of real power is theoretically unnecessary to establish voltage stability, analyses indicate that a small amount of real power significantly improves system performance by increasing the rate at which stability is restored and/or by decreasing the rating required of the power conditioning system, as well as the amount of reactive power needed.

Such relationships are illustrated in Figure 3-4 which shows the results of analyses of Wisconsin Power System's (WPS) Northern Loop where 115kV line outages caused low voltages and fast voltage collapse on the system. As indicated in the figure, the options evaluated are Static VAR Compensators (SVC), distributed STATCOMs and distributed STATCOMs with additional energy storage ([7], [8]). Note that the distributed STATCOM enabled voltage recovery to 0.8 V_{pu} well within the system criteria of less than 0.5 seconds after fault clearing, as required by certain high value customers on this system [9]. Alternatively, these criteria could have been met with smaller STATCOMs equipped with additional energy storage, as suggested by the figure.

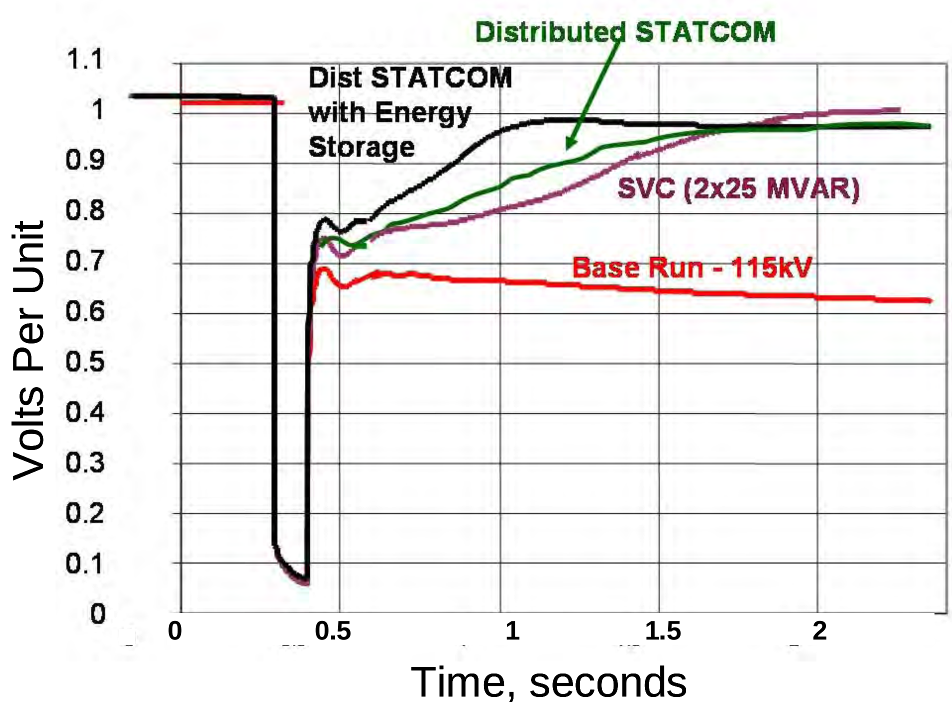


Figure 3-4
WPS Northern Loop Stability Analysis Showing Introduction of Energy Storage

As a result, WPS introduced six, 3 MW/6 MVAR SMES-based STATCOMs (American Superconductor "D-SMES") strategically located in their system having energy storage capacity nominally equal to 1 second full power discharge per unit.

A different strategy to address voltage instability contingencies was considered by the Independent System Operator of New England (ISO-NE) when the capacity of the 2000 MW_{ac} intertie with Hydro Quebec was limited to as low as 1200 MW_{ac} [10]. While this contingency could have been remedied with the installation of reactive power proximate to load centers in New York, no means existed for NE transmission utilities to recover the investment. However, an alternative solution consisted of introducing 15 minutes of energy storage accessible at full power within one second at the Sandy Pond substation, located near Boston. Such an energy storage installation serves as "prompt spinning reserve" (PSR) that would enable conventional spinning reserve generation to be brought on-line, thus increasing the available transmission capacity. This example illustrates the importance of location in identifying strategies to employ stored energy systems. Note, PSR is not the usual solution for voltage stability contingencies (see the previous section for a more complete discussion of PSR). Because the combination of circumstances at the Sandy Pond terminal is uncommon, this case is not considered to be a market application for the purposes of this Handbook. However, the issues that confronted NE-ISO illustrate the complexity of both grid phenomena and institutional constraints for which energy storage systems may offer attractive solutions.

Grid Operational Support

The electric power system has two unique characteristics: the need to maintain a near real-time balance between generation and load and the need to adjust generation (or load) to manage power flows through individual transmission facilities. These requirements are not new - vertically integrated utilities have been meeting them for a century as a normal part of conducting their business. With restructuring, however, the attendant "break up" of the vertically integrated system meant that the new market participants without specific market incentives to do so might no longer provide the services needed to meet these requirements. Ancillary services, as they are now called, are those functions performed by the equipment and people that generate, control, and transmit electricity in support of the basic services of generating capacity, energy supply, and power delivery. The Federal Energy Regulatory Commission (FERC), in its landmark restructuring Order 888, defined such services as those "necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." This statement recognizes the importance of ancillary services for both bulk-power reliability and to support commercial transactions. Order 888 listed six such ancillary services and provides a market mechanism for their supply in the interconnected transmission system.

Of the six FERC-defined ancillary services, storage technologies appear best suited to provide four: regulation, contingency reserves (spinning reserve, supplemental reserve, replacement reserve), voltage support, and possibly black start[1], though the latter two are judged not to offer attractive incentives in the current market (see additional discussion below). Brief descriptions

[1] The names and exact definitions applied to ancillary services differ from region to region, but technical requirements are essentially the same.

and typical duty cycles for these services are listed in Table 3-1, and more thorough characterizations are provided in the following sections.

Table 3-1
Definitions of Ancillary Services

Service	Service Description
Regulation	Power sources online, on automatic generation control, that can respond rapidly to system-operator requests for up and down movements; used to track the minute-to-minute fluctuations in system load and to correct for unintended fluctuations in generator output to comply with NERC's Control Performance Standard (CPS) 1 and 2 [11]. *Typical Duty Cycle:* System response within about 1 minute to continuously correct cyclic variations in grid frequency ranging from 2 to 20 cycles per hour.
Spinning Reserve	Power sources online, synchronized to the grid, that can increase output immediately in response to a major generator or transmission outage and can reach full output within 10 minutes to comply with NERC's Disturbance Control Standard (DCS) *Typical Duty Cycle:* Immediate response reaching full power within about 10 minutes and providing full power for up to 2 hours, called upon 5 to 20 times per year.
Supplemental Reserve	Same as spinning reserve, but need not respond immediately; therefore units can be offline but still must be capable of reaching full output within the required 10 minutes *Typical Duty Cycle:* Full power within about 10 minute to provide power for up to 2 hours, called upon 5 to 20 times per year.
Replacement Reserve	Same as supplemental reserve, but with a 30-minute response time, used to restore spinning and supplemental reserves to their pre-contingency status *Typical Duty Cycle:* Full power within about 30 minute to provide power for up to 2 hours, called upon 5 to 20 times per year.
Voltage Control	The injection or absorption of reactive power to maintain transmission-system voltages within required ranges *Typical Duty Cycle:* Immediate response to continuously provide reactive power at grid frequency (e.g., 60 Hz)
Black Start	The ability of a power source to go from a shutdown condition to an operating condition without assistance from the electrical grid and to then energize the grid to help other generating units start after a blackout occurs *Typical Duty Cycle:* Full power within minutes for durations up to a few hours, if applied directly for large generation plants. Deployment is rare, testing is conducted semiannually.

Overview of Ancillary Services Markets

Hourly markets for regulation and the contingency reserves (spinning, supplemental, and replacement) exist or are being formed in most ISO regions. This trend has emerged in response to a growing number of potential suppliers from which these services can be obtained. Consequently, commodity markets can be used to obtain the needed services from the lowest cost suppliers. Such markets can reveal value through prices and duty criteria, allowing a storage owner to determine which services can be profitably supplied. Commodity markets, as opposed to long-term contracts, are typically highly competitive because a resource's ability (and cost) to supply each of these services varies as its position in the hourly energy market varies. Thus, a storage owner would need to assess his position in the energy and ancillary services markets daily (or hourly) to determine if it is currently more profitable to arbitrage energy (buy low, sell high), sell regulation, sell spinning reserve, or perform a combination of functions.

The decision of which markets to participate in for a given hour will be based upon the current market prices for energy and ancillary services and upon the current capabilities of the storage facility. Once experience is gained with these markets, much of the decision process can be automated. The regulation and reserves markets are addressed in more detailed below as they are the primary candidate applications for energy storage.

Voltage control is the use of generating and transmission-system equipment to inject or absorb reactive power to maintain voltages on the transmission system within required ranges [12]. FERC decided that the costs of voltage control provided by transmission equipment (e.g., capacitors, tap-changing transformers, condensers, reactors, and static var compensators) should be incorporated into the basic transmission tariffs, and not valued separately. FERC decided that voltage control provided by generators should be a separate service. In general, generators can change their production and absorption of reactive power much more dynamically than can transmission related voltage control equipment. Rules for storage systems capable of reactive power support are yet to be addressed.

Because reactive power losses are much greater than real power losses in the T&D grid, voltage-control equipment must be dispersed throughout the system and located close to where the voltage support is needed. This also means that competitive markets are typically not practical for obtaining voltage control since there are too few potential suppliers at each location to compete. Instead, system operators install transmission equipment (tap changers, capacitors, reactors, static var compensators, etc.) to address voltage problems and/or they obtain voltage support from local generators. In some places, the generators are paid for this voltage support while in others they are simply required to supply voltage support capability as a condition of interconnecting with the power system.

Some storage technologies equipped with the appropriate four quadrant power conversion systems can be ideal suppliers of dynamic reactive power for voltage support. Their power electronic interfaces enable them to operate as a static var compensator, with no impact on the real energy being stored. In locations where voltage control is required, energy storage system owners may be compensated for such voltage control.

System black start capability is the ability of generating units to go from a shutdown condition to an operating condition without support from the grid. This capability, coordinated by the system operator, is essential during large-scale blackouts and islanding because such units can start themselves and then produce power that can be used to energize the grid and provide power to start other generating units. This service is, like voltage control, somewhat location dependent. System black start capability is typically obtained through long term contracts with black start capable generators [13].

Energy storage systems with the appropriate grid interface are able to provide system black start. Black start units need to have significant real and reactive power capabilities (typically 10 MVA or more) so that they can energize transmission lines, control voltage, control frequency, and supply the large and dynamic loads at the next-start generators. Black start capability can be provided with energy storage systems equipped with sufficient energy for several hours of power or, depending on the proximity of generators, with sufficient energy to deploy generators from a cold state, e.g., 15 minutes to one hour for gas turbines.

Regulation

Because electricity is a real-time product, control-area operators must continuously adjust generation to meet load. Load following (which, in competitive spot markets is provided by the intra-hour workings of the real-time energy market) and regulation are the two services required to perform this function [14].

Figure 3-5 shows the morning ramp-up broken into base energy, load following and regulation. Starting at a base energy of 3566 MW_{ac} the smooth load following ramp is shown rising to 4035 MW_{ac}. Regulation is the rapid fluctuations in load around the underlying trend shown here on an expanded scale to the right with a ±55 MW_{ac} range. Combined, the three elements serve a load that ranges from 3539 to 4079 MW_{ac} during these three hours.

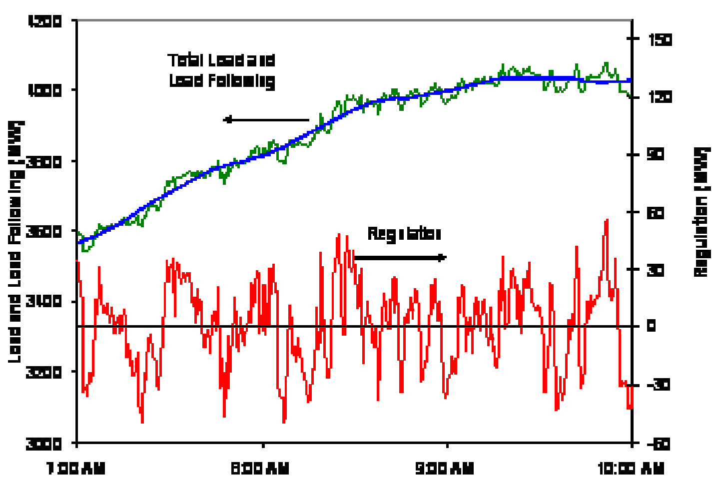


Figure 3-5
Load Following and Regulation Separate From Total Load

Load following and regulation ensure that, under normal operating conditions, a control area is able to balance generation and load. Regulation is the use of on-line generation (or storage) that is equipped with automatic generation control (AGC) and that can change output quickly (at the rate of a megawatt per minute) to track the moment-to-moment fluctuations in customer loads and to correct for the unintended fluctuations in generation. In so doing, regulation helps to maintain interconnection frequency, manage differences between actual and scheduled power flows between control areas, and match generation to load within the control area. Load following is the use of on-line generation (or storage) equipment to track the intra- and inter-hour changes in customer loads. Regulation and load following characteristics are summarized in Table 3-2.

Table 3-2
Regulation and Load Following Characteristics

	Regulation	Load Following (LF)
Patterns	Random and uncorrelated	Highly correlated
Control	Requires AGC	Can be manual
Maximum swing	Small	10-20 times greater
Ramp rate (MW/min)	5-10 times more than LF	Slow
Sign changes per unit time	20-50 times more than LF	Few

Control area operators do not need to specifically procure load following, since it is within the capability of generators and routinely obtained from the short-term energy market as generators respond to real-time energy prices. Regulation, however, requires faster response than can be obtained from units responding to market signals alone. Instead, generators (and potentially storage) offer capacity that can be controlled by the system operator’s AGC system to balance the power system.

Control areas are not able, and not required, to perfectly match generation and load. NERC has established the Control Performance Standard (CPS) in two categories to define the amount of permissible imbalance for reliability purposes, CPS1 and CPS2. CPS1 measures the relationship between the control area's area control error (ACE)[2] and the interconnection frequency for a 1-minute period. CPS1 values can be either "good" or "bad." When frequency is above its reference value, under-generation will lower the frequency and correct the CPS1 value. Over-generation at such times, however, would further increase frequency and degrade the CPS1 value. CPS1, although recorded every minute, is evaluated and reported on an annual basis. NERC sets minimum CPS1 requirements that each control area must exceed each year.

CPS2, a monthly performance standard, sets control-area-specific limits on the maximum average ACE for every 10-minute period. Control areas are permitted to exceed the CPS2 limit

[2] Area Control Error is the difference between scheduled and actual net interchange with a bias included to help maintain scheduled system frequency.

no more than 10% of the time. This 90% requirement means that a control area can have no more than 14.4 CPS2 violations per day, on average, during any month.

Energy storage installations capable of a high number of cycles should provide excellent regulation because this function nets a zero change in stored energy., i.e., it requires continuous cycling. The quick response and precise control offered by storage is also superior to the control capabilities of many conventional generators.

Contingency Reserves

Contingency reserves (spinning, supplemental, and replacement reserves) restore the generation/load balance after the sudden unexpected loss of a major generator or transmission line. Power system frequency drops suddenly when generation trips and there is no time for markets to react. In the case illustrated in Figure 3-6, frequency sensitive generator governors responded immediately to stop the frequency drop. Spinning and supplemental reserves successfully returned frequency to 60 Hz within 10 minutes[3]. Control areas (or reserve sharing groups) typically keep enough 10-minute contingency reserves (spinning and supplemental) available to compensate for the worst credible contingency. At least half of these are often required to be spinning. Sufficient replacement reserves are typically required to cover 50% of the second worst contingency. The largest contingencies are typically the loss of the largest generator or the largest importing transmission facility. In Texas, the simultaneous loss of a two unit nuclear plant is credible (as shown by the event recorded in Figure 3-6), so the Electric Reliability Council of Texas requires over 2600 MW_{ac} of contingency reserves. Major contingency events typically occur a few times a month.

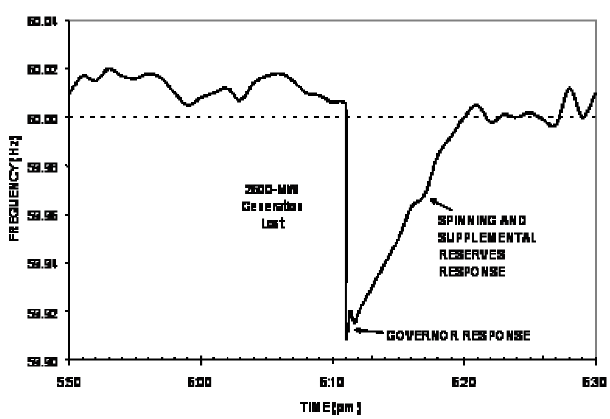


Figure 3-6
Governor Response and Contingency Reserves Restore Generation/Load Balance

[3] NERC requires control areas to restore the generation/load balance within 15 minutes. Reserve service definitions require full reserve response within 10 minutes. The additional 5 minutes is provided for the system operator to assess the situation and respond.

A series of coordinated contingency reserves are maintained to deal with the sudden, unexpected loss of generation or transmission. Frequency (governor) response, spinning, supplemental, and replacement reserves deploy sequentially, as shown in Figure 3-7. Separate reserve services were defined because these services usually came from different resources in the past. The fastest services (frequency response and spinning reserves) had to come from generators that were on-line, spinning, and loaded at less than full output. Supplemental reserves had to be fully available within 10 minutes but could come from fast-start generators. Replacement reserves could come from slower resources as long as they could be fully available within 30 minutes. Reserves were typically required to be capable of deploying for two hours, after which it was expected that the emergency would have been addressed and more normal conditions restored. These definitions are still in place (NERC no longer requires spinning reserve to come from generation but most Regional Reliability Councils do), though the reasoning is now outdated in light of the viable storage technologies now available.

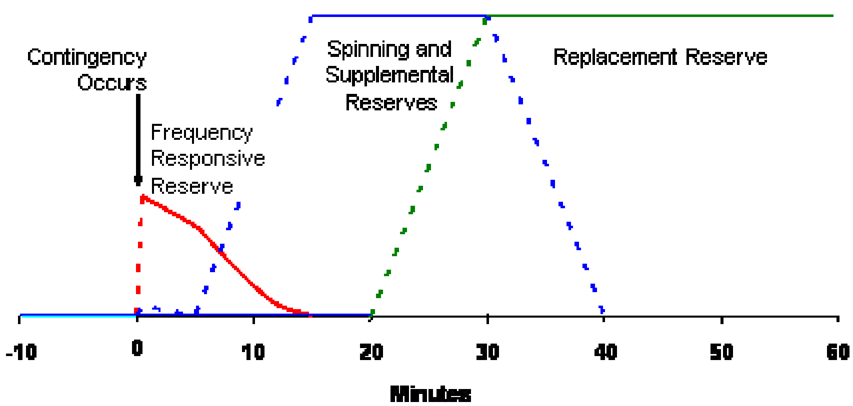


Figure 3-7
Coordinated Reserve Response to Sudden Loss of Generation or Transmission

Historic reserve requirements were prescriptive. For example, NERC guidelines suggested that spinning reserve be restricted to generators that were on-line, less than fully loaded, and capable of providing their full reserve within 10 minutes. This requirement, coupled with the provision that all generators be equipped with frequency responsive governors, assured policy makers that adequate reserves would be available to stabilize frequency if a contingency were to occur.

Restructuring and advances in generation, storage, and responsive load technologies are necessitating rule changes. Prescriptive NERC guidelines are being replaced with mandatory functional standards. Through their Disturbance Control Standard (DCS), NERC requires control areas to restore the generation/load balance within 15 minutes of a major contingency. Regional reliability councils further require that specific amounts of each contingency reserve be maintained. But the contingency reserve definitions are becoming technology neutral in that they now require a defined response within a given timeframe, rather than specifying reserve capacity (margin) from specific technologies.

A frequency responsive reserve standard has not yet been established. Instead, the spinning reserve and supplemental reserve standards are identical except that spinning reserve resources must begin responding "immediately" and reach full output within 10 minutes. Storage technologies are typically "prompt" – a distinction and value that is not currently recognized by the market rules. Stakeholders need to participate in rulemaking so that energy storage technologies are fully valued.

The New York ISO (NYISO) does not restrict use of the 10-minute reserves to DCS events. The entire NPCC region experiences about 72 DCS events per year, but the NYISO deployed 10 minute reserves 239 times in 2002, as shown in Figure 3-8 [15]. Deployment times ranged from 24 seconds to 70 minutes but averaged less than 11 minutes. The average time interval between deployments was 36 hours, but intervals ranged from 24 seconds to 350 hours.

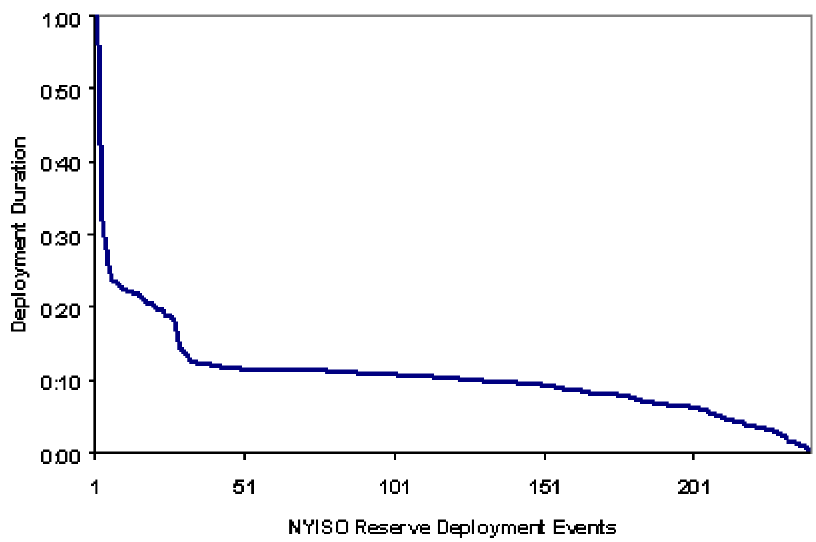


Figure 3-8
Most Reserve Deployments in New York In 2002 Were Shorter Than 12 Minutes

It should be noted that the foregoing spinning reserve definitions, which were written exclusively with conventional generators in mind, can drive unintended behavior from energy storage system owners. The reserve requirements typically require response to start immediately, i.e., to be fully available within 10 minutes, and to be sustained for 30 minutes to two hours (depending on the NERC Region). They assume that a generator is supplying the reserve and that it will begin ramping immediately to provide all it can as fast as it can - just what the system operator wants in an emergency.

A storage plant, with superior prompt response capabilities, may deliberately limit its response in order to maximize its payment under the established service rules. A storage plant might be capable of providing full output essentially instantly, a great improvement over conventional generation. But if that storage plant has limited energy available, the operator will likely decide to delay response for the full 10 minutes allowed to reach full output. This would allow the storage plant to spread the limited energy over the required response duration, maximizing the capacity for which it gets paid. For example, a 20 MW_{ac} battery plant with 20 MWh of available energy storage could only bid 10 MW_{ac} into a spinning reserve market that required 2 hours of response. The owner could increase the bid amount to 10.9 MW_{ac} if they delayed response by the allowed 10 minutes.

But what would the system operator really want from the battery? Twenty MWs immediately and delivered for up to 60 minutes. That is much more valuable than what any conventional generator could provide. That large, fast response buys the system operator up to an hour to find other resources. Clearly, the reserve definitions and market rules need refinements to elicit the best reliability response from emerging energy storage systems.

Summary

Conceptually, storage is ideal for supplying several ancillary services. Regulation is, by its nature, a frequent cycling and zero-energy-storage/balancing service. Contingency reserves require the injection of real power into the transmission system but actual deployment is relatively infrequent. Payment for the services is primarily for the available capacity ready to deploy.

Supplying voltage control and reactive power likely does not interfere with the storage project's primary real power mission. It is likely to design the project's power electronics such that they can supply dynamic voltage support while real-power functions are being performed since the added cost impact is modest and the potential for being a required criterion is real.

Black start is more selective. To be useful, the storage project has to be sufficiently large and charged when a blackout occurs. This requires reserving capacity that is then not available for typically other more lucrative applications. However, a sufficiently large storage project could supplement whatever residual charge was available with charging from low-power emergency generation and provide a useful black start resource. The dynamic VAR capability, along with fast real power control could be an ideal black start resource.

Regulation is an ideal service for storage, if the storage device is not limited by cycle life. Regulation is the highest priced ancillary service; 4 to 6 times the price of spinning reserve and the price is high around the clock. A storage project can supply regulation any time it is idle from its primary function or can be supplied coincidentally with its primary function. The superior control capabilities, when compared with conventional generation, provide an additional benefit. A requirement is that the storage facility must provide appropriate head-room and foot-room to be able to both inject and absorb energy. Storage devices with limited cycle life may be better suited to supplying contingency reserves. Storage systems are typically better suited to providing the highest value function, spinning reserve, which requires fast response but limited deployment time. Unlike conventional generators, energy storage technologies can easily provide fast response; however, they are limited in the duration of their response. Frequency responsive reserves will likely be an even better match to storage's capabilities. Its expected higher value will make this choice more profitable.

For the purposes of this Handbook, regulation and spinning reserves have been selected as the reference application candidates for the respective energy storage systems. Representative duty cycles are provided in this chapter, and the benefit parameters are addressed in Chapter 4.

Distribution Power Quality and Reliability

Distribution level electrical power quality and reliability in the U.S. is generally good to excellent, but with significant variability related to the local grid design, e.g. radial versus loop lines, exposed overhead versus protected underground lines, plus the local exposure conditions related to weather, animal life, and foliage. However, even in the best of conditions, the overall reliability of undisturbed service from the grid is in the range four 9s, i.e. 99.99%. Note, a disturbance herein includes any power quality phenomenon that negatively impacts the customer as well as the extreme case of an outage. When such disturbances occur, the utility's customers can experience a range of consequences: disrupted operations, damaged equipment and product, loss of information and/or complete shutdown for recovery that can extend much longer than the power disturbance itself.

These problems are exacerbated with the ever advancing digital economy and the proliferation of electronic equipment and microprocessor-based controls that are sensitive to power disturbances. In addition, there are increasing public service, safety and security demands on electric power supply. To date, these overall demands have been primarily addressed with some combination of customer owned power quality and reliability systems and/or enhanced utility supply service, e.g. multiple feeds. However, with the restructuring of the utility industry, the distribution utility's incentive for such enhancements has been reduced, if not lost altogether.

Concurrently, a growing portfolio of "distributed energy storage and/or generation resources" are evolving that are well suited for distributed power quality and reliability support as well as other customer and/or grid support functions. This section addresses the distribution level power quality and reliability issues that are opportunities for energy storage based systems. Later, combined grid support applications are addressed that, taken together, offer increased incentive for the distribution utility's deployment of such systems.

The specific nature of these distribution-level disturbances has been studied in great detail, including a landmark study by EPRI and participating utilities called Distribution Power Quality or DPQ. The first study, DPQ I, was completed in 1996 and DPQ II was completed in 1998 [16]. An important outcome of this study, particularly regarding the mitigating role of energy storage, was the realization that the vast majority of grid related power quality events are voltage sags and, to a much lesser extent interruptions, with both being opportunities for energy storage based solutions.

Figure 3-9 summarizes the results of DPQ II, which supports previous results in DPQ I, and shows the distribution of the sags and momentary interruptions as a function of their duration up to a few seconds and their percent of voltage sag. Note that the majority of the voltage sag disturbances occur less than 2 seconds and less than 50% sag.

As defined by IEEE Standard.1159-1995, a voltage <u>sag</u> is a short-duration decrease of the RMS voltage, lasting from 0.5 cycles to two minutes in duration. These events are caused by faults on the power system or by events such as starting a relatively large motor or other inductive load. A voltage <u>interruption</u>, on the other hand, is the complete loss of electric voltage. Interruptions can be for a short or long duration. Disconnection of electricity causes an interruption - usually by the opening of a circuit breaker, line recloser, or fuse. For example, if a tree or animal comes into contact with an overhead line or high voltage bus, or if an insulator flashes over due to a lightning strike, some type of circuit interrupter (breaker, fuse, recloser, etc.) will attempt to isolate the faulted line from the rest of the system (often referred to as "clearing" the fault (short circuit). A finite time is required, however, to "clear" the fault, and during that time both customers on the faulted line as well as customers on parallel feeders (that is, feeders that are supplied from the same bus as the faulted feeder) will experience a voltage sag. After the faulted line is isolated, the customers who receive their power from that line will experience an interruption, while customers on parallel feeders will experience normal voltage or, perhaps a momentary voltage "swell" (over voltage) caused by the loss of load served by the faulted line. In this scenario, the cause of the interruption is the same as the cause of voltage sags with the customer's experience dependent on location relative to the faulted line.

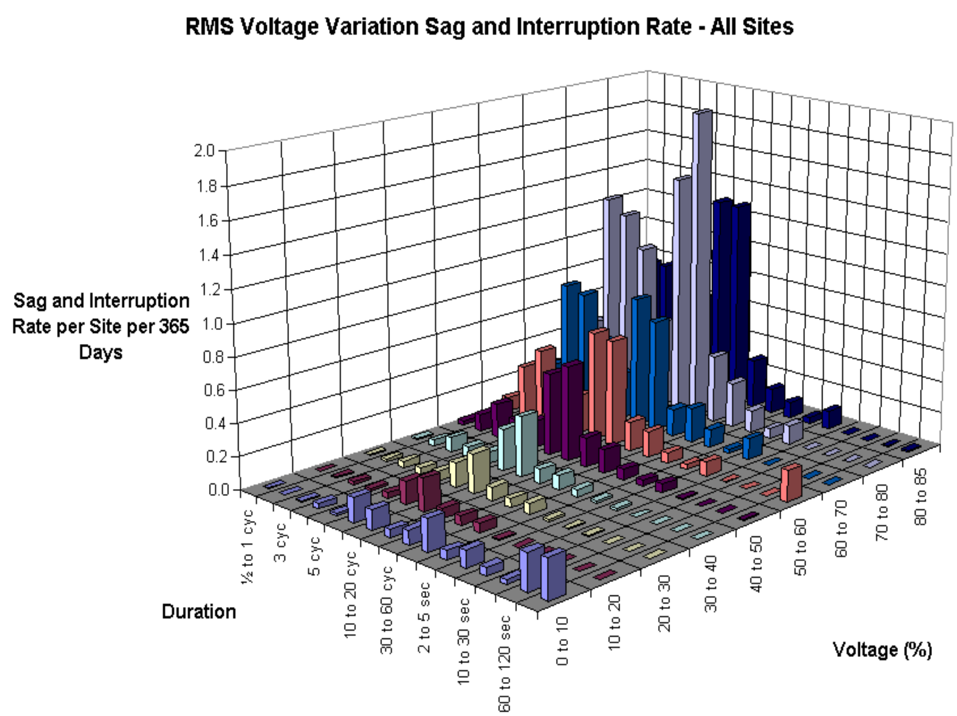


Figure 3-9
Summary of DPQ Results for Sags and Momentary Interruptions [16]

Note that two different time intervals are to be distinguished for these operations. The first is the time to "clear" the fault (i.e., the time it takes to initially sense the fault and then open the recloser). During this time, the fault is active and is producing voltage sags on both the affected feeder and all parallel feeders. The second is the interval of time between the completion of the opening interval and the initiation of an automatic reclosing. During this time, customers on the faulted feeder experience an interruption (at least those who are "downstream" from the recloser) and those "upstream" of the recloser as well as all those on parallel feeders experience normal voltage or perhaps a voltage swell, as explained above.

Customers located on the faulted feeder will experience one or more interruptions (and those on parallel feeders may experience more than one sag), depending on the type of fault and the reclosing practices of the utility. Reclosing practices vary from utility to utility and, perhaps, from circuit to circuit.[4] For a temporary fault, one or two reclosing operations may be required before normal power is restored. For a permanent fault, a number of reclosing operations (usually no more than three) will occur before the breaker "locks out" because of the permanent fault condition. In this case, the customers on the faulted line will experience a sustained interruption. Note that the interruptions associated with successive operations of the recloser are typically of varying duration depending on relay characteristics and utility practice. This provides multiple opportunities for removal of the conditions causing the fault. The multiple operations also give sectionalizers the opportunity to operate. These devices typically open during the dead time (recloser open) after counting a certain number of consecutive incidents of fault current within a short time period. The number of fault current incidents is typically two, although it could be one if the sectionalizer is at the head of an underground cable where all faults are assumed to be permanent.

For residential feeders, some utilities are experimenting with shorter intervals (0.3 to 0.5 seconds) for the first recloser interval to solve problems that residential customers have with momentary interruptions. (Residential electronic equipment such as clock radios, VCRs, microwaves, and televisions can often ride through 0.5 second interruptions, but cannot ride through much longer duration interruptions.) There is a practical minimum, however, because at medium voltage levels it usually takes at least 10 to 12 cycles of dead time to ensure that the ionized gases from faults are dispersed.

Customers located on parallel feeders will experience a voltage sag for the duration that the fault remains on the line. On medium voltage systems, nearly all faults are cleared within one second and can be cleared in as short as three cycles, depending on the fault current magnitude and the relay settings. This means that customers on parallel feeders will experience at least one voltage sag lasting from three cycles to approximately one second and possibly additional voltage sags if reclosing operations are required. Voltage sags are typically less severe than interruptions and the duration of interest is only the period of time that the fault is on the line.

If there are more than two feeders supplied from a common distribution bus, more customers will experience voltage sags than actual interruptions because a fault on any one feeder will cause voltage sags on all the other feeders.

[4] Most utilities employ automatic reclosers to minimize the use of fuses that require field maintenance for the restoration of power. Reclosers, unlike fuses, also increase the probability of quicker power restoration (fuses do not provide a repeated application of high voltage to help remove the condition causing the fault).

Customers fed directly from the high-voltage system (that is, transmission-fed or large industrial customers) usually have more than one line supplying the facility and actual interruptions should be very infrequent for these customers. However, these customers will experience voltage sags during fault conditions over a wide range of the transmission system. Voltage sags caused by high-voltage-system faults generally have more consistent characteristics. The faults that originate in the medium- and low-voltage systems tend to have more variation in depth and duration.

Longer-term outages (minutes to hours) are rare and typically caused by equipment failures, accidents, weather or natural disasters, or instability induced system collapses. Albeit rare, the impact is widespread and in many cases warrants protective backup systems.

Energy storage for such short and long-term power quality related applications at or within the end-user site is an established and robust business, e.g. the ubiquitous lead acid battery based UPS system. The most common UPS application is for computer centers. These protect against voltage sags as well as outages for up to 30 minutes and, if the outages are not mitigated, provide power for an orderly shutdown to protect electronic records. Another major energy storage based power quality and reliability application and market is in the telecom industry, which has a regulatory-based legacy of applying hours of backup batteries throughout their supply networks. Likewise, T&D utilities deploy hours of battery systems at substations for backup power for breaker operations, controls and communication. In addition, there is an established robust business for backup gensets equipped with sufficient fuel for hours of operation depending on their proximity to refueling supplies. Many public health and safety facilities, e.g., hospitals, are required to have standby gensets. For central telecom offices, multiple gensets are often included as a means of charging the large battery banks - an indication of the premium for high reliability service and regulatory compliance. Alternatively, short-duration energy storage may be adapted to mitigate brief power disturbances plus provide a bridge to startup and synchronize standby gensets for long-term protection.

For large facilities that require site-wide protection, several such power quality systems have evolved that are also suited for deployment at the utility substations, whether dedicated to a single customer or multiple customers in a premium power park arrangement. Examples are lead acid battery and flywheel based short-term UPS systems with options for bridging to genset systems.

However, the traditional T&D utility solution for enhanced power quality and reliability has been multiple feeds into the service area that draw on, to the extent possible, independent sources of power generation and/or transmission feeds. The static transfer between independent feeds has been the utilities' primary power quality and reliability solution for high value customer facilities.

For the purposes of this Handbook, two representative and bounding type applications have been selected. The first covers the short duration voltage sag disturbance. Although not yet adopted by any system vendor, 2 seconds of full power duration has been selected for the baseline evaluations because it captures the large majority of relevant disturbances, plus it is allows the meaningful comparison of the full range of short-term based energy storage technologies. The second application covers the long duration outage. Four full power hours has been selected which aligns with the utilities' interruptible service duration and rolling blackout precedents. Further, it is sufficient time for commercial and industrial customers to ride-through the vast majority of outages or accomplish an orderly shutdown and evacuation of the premises without reliance on a genset. Such genset reliance, particularly for new installations, is increasingly problematic for metropolitan service areas due to emission, noise and vibration based permitting issues. Further, four hours of backup is compatible with the backup duration trend in the telecom industry.

Daily Load Shifting

For the purposes of this Handbook, load-shifting pertains to the use of energy stored proximate to the point of use during periods of low demand to reduce the need for remotely generated power imported over transmission and distribution assets during periods of high demand. In this manner, a portion of the customer load is shifted from periods of high to periods of low demand (e.g., from mid-afternoon to late-night hours). As a result, utility assets are more uniformly loaded throughout the cycle, and the need to upgrade or expand the system can be avoided or deferred. In addition, such load shifting can accommodate the displacement of the more expensive peak energy costs (or prices) with the less expensive off-peak energy costs (or prices). Load-shifting may be implemented as part of an overall system (generation, transmission and distribution asset) optimization strategy, and its value is dependent on marginal, locational, and temporal factors:

- Marginal, in that power delivered to serve the load increment in excess of rated grid capacity is valued at the marginal cost of capacity expansion, e.g., at the incremental cost of adding generation, which may be under utilized until system build-out.
- Locational, in that distance, terrain and demographics between generation and load centers all contribute to the marginal cost of power, e.g., infrastructure disturbance in urban areas may be costly, environmental intrusion in open spaces may entail lengthy approval processes, etc.
- Temporal, in that the need for a marginal increment of power is typically a fraction of total time that coincides with daily and seasonal periods of peak demand, and must occur at cyclic periods of low demand to allow charging for load shifting to have value.

The appropriate amount of such load shifting with energy storage will depend on the load profiles; the alternative costs of adding or expanding demand side management (DSM) options; the value of deferring or avoiding the alternative infrastructure upgrades; the difference in peak versus off-peak costs (or prices); plus the storage system's costs and efficiency. Parameters for the alternative costs and hence the benefit bases for energy storage are addressed in Chapter 4.

Society's basic diurnal consumption of power results in a higher day-time load (peak) versus the night-time load (off-peak). Of course, three-shift industrial loads, night lighting loads, etc. serve to offset this difference. Profiles of the utility's daily loads at any given substation vary due to many factors, including:

- The Monday through Friday workdays typically have a higher peak load and peak/off-peak difference versus the weekend days and holidays.
- Likewise, the seasonal HVAC load factors can be distinctively significant, depending on climate extremes, which can result in a higher summer peak, winter peak or both.
- Further, hourly variations of the peak load can be significant during the transition between on peak and off-peak, as well as during seasonal daily temperature change extremes.
- Otherwise, the mix of load (any combination of residential, commercial, industrial and transportation) for any given substation may serve to flatten or exaggerate the peak versus off-peak profile. Further, this mix can change over time, e.g. rezoning of neighborhoods, as well as at the convenience of the utility to balance loads between proximate substations.

Altogether, utility substation load profiles are both diverse and dynamic. Hence, desired features for energy storage systems for such application include modularity and relocatability.

For the purposes of this Handbook, two representative and bounding profiles have been selected. The first assumes a short 3 hour mid-day peak for a seasonal 60 days per year (or 12 weeks and 5 work-days per week), hence relatively low energy discharge and low discharge-charge cycle duty. The second assumes a long 10 hour day-long peak for a year-round 250 days per year (or 50 weeks and 5 work-days per week), hence relatively high energy discharge and high discharge-charge cycle duty. Circumstances for either are readily deduced from the discussion above, with the first being more typical of most substation profiles.

All cost and value components being the same, the second profile is the stronger candidate for an energy storage application. However, depending on the magnitudes of such components, it may or may not be attractive as a stand-alone application. In combination with other energy storage applications, either or both are more likely to be well suited for one or more (and probably different) energy storage technologies, as will be addressed in this Handbook.

Summary of Single Function Applications and Top-Level Energy Storage System Requirements

The preceding four sections have described the single function T&D applications selected for inclusion in this Handbook in terms of the associated grid phenomena to be mitigated and/or the power market opportunity. These nine applications are representative of realizable opportunities for energy storage systems in the near-term. This section identifies the top-level requirements that serve as the bases for configuring the integrated energy storage systems for the respective technologies that are described and assessed in this Handbook. Table 3-3 lists the key requirements associated with each single function application. Note that the table shows the range of parameters that may be encountered for a particular application, as well as the reference values shown in parentheses that have been selected for assessment in this Handbook. These requirements also provide the bases for combined function applications described in the section titled, Energy Storage Technology Suitability for T&D Applications.

As indicated in Table 3-3, the reference power and voltage selected for all applications (with the exception of PSB (Regenesys) and large Compressed Air Energy Storage (CAES)) are 10 MW_{ac} and 13.8 kV, respectively. These values are used in arriving at the unit configurations and costs of the electronic power conversion and energy storage systems addressed herein. The choice of unit size was made in light of the primary objective of this Handbook to improve insight to emerging energy storage technologies in T&D applications, as well as in recognition of the stage of development of those technologies and the likely size range of utility projects within the next few years. Recent and relevant energy storage projects undertaken by utilities are listed in Table 3-4, where PbA and NiCad technologies are mature and NAS and PSB are emerging. The choice of unit size is acknowledged to compromise the requirements for some applications (e.g., the preferred size of GAS installations might be several hundred megawatts at some sites) as well as the requirements for the target markets of some technologies. However, these goals are deemed secondary to the need for improved familiarization and insight to options for additional early utility-scale energy storage projects. The use of standard unit size (where multiple parallel units can be configured for larger facilities) facilitates the analyses and presentation of results shown herein. With regard to CAES, unit sizes of both 10 and 135 MW_{ac} are assessed, where the former is oriented to above grade installations employing fabricated pressure retention devices (pipes, pressure vessels, etc.) and the latter to subterranean geologic features. CAES power conversion is accomplished by mechanical rather than electronic means; hence, the normalization of PCS is not addressed for CAES.

Table 3-3
Top-Level Energy Storage System Requirements for Single Function T&D Applications

Applications / Parameters	Grid Stabilization (GS)			Grid Operational Support (GOS)		Distribution Power Quality (PQ)		Load-Shifting (LS)	
	Angular Stability (GAS) **A**	Voltage Stability (GVS) **B**	Frequency Excursion Suppression (GFS) **C**	Regulation Control (RC) **D**	Conventional Spinning Reserve (SR) **E**	Short Duration PQ (SPQ) **F**	Long Duration PQ (LPQ) **G**	Short Duration LS (LS3) **H**	Long Duration LS (LS10) **I**
ES System Unit Power, MW	10 to 500 (10)	10 to 500 (10)	10 to 500 (10)	2 to 200 (10)	2 to 200 (10)	1 to 50 (10)	1 to 50 (10)	1 to 200 (10)	1 to 200 (10)
ES System AC Voltage, kV	4.2 to 750 (13.8)	4.2 to 750 (13.8)	4.2 to 750 (13.8)	4.2 to 115 (13.8)	4.2 to 115 (13.8)	4.2 to 34.5 (13.8)	4.2 to 34.5 (13.8)	4.2 to 115 (13.8)	4.2 to 115 (13.8)
Equivalent Full Power Discharge Duration	few seconds (1 sec)	few seconds (1 sec)	10 to 30 min (15 min)	3 to 30 min (7.5 min)	2 hr max (2 hr)	seconds (2 sec)	hours (4 hrs)	1 to 4 hrs (3)	5 to 12 hrs (10)
Energy Discharged Per Event	10 MJ to 1 GJ (10 MJ)	5 MJ to 30 GJ (10 MJ)	0.2 to 25 MWh (2.5 MWh)	0.1 to 25 MWh (2.5 MWh)	2 to 100 MWh (20 MWh)	2 MJ to 3 GJ (50 MJ)	1 to 400 MWh (40 MWh)	1 to 200 MWh (30 MWh)	5 to 600 MWh (100 MWh)
Energy Discharge Duty Cycle	10 events/yr 1 event/d 20 cyc/event	10 events/yr 1 event/d	10 events/yr 1 event/d	Contin-uous Market (Ref 2 cycles/hr)	10 events/yr 1 event/d	100 events/yr 5 events/d 1 event/hr	1 event/yr	60 events/yr 1 event/d	250 events/yr 1 event/d
System Response Time	< 20 msec	< 20 msec	< 20 msec	<10 min	<10 min	< 20 msec	< 20 msec	<10 min	<10 min
Basis for Economic Benefits	Capitalized Costs and Benefits of Alternative System			Market Rates		Capitalized Costs and Benefits of Alternative System		Reduced T Demand Charge, plus Δ Energy Savings plus Capitalized Costs and Benefits of Alternative System	

Table 3-4
Early Energy Storage Project Precedents for 10 MW_{ac} Range Unit Size

Utility	Energy Storage Technology (Acronyms Below)	Unit PCS MW_{ac} - Facility MW_{ac} - Facility MWh_{ac}	Initial Startup (Incremental Rise to Facility Power)
Puerto Rico Power Authority (PREPA)	PbA Batteries	10 - 20 – 6.3	Spring 1994
Tokyo Electric Power Company (TEPCO)	NAS Batteries	2 – 6 -48	Spring 1997
Golden Valley Electric Association (GVEA)	NiCad Batteries	27* – 27 -6.75	Fall 2003
National Power (NPUK)	PSB Flow Battery	12 -12 -100	Scheduled 1st Qtr 2004
Tennessee Valley Authority (TVA)			Follows NPUK by 6 to 12 mo
Acronyms:			
PbA Lead Acid batteries			
NAS Sodium-Sulfur batteries			
NiCad Nickel Cadmium batteries * PCS rated at 46 MW_{ac} max			
PSB Sodium Polysulfide/Sodium Bromide flow battery (also known as Regenesys)			

Bases for economic evaluation are identified in this section, and the methodology for deriving benefits and costs is presented in Chapter 4. Key duty cycle requirements for each application listed in Table 3-3 are discussed in the following paragraphs:

Application A: Grid Angular Stability (GAS) – These applications require that power oscillations be mitigated by injecting and/or absorbing real power at frequencies of 0.5 to 1 Hz, and may be encountered in systems with long transmission lines at voltages up to 750 kV (typical of the Western or Northeast U.S.). The energy storage system must detect the disturbance and respond within 20 milliseconds by injecting and/or absorbing oscillatory power opposing the disturbance for up to 20 cycles. Ten such events may occur per year, but more than one event per day is considered unlikely. Commercial installations are expected to range in size from 10 to 500 MW_{ac}.

The reference duty cycle for analysis is hot standby for infrequent events characterized by an event of 20 oscillatory cycles, cumulatively equivalent to a full power discharge (FPD) of 1 second duration and subsequent charge cycle; 1 event per day; 10 events per year. This application is valued at the cost of alternative solutions.

Application B: Grid Voltage Stability (GVS) – These applications require that degraded voltage be mitigated by additional reactive power, plus injection of real power for durations up to

2 seconds, and may be encountered in systems with transmission congestion and high inductive loads (typical of the Eastern US). The energy storage system must continuously supply reactive power, plus detect the disturbance and respond within 20 milliseconds by injecting real power for up to one second. Ten such events may occur per year, but more than one event per day is considered unlikely. Commercial installations are expected to range in size from 10 to 500 MW_{ac} at voltages up to 750 kV.

The reference duty cycle for analysis is hot standby for infrequent events characterized by 1 second FPD, 1 event per day, 10 events per year. This application is valued at the cost of alternative solutions.

Application C: Grid Frequency Excursion Suppression (GFS) – These applications require "prompt" spinning reserve (or load) for mitigating imbalances between load and generation and arise in circumstances (e.g., inadequate spinning reserve) best mitigated by mobilizing alternate generation to sustain grid stability. Such applications may be encountered in electrically isolated systems (e.g., Golden Valley Electric Association, Alaska) or at power import terminals where contingencies limit full capacity. The energy storage system must detect the disturbance and respond within 20 milliseconds by injecting real power for up to 30 minutes. Commercial installations are expected to range in size from 10 to 500 MW_{ac} in transmission systems at voltages up to 750 kV.

The reference duty cycle for analysis is hot standby for infrequent events characterized by 15-minute FPD, 1 event per day, 10 events per year. This application is valued at the cost of alternative solutions.

Application D: Regulation Control (RC) – These applications provide system frequency regulation in concert with load following in response to opportunities in the power market. Such applications are widespread and routinely filled by generating plants. The energy storage system must be deployable by automatic generation control with 10 minutes notice and provide continuous response to cyclic load changes ranging from 1 to 20 cycles per hour. A typical duty cycle profile is shown in Figure 3-5. Commercial installations are expected to range in size from 2 to 200 MWac in systems at voltages up to 115 kV.

The reference duty cycle for analysis is characterized by continuous cycles equivalent to 7.5-minute FPD and charge cycle (triangular waveform), 2 cycles per hour deployed with 10 minutes advance notice. This application is valued at market rates.

Application E: Spinning Reserve (SR) – These applications provide reserve power for at least 2 hours with 10 minutes notice in response to opportunities in the power market. Such applications are widespread and routinely filled by generating plants. The energy storage system must be deployable by automatic generation control with 10 minutes notice and provide power for up to 2 hours when deployed. Commercial installations are expected to range in size from 2 to 200 MW_{ac} in systems at voltages up to 115 kV.

The reference duty cycle for analysis is standby for infrequent events characterized by 2-hour FPD, 1 event per day, 10 events per year. This application is valued at market rates.

Application F: Short Duration Power Quality (SPQ) – These applications mitigate voltage sags (e.g., recloser events) in distribution systems. The energy storage system must detect the disturbance and respond within 20 milliseconds by injecting real power for up to a few 10s of seconds to compensate for voltage sags (full outage protection is not required). Commercial installations are expected to range in size from 1 to 50 MW_{ac} in systems at voltages up to 34.5 kV.

The reference duty cycle for analysis is hot standby for infrequent events characterized by 5 seconds FPD, 1 event per hour, 5 events per day, and 100 such events per year. This application is valued at the cost of alternative solutions.

Application G: Long Duration Power Quality (LPQ) – These applications provide the functions of Application F, SPQ, plus the capability to provide several hours reserve power. The energy storage system must detect the disturbance and respond within 20 milliseconds by injecting real power for the duration of the sag, plus provide seamless transition to several hours of full power (full outage protection is required). Commercial installations are expected to range in size from 1 to 50 MW_{ac} in systems at voltages up to 34.5 kV.

The reference duty cycle for analysis is hot standby for infrequent events characterized by SPQ plus standby for 4 hours FPD, 1 event per year. This application is valued at the cost of alternative solutions.

Application H: 3-hr Load Shifting (LS3) – These applications shift several hours of stored energy from periods of low value to periods of high value. The energy storage system must be deployable on a programmed (scheduled) basis with at least 10 minutes notice and provide power for several hours when deployed. Commercial installations are expected to range in size from 1 to 200 MW_{ac} in systems at voltages up to 115 kV.

The reference duty cycle for analysis is scheduled 3-hour FPD, 1 event per day, 60 days per year. This application is valued at market rates.

Application I: 10-hr Load Shifting (LS10) – These applications shift many hours of stored energy from periods of low value to periods of high value. The energy storage system must be deployable on a programmed (scheduled) basis with at least 10 minutes notice and provide power for many hours when deployed. Commercial installations are expected to range in size from 1 to 200 MW_{ac} in systems at voltages up to 115 kV.

The reference duty cycle for analysis is scheduled 10-hour FPD, 1 event per day, 250 days per year. This application is valued at market rates.

Overview of Energy Storage Technologies

This section provides an overview of the energy storage technologies addressed in this Handbook. Detailed characterizations of each technology are provided in their respective chapters. The purpose of the following summaries is to introduce the reader to range of technologies considered the following section on the suitability of technologies for specific applications with emphasis on commercial arrangements and status.

Lead Acid Batteries (PbA)

Technology:	Vented and sealed cells with lead (negative) and lead oxide (positive) electrodes in a sulfuric acid electrolyte
Major Stakeholders:	C&D Technologies, Enersys, Exide, GNB, GS, Johnson Controls, Yuasa,
Product Lines:	Cells to ~4000Ah
Commercial Status:	Globally commercial, multiple vendors; Over $40B in all applications, estimated $1B in utility applications worldwide
Target Markets:	Dominated by vehicular (90%), with UPS (3%), telecom (3%), stationary/utility (3%) – including utililty grid support
Operating Systems:	Largest Unit: 20 MW, 20 minutes (PREPA) Most common utility applications: substation batteries (>10,000 installations in US), power plant control reserve systems

Nickel Cadmium Batteries (NiCad)

Technology:	Vented and sealed cells with cadmium (negative) and nickel oxyhydroxide (positive) electrodes in a caustic electrolyte (usually potassium hydroxide)
Major Stakeholders:	Alcad, Hoppecke, Saft
Product Lines:	Cells to ~900 A-h
Commercial Status:	Globally commercial, multiple vendors; Over $1B in all applications, over $50M in utility applications worldwide
Target Markets:	Portable, aircraft cranking, aerospace, stationary, including utility grid support
Operating Systems:	Largest Unit: 40 MW, 15 minutes (GVEA, Alaska) Most common utility applications: substation batteries (>50 installations)

Sodium Sulfur Batteries (NAS)

Technology:	Contained cell, liquid sodium (negative) and sulfur (positive) electrodes with solid (beta alumina) electrolyte operating at 290 to 360 C.
Major Stakeholders:	NGK Insulators (vendor), Tokyo Electric Power (alliance with NGK)
Product Lines:	Contained battery modules rated at 50kW, 360 to 430 kWh, capable of short duration pulses to 250 kW
Commercial Status:	Newly commercial in Japan, emerging elsewhere; Sales projected to range from $200 to $300 milllion by 2006
Target Markets:	Utility stationary power systems with unit ratings up to 100 MW, emphasis on T&D and renewable applications
Operating Systems:	Over 60 projects (including 500 kW facility at AEP); Largest facility: 6 MW, 48 MWh utility substations; Total capacity: 36 MW, 275 MWh (through March 2003)

Zinc Bromine Batteries (ZnBr)

Technology:	Flow battery with two electrolytes. Zinc (negative) and complexed bromine (positive) electrodes in aqueous electrolyte (zinc bromide).
Major Stakeholders:	ZBB Energy Corporation
Product Lines:	Containerized systems rated at 250 kW, 500 kWh
Commercial Status:	Beta prototype stage; Projected to sell more than 50 modules, 50 MWh per year
Target Markets:	Utility T&D and renewable applications
Operating Systems:	Operating Demonstration Systems: Detroit Edison 400kWh system, United Energy 400 kWh system

Vanadium Redox Batteries (VRB)	
Technology:	Flow battery with two electrolytes from vanadium salts in dilute sulfuric acid solutions with ion conductive membrane separator
Major Stakeholders:	VRB Power Systems, Sumitomo Electric, Reliable Power
Product Lines:	250 kW stack with custom energy storage tanks
Commercial Status:	Early commercial
Target Markets:	Utility T&D and renewable applications
Operating Systems:	Demonstrations in Japan include units 1.5 MW, 1.5 MWh (plus 3MW for 1.5 sec) and 0.5 MW, 5 MWh U.S. demonstration unit (PacifiCorp) of 250 kW, 500 kWh
Polysulfide Bromide Batteries (PSB, also known as Regenesys)	
Technology:	Flow battery with two electrolytes from sodium salts (polysulfide, bromide) in solution with ion conductive membrane separator
Major Stakeholders:	Innogy (owned by RWE)
Product Lines:	50 MW system with integrated PCS under development
Commercial Status:	Pre-commercial. Commercial orders projected for 2006
Target Markets:	Utility T&D and renewables applications
Operating Systems:	Laboratory demonstrations. 12 MW / 100 MWh units under construction in U.K. and U.S. (TVA)
Superconducting Magnetic Energy Storage (SMES)	
Technology:	Superconducting coil of niobium and titanium alloy, refrigerated to ~ 4 degrees Kelvin
Major Stakeholders:	American Superconductor, Inc.
Product Lines:	D-SMES: 3 MW / 3 MJ with integrated PCS, trailer mounted container
Commercial Status:	Commercial

Target Markets:	Commercial power quality, Utility grid support
Operating Systems:	9 D-SMES (27 MW), 12 micro-SMES projects
Flywheel Energy Storage (FES)	
Technology:	Rotating mass connected to a motor/generator assembly
Major Stakeholders:	Active Power, Beacon Power, Pentadyne, Piller, Satcon, Urenco
Product Lines:	High-power, short-duration products ranging from 100kW to 2000kW, usually for less than 30 seconds
Commercial Status:	Commercialized in US, Japan, Europe; emerging elsewhere; Projected to sell over 1,000 systems per year, estimated rated capacity of 250MW, retail value exceeding $50 million by 2006
Target Markets:	Utility power quality, T&D, renewable applications
Operating Systems:	Large systems: Urenco 1MW at New York City Transit; Piller 10MW data center backup Power quality: >100 installations
Electrochemical Capacitor Energy Storage (ECES)	
Technology:	Capacitative energy storage in electrical double layer at interface of electrolyte with high-surface area carbons
Major Stakeholders:	ELIT, ESMA, Maxwell, NESS, NEC Tokin, Okamura Laboratory, Panasonic
Product Lines:	Individual cells up to 100,000 F with voltage up to 2.7 V_{dc}; modules up to 300 F, with voltage up to 400 V_{dc}
Commercial Status:	Commercialized in US, Japan, Russia, and EU, emerging elsewhere; Over $30 million in all applications and $5 million in utility applications by 2006
Target Markets:	Portable electronics, automotive (hybrid electric vehicles), utility (power quality, T&D stability)
Operating Systems:	Demonstration systems: Electric rail traction systems (Switzerland), 100kW ASD ride-through, 1MW transmission stabilization development (TVA)

Compressed Air Energy Storage (CAES)

Technology:	Air compressed to 1000 to 1500 psi in small (e.g., piping) or large (geologic formations) storage chambers for use in combustion turbines
Major Stakeholders:	Alstom, Dresser-Rand, Allison, Ridge Energy Storage, Haddington Ventures, L.L.C.
Product Lines:	Site-specific engineered projects
Commercial Status:	Commercial
Target Markets:	Utility transmission, distribution and generation
Operating Systems:	2 projects to date: 290 MW_{ac} Huntorf Plant (Germany), 110 MW_{ac} McIntosh Plant (US)

Energy Storage Technology Suitability for T&D Applications

The suitability of the energy storage technologies addressed herein for T&D applications is summarized in Table 3-5. This characterization is based on technical reviews and screening economic analyses conducted by the contributors to this Handbook. The reader will find a detailed economic assessment in the respective technology chapters for each technology/application combination indicated by a checkmark "✓" (for benefit to cost ratios greater than 1.0) or an "M" (marginal, for ratios less than 1.0, but deemed to have economic potential for reasons described within the technology chapter). This framework is intended as a guide for use in the initial consideration of energy storage systems within T&D applications and should not be viewed as a constraint on the applicability of a technology.

Table 3-5
T&D Application – Energy Storage Technology Suitability Matrix

Category			Application	PbA	NiCad	NAS	ZnBr	VRB	Regenesys	SMES	Flywheels	Ultracaps	CAES (10 MW above grade)	CAES (135 MW below grade)
Grid Stabilization (GS)			A: Angular Stability (GAS)	✓	M		M			✓	✓	✓		
Grid Stabilization (GS)			B: Voltage Stability (GVS)	✓						M		M		
Grid Stabilization (GS)			C::Frequency Excursion Suppression (GFS)	M	M									
Grid Operational Support (GOS)			D: Regulation Control (RC)											✓
Grid Operational Support (GOS)			E: Cnvntnl Spinning Reserve (SR)											
Distribution Power Quality (PQ)			F: Short Duration PQ (SPQ)	✓	✓	✓	✓			✓	✓	✓		
Distribution Power Quality (PQ)			G: Long Duration PQ (LPQ)	M										
Load-Shifting (LS)			H: 3 hr (LS3)										✓	
Load-Shifting (LS)			I: 10h (LS10)			✓		✓	✓				✓	✓
Combined Applications	"T" Utility	C1: GFS +	GAS+ GVS+ RC	M	M	M								
Combined Applications	"D" Utility	C2: SPQ +	LS10 + RC + SR			✓		✓	✓					
Combined Applications	"D" Utility	C3: SPQ +	LS3 + RC + SR	✓	✓	✓	✓	✓	✓					
Combined Applications	"D" Utility	C4: LPQ +	LS3 + RC + SR	✓		✓		M	✓					
Combined Applications	"T" or "D"	C5: LS10 +	RC + SR			✓	M	✓	✓				✓	✓

Table 3-5 also introduces "combined function applications" which address energy storage systems adapted to serve multiple functions (e.g., combined power quality, load shifting, and grid support). In the analysis of combined function applications, it is necessary to define functional priorities. The priority applications for applications C1 through C5 are GFS, SPQ, SPQ, LPQ and LS10; respectively. The approach used herein is to first size the reference energy storage system to meet the requirements of the priority application and then add functions incrementally (in the order listed), to identify an economic optimal configuration that utilizes system attributes (e.g., cycle life) to the fullest extent practical. In doing so, care is taken to realistically estimate the implications of the combined duty cycles in terms of managing the state-of-charge, thermal or flow management and cycle life.

Unless otherwise justified, cycle life is evaluated by the following cumulative damage model:

$$D = \sum_{i=1}^{m} N_i \frac{1}{C_{L,i}}, \; D < 1.0 \qquad \textbf{Eq. 3-1}$$

Where D is summed over m cyclic duty cycles (e.g., load shifting, regulation control, etc.), N_i is the number cycles corresponding for the i^{th} duty cycle, and $C_{L,i}$ is the cycle life corresponding the depth of discharge for the i^{th} duty cycle as illustrated in Figure 3-10. Loading combinations are defined such that D is less than 1.0 for the battery life [17].

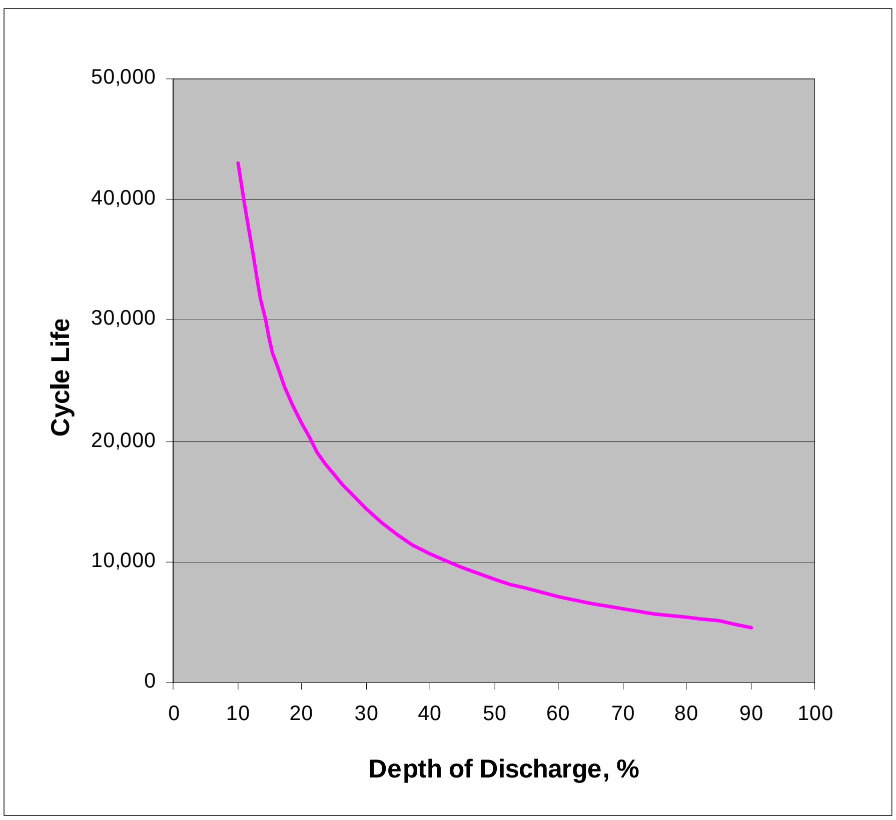


Figure 3-10
Example: Battery Cycle Life vs Depth of Discharge

Application Summary Descriptions

For consistency, the following summaries of the foregoing applications appear in the applications assessment sections for each energy storage technology in their respective chapters. The applications addressed for that technology are indicated by a border enclosing the summary.

Single Function Applications

Application A: Grid Angular Stability (GAS) – mitigation of power oscillations by injection and absorption of real power at periods of 1 to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 20 oscillatory cycles, cumulatively equivalent to a full power discharge (FPD) of 1 second duration and subsequent charge cycle; 1 event per day; 10 events per year. Valued at the cost of alternative solutions.

Application B: Grid Voltage Stability (GVS) – mitigation of degraded voltage by additional reactive power plus injection of real power for durations up to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 1 second FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application C: Grid Frequency Excursion Suppression (GFS) – "prompt" spinning reserve (or load) for mitigating load-generation imbalance. Requires energy storage to discharge real power for durations up to 30 minutes. The reference duty cycle for analysis is standby for infrequent events characterized by 15 minute FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application D: Regulation Control (RC) – system frequency regulation in concert with load following. The reference duty cycle for analysis is characterized by continuous cycles equivalent to 7.5-minute FPD and charge cycle (triangular waveform), 2 cycles per hour deployed with 10 minutes advance notice. Valued at market rates.

Application E: Spinning Reserve (SR) – reserve power for at least 2 hours with 10 minute notice. The reference duty cycle for analysis is standby for infrequent events characterized by 2 hour FPD, 1 event per day, 10 events per year. Valued at market rates.

Application F: Short Duration Power Quality (SPQ) – capability to mitigate voltage sags (e.g. recloser events). The reference duty cycle for analysis is standby for infrequent events characterized by 2 seconds FPD, 1 event per hour, 5 events per day, 100 events per year. Valued at the cost of alternative solutions.

Application G: Long Duration Power Quality (LPQ) – SPQ, plus capability to provide several hours reserve power. The reference duty cycle for analysis is standby for infrequent events characterized by SPQ plus standby for 4 hours FPD, 1 event per year. Valued at the cost of alternative solutions.

Application H: 3-hr Load Shifting (LS3) – shifting 3 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 3-hour FPD, 1 event per day, 60 events per year. Valued at market rates.

Application I: 10-hr Load Shifting (LS10) – shifting 10 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 10-hour FPD, 1 event per day, 250 events per year. Valued at market rates.

Combined Function Applications (In the Order Noted)

Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC)

Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR)

Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR)

Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR)

Application C5: Combined Applications I, D, E (LS10 + RC + SR)

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4

ENERGY STORAGE BENEFITS AND BENEFIT QUANTIFICATION

Introduction

Chapter 2 provides a National perspective on the benefits of electrical energy storage for T&D applications as well as for other utility and consumer applications. This chapter more specifically addresses the benefits associated with the T&D applications identified in Chapter 3 and the approach for quantifying such benefits for the energy storage technologies in their respective chapters.

Table 4-1 shows how the specific categories of benefits align with the different combinations of transmission (T) and distribution (D) utility host beneficiaries, including those with and without a generation (G) based business. Also included in Table 4-1 is the consumer host beneficiary, which provides indirect infrastructure upgrade deferral benefits to the T and D utilities. The value components are summarized below and discussed and quantified in the remaining sections:

- Deferral or avoidance of the alternative upgrade or solution net costs, which may include components from the T, D or G sectors of the business, e.g., providing a power quality solution plus a substation upgrade deferral.
- Energy costs savings (or arbitrage) from the displacement of more expensive peak energy with less expensive off-peak energy.
- "T" peak demand reduction and hence, T demand charge reduction for a separate D based utility.
- Ancillary services, specifically regulation control and spinning reserve.

The ability of the various T and/or D based utilities to realize the benefits are noted as being within current regulations as opposed to requiring enlightened regulations, that are needed (and would be generally applicable) for all utility-based distributed resources. In addition, the table notes indirect benefits that accrue to the non-host beneficiaries as a result of the host deploying energy storage.

Table 4-1 highlights the ability of the vertically integrated utility (TDG) to realize the maximum direct benefits from energy storage ownership, and the various combinations of T and/or D, with and without G, based utilities. Note that a T- and/or D-based utility, without also being a G-based utility, requires enlightened regulations to accrue the arbitrage and the regulation and spinning reserve type of ancillary services benefits, which can make the difference in achieving attractive economics for the T and/or D utility's decision to deploy an energy storage based system. Also note that if a T- and/or D-based utility would deploy energy storage, there are indirect benefits to the G utility related to deferring or avoiding additional peaking capacity and/or achieving a higher load factor on existing generation plants, either of which contribute to lower generation costs. Until such enlightened regulations are in-place, energy storage applications that include displacement of peak with off-peak energy, regulation and spinning reserve opportunities for the T and/or D utilities are likely to be best targeted for those with an integrated G-based business.

Table 4-1
Values Accruing to Energy Storage System Hosts & Beneficiaries

		Host/Beneficiary of Energy Storage Installation						
		T	**D**	**TD**	**TG**	**DG**	**TDG**	**C**
Value Components	**GX**	I	I	I	X	X	X	I
	TX	X	I	X	X	I	X	I
	DX		X	X		X	X	I
	EN	O	O	O	X	X	X	X
	DD							X
	TD		X			X		X
	RC/SR	O	O	O	X	X	X	I

Legend

"X" denotes value component within current regulations accruing to Host
"O" denotes potential value component accruing to Host with favorable DR regulations
"I" denotes indirect value component accruing to non-Host

Hosts/Beneficiaries		Value Components	
T	Transmission Utility	**GX**	Generation Deferral
D	Distribution Utility	**TX**	Transmission Deferral Value
G	Generation Utility	**DX**	Distribution Deferral Value
TD	T&D Utility	**EN**	Delta Energy Cost (Peak vs Off-peak)
TG	T&G Utility	**TD**	Transmission Demand Charge
DG	D&G Utility	**DD**	Distribution Demand Charge
TDG	T, D&G Utility (vertically integrated)	**RC/SR**	Regulation Control & Spinning Reserve
C	Customer/End-User		

Alternatively, the hosting of utility-scale, grid interactive energy storage systems by the consumer (or energy service provider) can take advantage of any combination of improved power quality, reduced energy charges, reduced T and D demand charges plus the potential for added revenue from selling ancillary services and/or arbitrage, assuming the D utility is able and willing to deliver such to an open market. Note that such applications may also provide indirect upgrade deferral benefits to the local utility, depending on the utility's location-specific capability to serve the peak load and the consumer's need for energy storage backup capacity from the grid. Such factors and issues are common to other distributed generation resources which will compete with distributed storage resources.

An alternative for the local utility is to deploy such distributed resources at stressed substations as well as at select opportunity customer sites that optimize the overall benefits to both parties. The utility could own, lease or sell such distributed resources depending on mutually agreed business arrangements and regulatory provisions. To date, such a distributed resource business model for the utility has been slow to develop due, in part, to the regulatory restructuring conflict with the D utility owning distributed generation. However, D utilities can avoid this conflict with distributed storage systems, plus gain the unique storage benefits associated with prompt response, eased siting and the potential for enhanced reliability and security attributed to redundancy and diversity. Further, D utilities can deploy such systems with select customers to secure long-term service contracts, and hence deter competitive threats from independent generators/energy service providers that seek to displace the D utility, with or without an integrated G business.

Benefits From Deferral or Avoidance of Alternative Costs

A T- and/or D-based utility's decision to deploy an energy storage system will typically be evaluated against the alternative solutions, which range from traditional infrastructure upgrades/expansions to non-traditional solutions such as competing distributed generation-based alternatives. Alternatives may also include other systems that employ energy storage, e.g., a short-duration battery bridging to a standby generator to affect a UPS-type solution for a substation serving a customer(s) with premium power needs.

For the purposes of this Handbook, reference energy storage systems are identified for each energy storage technology in their respective chapters and assessed in a manner that facilitates comparison of economics with a range of alternatives. Theoretically, alternatives can be evaluated by comparing the net present value (NPV) of the reference energy storage system with those of the alternative, or by calculating benefit to cost relationships where the avoided cost (or gain) associated with the alternative is treated as a benefit (or cost) to the reference energy storage system. The latter approach has been chosen for use herein because it enables a graphical representation of a range of alternative solution costs.

Thorough NPV analyses of the reference energy storage systems have been conducted in accordance with the methodology described in Chapter 5. Equivalent analyses should be conducted on alternative solutions using the same project and financial parameters (e.g., 20-year project life, 7.5% real discount rate, etc.) to appropriately account for all lifecycle costs, including initial capital, operating, maintenance (including component replacement), and disposal costs, plus any offset benefits that may accrue to the alternative. The resulting NPV of the alternative solution, expressed as unit power cost (i.e. $/kW), may be used with the graphical representation of economic performance for the reference energy storage systems described in their respective chapters.

For purposes of illustration, a representative plot for a reference energy storage system versus an alternative is provided in Figure 4-1. The NPV of the reference energy storage system is shown as a constant negative value of about ($10) million which is then combined with the benefit of the avoided alternative ranging from $500 to $1500/kW. The convenient selection of 10 MW_{ac} for the reference power allows the reader to observe that parity would be achieved at the zero crossing point of about $1000/kW, i.e., NPV for the reference energy storage system is positive when the net capitalized unit cost for the alternative exceeds about $1000/kW. Hence, the NPV derived from the plot is simply the difference between the costs of the alternative solution and the reference energy storage system. The diligent application of consistent analysis methodology to the alternative system is critical to the usefulness of this approach.

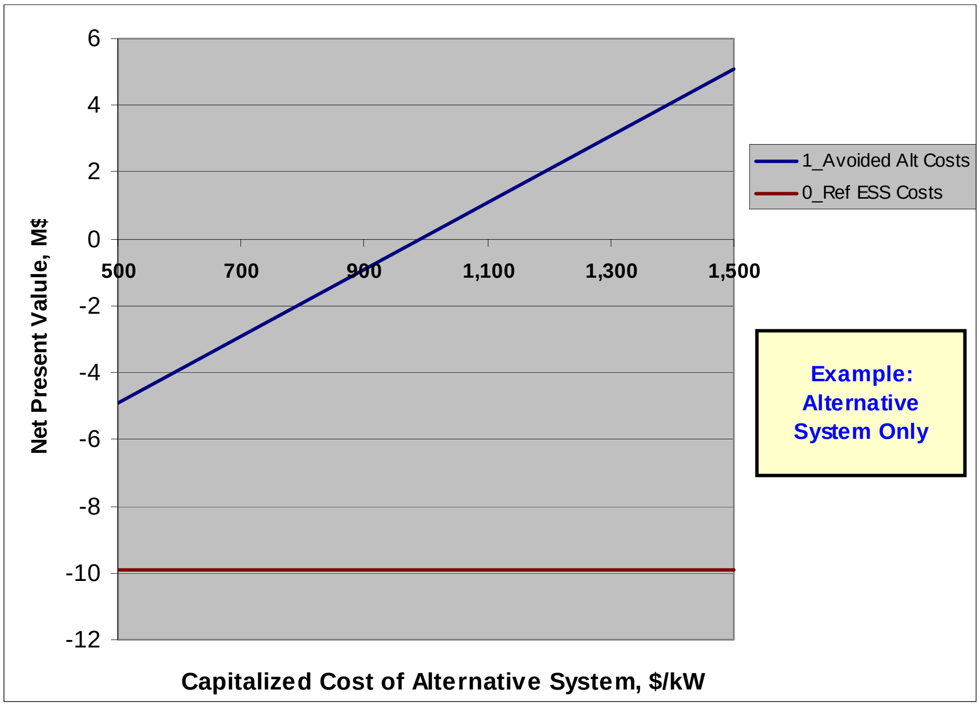

Figure 4-1
Example: Avoided Alternative System vs Reference ESS Cost

Note that the projected range of alternative solution costs presented herein are deemed to capture the target or opportunity values for market entry applications of energy storage based systems projected for the 2006 timeframe. Accordingly, the low range value should be viewed as capturing no more than about 50 percent of the attainable markets, whereas the high range is down to about 10 percent and the reference value is about 25 percent of the attainable markets. Also note that the size of the respective target applications or markets is not addressed. Some are currently niche markets, but with major market potential with the advancement of energy storage systems and regulatory arrangements.

The need for Grid Stability solutions is generally determined from extensive analysis of the specific grid configuration and loading conditions. Non energy storage alternatives are typically upgrades in the transmission and/or generation infrastructure that can vary widely in cost depending on locational factors such as permitting, rights-of-ways, etc. For Rotor Angle Stability, the avoided alternative solution may be a new transmission line, for which costs may exceed a million dollars per mile and can easily exceed 750$/kW and possibly much more in the future when opportunities to expand within existing right-of-ways have been exhausted. Accordingly, a range of 500 to 1000$/kW is used in the presentation of results of the reference energy storage systems. Similarly the options for Grid Voltage Stability (GVS) applications range from additional dynamic reactive power support to the construction of a new transmission line. Alternative reactive power is valued at $250/kW based on 150$/kVA installed costs for a distribution level STATCOM when capitalized project and operating costs are included. The value of strategic locations enabled by STATCOM with energy storage may easily double the value of that solution. Thus, a range of 250 to 750$/kW should be used for GVS analysis. For the Grid Frequency Suppression application, the typical alternative cost of added generation for spinning reserve is about 750$/kW, which includes any increments or decrements associated with the spinning reserve operating mode. Alternatively, a transmission upgrade may be applied. In either case, a range of 500 to 1000$/kW should be applied.

For Power Quality applications, the alternatives for the T and/or D based utility typically start with dual and diverse (to the extent possible) feeds with a static switch which altogether cost in vicinity of 1000$/kW. High end manufacturers (e.g., semiconductor industry) may then supplement this power supply with one of many power quality solutions that have evolved for utility substation and customer site entry applications. Leading examples include lead acid battery based UPS system with an option for backup generation, and various flywheel based UPS systems also with options for backup generation for which net capitalized unit costs are at least 500$/kW. Hence, a full range of 500 to 1500$/kW is applicable for the premium SPQ market. It is noted that the practice within the telecom industry for high reliability and power quality is traditionally based on 4 to 8 hours of lead acid batteries plus N+1 backup generators which can easily add 500$/kW to this cost range for LPQ applications.

For Load Shifting applications, typical alternatives are conventional substation upgrades, where target markets may entail a larger transformer, conductor upgrades or added lines on existing towers and corridors or, in the extreme, new rights-of-ways, towers, etc. The latter are becoming prohibitively expensive in metropolitan area transmission corridors where relief is needed most. A survey of T and D upgrade costs are reported in [1] and summarized in Table 4-2.

Table 4-2
Incremental T&D Expansion Cost for New Peak Load at Several U.S. Utilities, $/kW

U.S. Utility Location	Low	High
Northeast	166	925
Southeast	45	729
Central Plains	82	336
West Coast	64	610

As noted in Chapter 2, more detailed estimates of upgrades in California are typically about 650$/kW for T and D infrastructure and about 1000$/kW for the high 90 percentile D infrastructure [2]. Altogether, a range of 500 to 1000 $/kW should be applied with a reference of 750 $/kW.

These examples are listed in Table 4-3 and provide the bases for the range of alternative solution values used in this Handbook. Single point analyses are based on the nominal NPV of the alternative solution and results are shown graphically for the range. Note that the combined applications may apply two deferral benefits (e.g., combined LPQ, LS3, RC and SR), where both LPQ and LS3 warrant alternative solution benefits. For ease of comparisons, the reference value is maintained, with the upper range considered sufficient to capture reasonable combinations of both benefits.

Table 4-3
Valuation of Alternative Solutions

<table>
<tr><th colspan="3">Category</th><th>Application</th><th>Reference Alternative System & Nominal NPV</th><th>Value Range Used in Economic Assessments, $/kW</th></tr>
<tr><td colspan="3" rowspan="3">Grid Stabilization
(GS)</td><td>Angular Stability (GAS)</td><td>Transmission and/or generation upgrade
~$750/kW</td><td>500 to 1000</td></tr>
<tr><td>Voltage Stability (GVS)</td><td>Locational access driven VAR support
~$500/kW</td><td>250 to 750</td></tr>
<tr><td>Frequency Excursion Suppression (GFS)</td><td>Spinning reserve and/or transmission upgrade
~$750/kW</td><td>500 to 1000</td></tr>
<tr><td colspan="3" rowspan="2">Grid Operational Support
(GOS)</td><td>Regulation Control (RC)</td><td colspan="2" rowspan="2">NA
(valued at market rates)</td></tr>
<tr><td>Cnvntnl Spinning Reserve (SR)</td></tr>
<tr><td colspan="3" rowspan="2">Distribution Power Quality
(PQ)</td><td>Short Duration PQ (SPQ)</td><td>Dual feeds plus short duration energy storage DPQ system
~$1000/kW</td><td>500 to 1500</td></tr>
<tr><td>Long Duration PQ (LPQ)</td><td>Above plus genset(s)
~$1500/kW</td><td>1000 to 2000</td></tr>
<tr><td colspan="3" rowspan="2">Load-Shifting
(LS)</td><td>3 hr (LS3)</td><td rowspan="2">Substation upgrade
~$750/kW</td><td rowspan="2">500 to 1000</td></tr>
<tr><td>10 hr (LS10)</td></tr>
<tr><td rowspan="5">Combined Applications</td><td>"T" Utility</td><td>GFS+</td><td>GAS+
GVS+
RC</td><td>Additional generation for spinning reserve and VAR support
~$750/kW</td><td>500 to 1000</td></tr>
<tr><td rowspan="3">"D" Utility</td><td>SPQ +</td><td>LS10 +
RC +
SR</td><td>Dual feeds and/or short duration energy storage DPQ system and/or substation upgrade
~$1500/kW</td><td>1000 to 2000</td></tr>
<tr><td>SPQ +</td><td>LS3 +
RC +
SR</td><td>Dual feeds plus short duration energy storage DPQ system and/or substation upgrade
~$1500/kW</td><td>1000 to 2000</td></tr>
<tr><td>LPQ +</td><td>LS3 +
RC +
SR</td><td>Above plus genset(s)
~$2000/kW</td><td>1500 to 2500</td></tr>
<tr><td>"T" or "D"</td><td>LS10 +</td><td>RC +
SR</td><td>Substation upgrade
~$750/kW</td><td>500 to 1000</td></tr>
</table>

Benefits From Peak Energy and Demand Cost Savings

As previously noted, the value of load shifting is temporal in that periods of high value generally coincides with high daily or seasonal demand that must correspond with daily intervals of low demand to allow economic recharging. These factors tend to be obscured in utility tariffs which try to avoid exposing the consumer to sharp price differentials. Nonetheless, opportunities to exploit the intrinsic value exist whenever such circumstances occur.

As previously described, two representative and bounding profiles have been selected. The first assumes a short 3 hour mid-day peak for a seasonal 60 days per year (or 12 weeks and 5 work-days per week), hence relatively low energy discharge and low discharge-charge cycle duty. The second assumes a long 10 hour day-long peak for a year-round 250 days per year (or 50 weeks and 5 work-days per week), hence relatively high energy discharge and high discharge-charge cycle duty. The first is more typical of substation profiles serving a short energy intensive process such as occurs at water treatment facilities during evening hours that coincide with high residential demand for electricity. The second is more likely encountered with commercial loads without strong seasonal heating and cooling loads. In either case, the peak and off-peak energy rates are more indicative of a time-of-use rate (reflecting the utility's cost based values) as compared to the more typical time-of-day based rate that blunts the advantage for such load shifting.

Table 4-4
Valuation Parameters for Energy and Demand Load Shifting

Parameter	LS3	LS10
On-Peak Interval, Hours	3	10
Daily Cycles per Year	60	250
On-Peak Energy Rate, $/MWh	120	80
Off-Peak Energy Rate, $/MWh	20	
Transmission Demand Charge, $/kW-mo	5	

The values shown in Table 4-4 were selected as representative of target opportunities for load shifting that also provide a convenient basis for extrapolating analytical results to specific projects of interest to the reader. The graphical presentation of results for the evaluation of alternative solutions presented in the previous section is extended to include energy and demand charge values in Figure 4-2. Note that these value parameters parallel the value attributed to the alternative solution and contribute about $4.5 million increased NPV to the reference energy storage system. By observing the zero crossing point, it can be seen that the NPV corresponding to parity with alternative systems is decreased from about $1000 to $550/kW. In this example, it is assumed that the alternative system is the same as that represented in Figure 4-1 and does not provide load shifting functions. Hence, the energy storage based solution is now much more attractive. Note that the reader can apply these figures for his own circumstances by extrapolating differences in energy savings and/or the T demand charge. Alternatively, if the alternative solution did provide a different degree of load shifting capability, the net benefits would be included to reduce the net capitalized costs of the alternative.

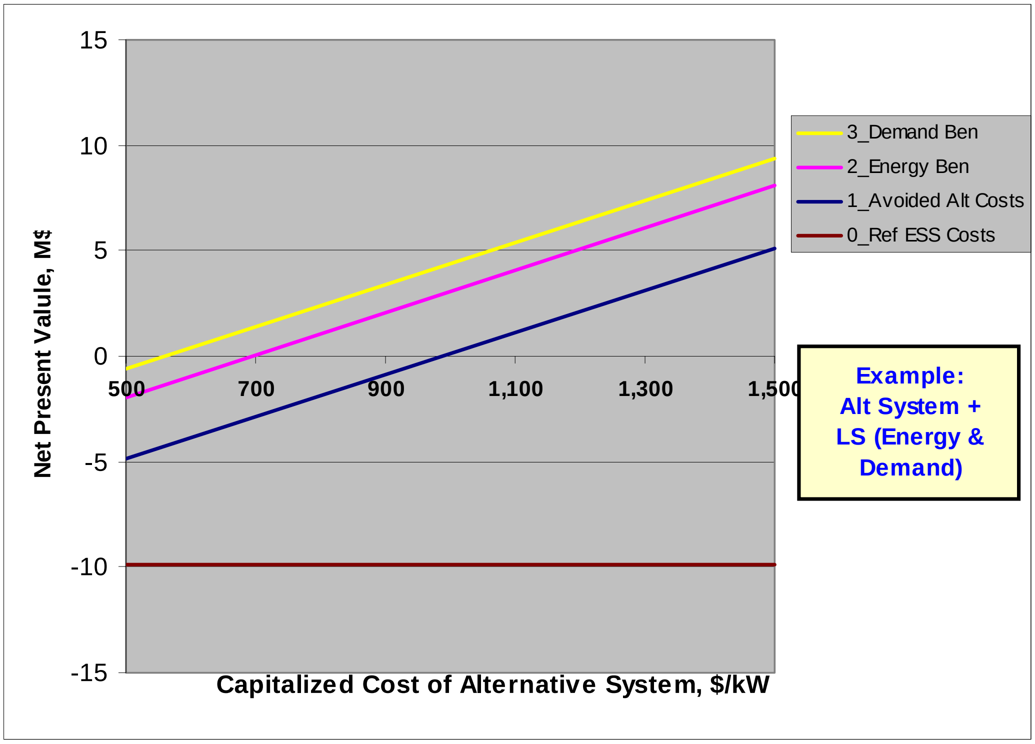

Figure 4-2
Example: Alternative vs Reference ESS Plus Energy and Demand (LS) Value Components

Ancillary Services Benefits

A generator has to be on-line, selling at least its minimum running energy, and selling less than its maximum energy in order to be able to sell regulation or spinning reserves. When a generator has to forgo energy sales in order to sell ancillary services, the generator's bid price becomes more a function of the lost energy sales opportunity than the direct cost for supplying the service. Hence, ancillary service prices are often more volatile than energy prices [3]. Figure 4-3 presents average hourly ancillary service prices for California in 2002[5], which are typical for the other open markets [4].

Not surprisingly the faster response services command higher prices. Also, not surprisingly, prices for contingency reserves vary hourly and show a daily pattern that mirrors the daily fluctuation of energy prices. Prices for regulation remain high at night because regulation requires that suppliers be able to move down as well as up. Downward capacity is scarce at night when most generation is lightly loaded.

[5] Again, service names vary from region to region. California uses the terms "Spinning", "Non-Spinning", and "Replacement" for the contingency reserves. California also splits regulation into up and down. The average of up and down are presented here.

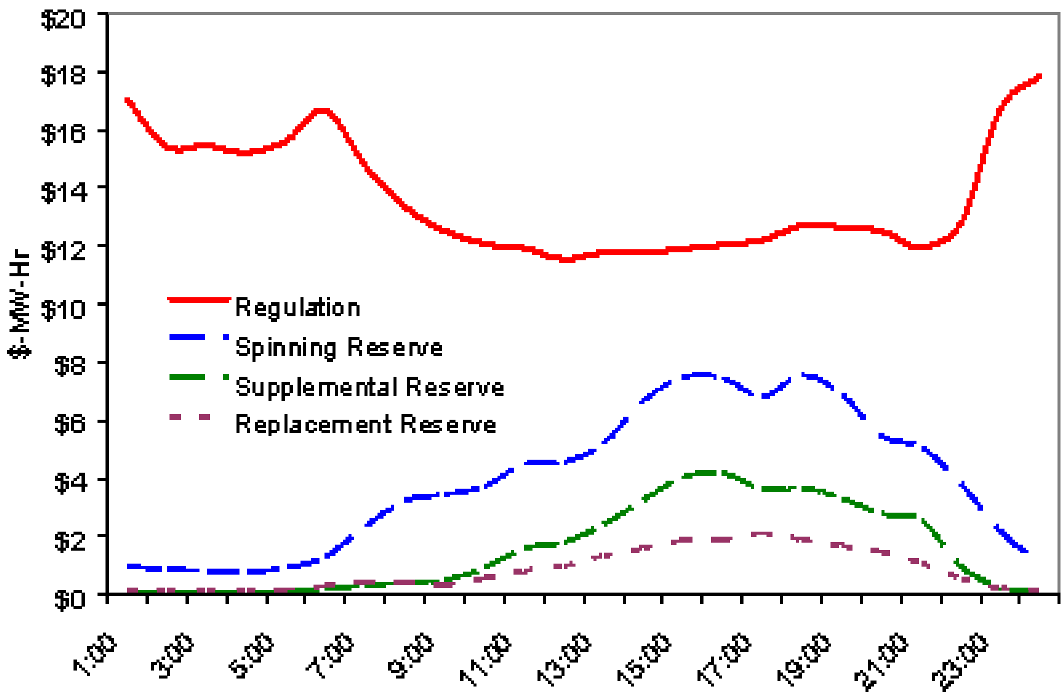

Figure 4-3
California 2002 Average Hourly Ancillary Service Prices

Ancillary services are predominantly capacity services rather than energy services. When a generator supplies regulation, it moves above and below a base operating point. The energy supplied at the base operating point is not related to regulation, but the generator must be operated above its minimum power limit and any generation is sold into the energy market. The energy component of the regulation service nets out to zero energy over a few hours as the generator maneuvers above and below the base operating point. Storage can supply regulation without the need to be simultaneously supplying energy. A storage project can vary its output around zero – acting as a generator at times and acting as a load at other times. The energy required to offset the turnaround efficiency penalty could be purchased by the storage project from the energy market or could be supplied to the project by the system operator. This added cost is similar to a generator's added cost associated with the degraded heat rate that comes from controlling the unit at low power levels. These added costs are one reason that regulation is the most expensive ancillary service.

Contingency reserves are also predominantly capacity services. They are required to be continuously available (capacity) but deployed infrequently (energy). The cost of the energy content is typically valued at the spot market energy price or at the resource's bid price when the reserve is deployed. Reserves are priced per unit of power (e.g. MW) <u>available</u> for a unit of time (e.g. hour) and are presented as $/MW-hr, i.e., the price for 1 MW of the service supplied for a period one hour. Power <u>availability</u> expressed in terms $/MW-hr is distinguished from energy prices expressed in terms of $/MWh, which represents the unit value of power delivered during a time interval.

Table 4-5 compares the prices of ancillary services in California and New York for 2002 [4, 5]. Regulation, which requires continuous and rapid control, commands the highest price in both markets; six times the price of spinning reserve in New York and four times the price in California. Based upon price, the faster response services are more attractive services for energy storage to supply. Note that the spinning reserve prices are twice as high as the supplemental reserve prices. As will be discussed later, the shorter deployment durations are also better matched to the capabilities of many energy storage systems. However, the high cycling requirements associated with regulation may limit the operational life of some storage technologies; hence the duty cycle must be considered.

Table 4-5
California and New York Average Ancillary Service Prices for 2002

Service	NY East $/MW-hr	NY West $/MW-hr	CA $/MW-hr
Regulation	$18.63	$18.63	$13.69
Spinning Reserve	$3.04	$2.82	$3.89
Supplemental Reserve	$1.51	$1.37	$1.57
Replacement Reserve	$1.23	$1.23	$0.86

Ancillary services prices are typically volatile. Figure 4-4 shows that contingency reserve prices are frequently modest but are occasionally quite high for regulation and spinning reserves [4]. When generators are on line but not fully loaded their costs (hence their bid prices) to provide contingency reserves can be nearly zero. However, when generation is scarce, capacity is expensive and lost opportunity costs are high. Regulation prices show a more gradual price rise because regulation must come from generators with both head room and foot room, i.e., the generators must be able to both increase and decrease power generation within their operating range.

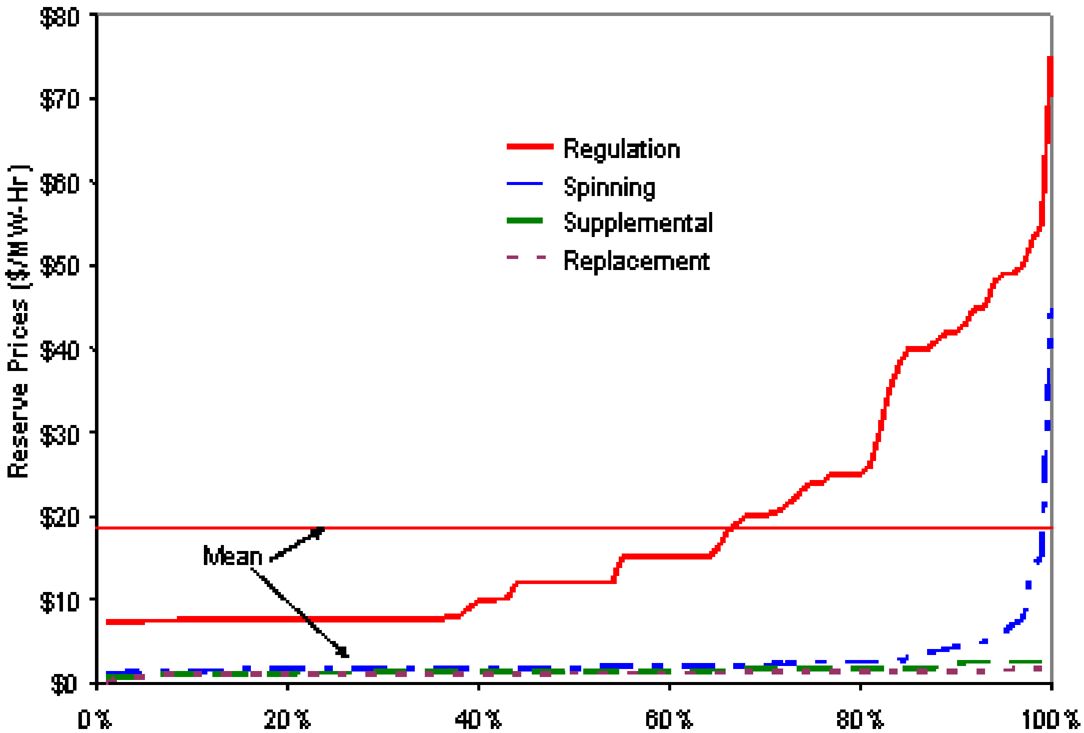

Figure 4-4
Ancillary Services Prices in New York in 2002

For the purposes of this Handbook, an average price of 16$/MW-h for regulation control and 3$/MW-h for spinning reserves is applied to the rated energy storage capacity as the basis for the respective benefit assessment. The daily duration of regulation control may be limited by the properties of the energy storage technology, e.g., the period of time necessary for thermal, flow and state-of-charge management. Also, the total annual duration allocated for regulation control may be limited by the cycle life of the energy storage equipment. The cost to replenish stored energy is calculated at off-peak rates and deducted from the benefit. Based on current interpretations of evolving ISO tariffs, the capacity-based value of regulation control is limited to 50% of the full power charge/discharge range of the system (e.g., for a system rated at 10 MW, 50% of the range from +10 MW during discharging to -10MW during charging), which is equal to the 10 MW rated power of the system.[6] The categories of supplemental and replacement reserves are ignored in light of the much lower values and the preference for providing the higher value spinning reserves.

The graphical presentation of results for the evaluation alternative solutions (Figure 4-1) and adapted to include energy and demand charge values in Figure 4-2 has been further extended to illustrate the inclusion of benefits associated with regulation control and spinning reserve in

[6] For conservatism in projecting the cycle life of energy storage media, the depth of discharge for a regulation control cycle is calculated on the basis of full rated power of the system, i.e., from +10 MW during discharging to -10MW during charging in the above example.

Figure 4-5. These value elements add about $1 million to the NPV of the reference energy storage system, resulting in parity with the alternative system at values slightly less than $500/kW (the zero crossing point). Readers can apply any combination of such benefits based on utility specific circumstances - as well as extrapolate any benefit based on different parameters.

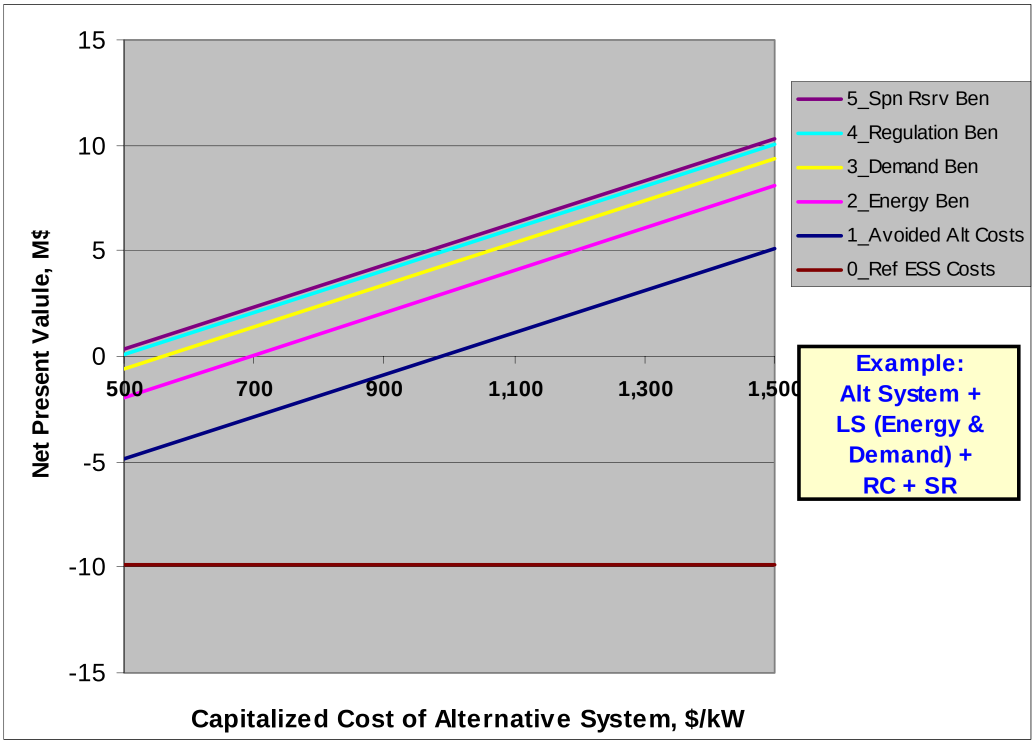

Figure 4-5
Example: Alternative s Reference ESS Plus LS, RC and SR Value Components

Voltage control and black start are currently not traded in hourly markets in the U.S. Both services are more location dependent than regulation or contingency reserves and are typically procured through long-term contracts on a locational basis. Accordingly, both are not included in the benefit assessment framework of this Handbook. However, these possible applications for energy storage may warrant inclusion in a more detailed treatment for a utility's deployment decision analyses, if there is a locational need and value for either.

References

1. Distributed Power Generation: Planning and Evaluation; H. Lee Willis and Walter G. Scott; Marcel Dekker, Inc.; 2000.

2. California Energy Commission Solicitation for Energy Storage Demonstration Projects, Appendix 14. http://www.energy.ca.gov/contracts/RFP_500-03-501/2003-07-31_RFP_500-03-501.PDF.

3. E. Hirst and B. Kirby 1997, Creating Competitive Markets for Ancillary Services, ORNL/CON-448, Oak Ridge National Laboratory, Oak Ridge TN, October.

4. CAISO (California Independent System Operator) 2003, www.caiso.com, California Independent System Operator, Folsom, California.

5. NYISO (New York Independent System Operator) 2003, www.nyiso.org, New York Independent System Operator, Albany, New York.

5 COMMON FINANCIAL PARAMETERS AND COST ELEMENTS

The purpose of this Handbook is to provide insight to the technical and economic potential of emerging energy storage technologies for the applications and benefits described in Chapters 3 and 4. The approach used herein is, to the extent practicable, based on applying a consistent set of financial parameters and assumptions on system acquisition and operating costs. The financial ground rules and methodology used to characterize lifecycle costs and benefits are described in below.

This chapter also describes the approach to configuring “integrated energy storage systems” for technologies in a consistent manner, and to assigning costs to common elements for use in the detailed economic assessments described in the respective technology chapters. For the purposes of this Handbook, an “integrated energy storage system” consists of three subsystems:

- The Energy Storage System (ESS), consisting of all equipment necessary to store and supply energy to the power conversion system interface in accordance with the requirements of the application duty cycle. Guidelines for the ESS are described.
- The Power Conversion System (PCS), consisting of all equipment necessary to supply energy from the utility grid to the ESS and to discharge stored energy to the grid. The PCS establishes the electrical interface between the ESS and the utility grid up to the point of common coupling in accordance with the application duty cycle. To achieve consistency among energy storage technologies, detailed guidance for PCS functional requirements and costs are provided.
- The Balance of Plant (BOP), consisting of the owner’s costs for project engineering and construction management, grid connection (including transformer(s)), land, access, and services; plus any additional assets and services required (e.g., foundations, buildings, aspects of system integration, etc.) not deemed to be within the usual scope of supply of PCS and ESS vendors. Guidelines are provided below and elaborated as appropriate for each energy storage technology within the respective technology chapters.

Financial Ground Rules and Methodology

Lifecycle benefit-cost analyses of the technologies and applications addressed in this Handbook are applied to 10 MW_{ac} (unless specified otherwise) commercial units. That is, first-of-a-kind and prototyping costs are assumed to have been resolved in prior projects. System commissioning is assumed to occur in June of 2006, and the financial life of the project is 20 years. Replacement costs, if any, are incurred at fully matured values projected for 2010 and beyond. Additional ground rules used in the analyses herein include the use of constant 2003 dollar value, a real discount rate of 7.5%, and annual property taxes and insurance costs applied at an annual rate of 2% of initial capital costs. These data are summarized in Table 5-1.

Table 5-1
Financial and Project Parameters

Dollar Value (Year)	2003
System Startup Date	June 2006
Project Life, Years	20
Real Discount Rate, %/yr	7.5
Property Taxes & Insurance, %/yr	2
Fixed Charge Rate, %/yr (before income taxes)	9.81

The following expression is the general equation for calculating the present value of costs or benefits:

$$PV = \sum_{t=0}^{n} \frac{X_t[(1+i)(1+e)]^t}{[(1+r)(1+i)]^t} \qquad \textbf{Eq. 5-1}$$

Where:

PV = Present Value (of a series of cost or benefit components, X_t)

X_t = Cost or Benefit (occurring during the time period, t)

n = Number of Time Periods

e = Real Escalation Rate (see discussion below)

r = Real Discount Rate

i = Inflation Rate

t = Time Period

The real escalation (or de-escalation) rate addresses projected real changes in costs or benefits related to scarcity (or over supply) that are not included in the base estimates of the costs and benefits. Unless specified otherwise, for the technologies considered in this Handbook, present value calculations are based on the assumption that real escalation rates are zero, i.e., that differentiating factors such as scarcity or changes in manufacturing methods have already been included in the base cost and benefit estimates. This simplification allows present values to be calculated with the following equation (i.e., constant dollar analysis):

$$PV = \sum_{t=0}^{n} \frac{X_t}{[(1+r)]^t} \qquad \textbf{Eq. 5-2}$$

Guidelines for Energy Storage System Costs

The respective technology chapters describe the cost and performance parameters associated with integrated energy storage systems configured to meet the requirements of applications identified in Chapter 3. Based on the best available contributions from the ESS vendor/developers and others, the following data have been developed for use in lifecycle benefit-cost analyses:

ESS Scope of Supply and Capital Costs

- Energy storage units or "reservoirs"(i.e., components that "store" the energy as distinct from components that convert the form of the energy)
- Interconnections, electrical or otherwise, e.g., cabling, piping, etc.
- Support structures, e.g., racks, module housings, containment vessels, etc.
- Ancillary equipment integral to and/or unique to the ESS, e.g., vacuum pumps, cooling or heating systems, etc.
- Monitoring/management systems, e.g., voltage, current, temperature, flow management
- ESS isolation and protective devices, e.g., switches, DC breakers, fuses
- Duties, shipping and installation[7]
- On-site engineering support for installation and startup.[1]

ESS Operating, Maintenance and Equipment Replacement Costs

- Fixed operation and maintenance (O&M) costs in accordance with a planned maintenance program.[1]
- Variable O&M costs, accounting for ESS and power conversion inefficiencies and standby losses, e.g., self discharge, shunt current losses, pumping losses, battery thermal management losses, etc.
- Component replacement or refurbishment based on cycle and/or calendar life limits.[1]

[7] In the absence of reviewable data for specific energy storage technologies, best judgment values of industry average performance for similar technologies have been used in analyses.

ESS-PCS and BOP Interface Requirements

- PCS technical interface requirements, e.g., maximum charging and minimum discharging voltage at the ESS interface, system isolation and grid connection device. Such information is used to assign PCS costs as described below.
- Weight and space requirements, including access for installation, maintenance and replacement. This information is used to account for foundations, buildings and enclosures not included in the ESS scope of supply.

Functional Requirements and Costs for Power Conversion Systems

Top-level PCS functional requirements for the applications considered herein are introduced in Chapter 3. Since the emphasis of this Handbook is on emerging energy storage media, the cost of PCS has been normalized to achieve uniformity.[8] However, representative cost differentials between the functional attributes required by different applications and by different interface conditions imposed by the various energy storage media are needed to characterize relative economics. Examples of application-induced differences imposed on PCS include the prompt response (<20 msec) required of GS applications in contrast with the programmed response appropriate for LS applications (≤ 10 minutes). The former requires that the PCS be equipped with controls and instrumentation to detect and mitigate power disturbances within about one cycle, while the latter allows a scheduled rise to power and grid synchronization with the grid in response to notification by the system operator.

Similarly, the technical attributes of the various energy storage systems may impose different demands on PCS for the same application. For example, nickel-cadmium batteries are capable of string voltages in excess of 4000 V, while sodium-sulfur batteries are currently limited to about 2000 V. Also, “pulse power” capability, which determines the minimum discharge voltage for some applications, varies among the energy storage technologies. Three types of electronic PCSs have been identified for the purpose of achieving consistency in assumptions pertaining to performance and cost. Their attributes are discussed in the following paragraphs and summarized in Table 5-2.

- Type I PCS, Prompt Continuous, is required for applications that must respond within 20 milliseconds and provide continuous supply and control of real and reactive power for durations greater than 30 seconds, e.g., GFS and LPQ applications. The Type I PCS is maintained in a state of “hot standby” so that power can be delivered within about one cycle. Accordingly, energy losses to maintain this state of readiness are incurred at a rate of 2% of rated power. For applications requiring a full outage such as LPQ, the PCS may be equipped with a static switch.
- Type II PCS, Programmed Continuous, may be employed for applications that require the scheduled delivery of power with advanced notice of at least 10 minutes (e.g., RC, SR and

[8] With the exception of CAES, all of the energy storage media addressed herein employ electronic power conversion systems. As described in Chapter 15, CAES systems use mechanical equipment to compress air (store energy) and expand the compressed air through natural gas-fired combustion turbines (discharge energy). Consequently, normalization of CAES and electronic PCS costs has not been attempted.

LS applications), plus require control of real and reactive power during the discharge interval. Type II PCS may be turned off between scheduled discharge intervals, thus avoiding standby losses.

- Type III PCS, Prompt Discontinuous, may be used for applications that must respond within 20 milliseconds and provide control of real power for durations less than 30 seconds (discontinuous rating), e.g., SPQ applications. As discussed later, Type III PCS exploit the short duration power capability of low voltage IGBT-based PCS, and the term "pulse factor" (P_f) is introduced as the ratio of short duration to continuous power rating. The Type III PCS may be attractive for energy storage media with DC bus voltages less than 1000 V and which experience a relatively wide voltage windows. Like Type I PCS, Type III is maintained in a state of "hot standby" so that power can be delivered within the requisite time interval, and the associated energy losses are incurred during the standby period. Type III may be economic in combined applications such as SPQ and LS in which infrequent, short duration, SPQ events are mitigated at a high power level, coincident with scheduled LS events delivered at the continuous power rating. Type III PCS can deliver VAR support at the continuous power rating.

Table 5-2
PCS Type Designation

	Type	**I**	**II**	**III**
PCS Designation	**Name**	Prompt Continuous	Programmed Continuous	Prompt Discontinuous
	Topology	Voltage Sourced Inverter, 4 Quadrant Control		
	ESS Interface*	Optional DC Chopper Included as Required by ESS		Direct to ESS (No Chopper)
	Technology	GTO, IGCT, high or low voltage IGBT		Low voltage IGBT
Duty Cycle	**Response Time**	< 20 msec	≤10 min	< 20 msec
	Discharge Duration	Continuous at Rated Power		< 30 sec at Rated Power, Continuous at $1/P_f$**% Rated Power
Performance Parameters	**Conversion Efficiency**	95% during charging 95% during discharging		
	Standby Efficiency	98% (2% loss during hot standby)	100% (shut-off [0% loss] during standby)	98% (2% loss during hot standby)
	VAR Support	Continuous at Rated Power	None	Continuous at $1/P_f$*% Rated Power

* If required by the technology, Types I and II PCS may include a DC chopper
**P_f : "pulse factor", ratio of short duration to continuous power (see text)

All three PCS types are assumed to be functionally equivalent to STATCOM-type (static shunt compensator used in electrical systems) with energy storage. The topology of a STATCOM is illustrated in Figure 5-1.

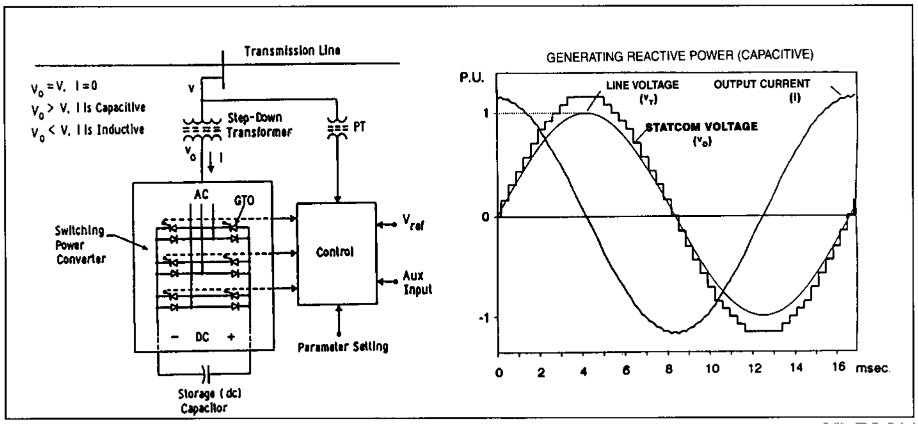

Figure 5-1
Topology of a Static Compensator (STATCOM)

A voltage source inverter synthesizes three-phase AC-voltages, converting the DC-power of an energy storage device (e.g., a battery), to the AC-power of the utility grid. Additionally, the voltage source inverter can generate or consume reactive power similar to a rotating condenser connected to the AC-grid. Closed loop controllers coordinate the power flow between the energy storage medium and the grid, as well as the reactive power flow to the grid. Figure 5-2 shows a voltage source inverter in a SMES application. In this case, a DC-DC chopper is used to convert the constant DC link voltage into a variable DC voltage across the SMES coil, thus controlling the DC-current charge/discharge rate in the large inductance of the magnet. The power is then proportional to the net DC current flowing between the DC-DC chopper and the DC link.

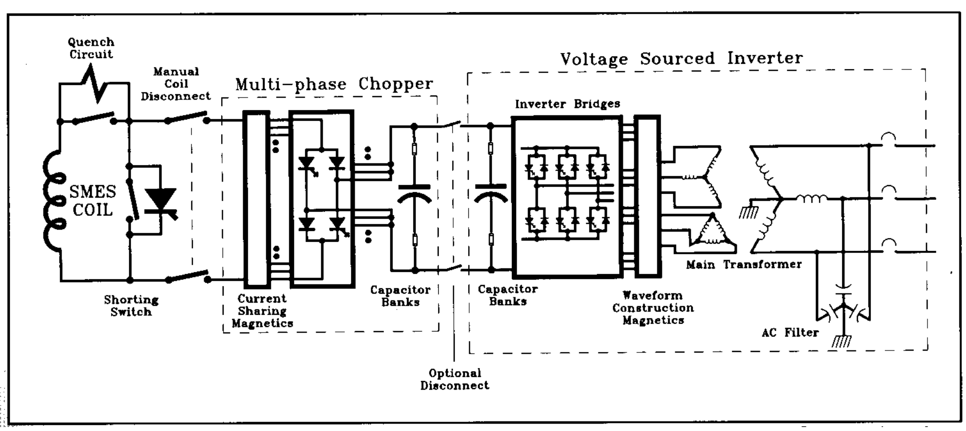

Figure 5-2
Energy Storage Interface With a Voltage Sourced Inverter

The basis for Type I PCS capital costs is derived from a representative installed cost for a 10 MW_{ac} STATCOM of $150/kW (or $150/kVA), based on mature, volume production prices projected for 2006. This value was obtained from industry sources as representative of a STATCOM configured to provide reactive power (i.e., without additional energy storage to supply real power) for a DC bus voltage window (range from maximum charge to minimum discharge) of 4000 to 2000 V_{dc}. To accommodate the range of technologies and applications addressed in this Handbook, the following empirical relationship between PCS cost and minimum DC bus voltage has been developed from industry data over the range of relevant DC discharge voltages at the input to the PCS, i.e., from about 300 to 3000 V_{dc}:

Type I PCS Cost, $/kW = $13{,}500 \cdot V_{min}^{-0.59}$,

Where V_{min} is the lowest voltage reached during continuous discharge, corresponding to the maximum current required of the power conversion system. This relationship includes allowances for shipping, exterior enclosures, installation and commissioning. (This relationship does not include BOP costs associated with supplying power to the point of common coupling, transformer, breaker/switch, land, access, permitting, etc., as described in the section titled, Functional Requirements and Costs for the Balance of Plant.)

Type II PCS costs, which do not require prompt response, are taken as 85% of Type I costs, based on experience and estimate comparisons:

Type II PCS Cost, $/kW = $11{,}500 \cdot V_{min}^{-0.59}$,

Type III PCS costs exploit the short duration power capability, as well as the relatively low cost, of the low voltage IGBT-based converters. Type III PCSs are appropriate for energy storage technologies that require large voltage windows to economically deliver infrequent, short duration power pulses such as required for SPQ applications. This approach takes advantage of the capability of low voltage IGBT-based systems to accommodate significant overloads for up to about 30 seconds. High voltage converters with GTOs, IGCTs, (and some high voltage-IGBTs) have traditionally been designed with a small over-current margin in order to utilize these more expensive devices as efficiently much as possible. Consequently, the switching frequency had to be rather low to cope with the switching losses. In contrast, low voltage converters use relatively inexpensive low voltage-IGBTs and accommodate switching losses with increased design margin. Short duration overload capability is more an issue of converter cost optimization than one of device properties. A commercial precedent exists for this approach applied to a battery energy storage system with a voltage window of approximately 800 to 300 V_{dc}. The following empirical relationship has been developed from vendor cost data:

Type III PCS Cost, $/kW = $365 \cdot P_f^{-0.54}$,

Where P_f is the "pulse factor", defined as the ratio of short duration to continuous power rating. This relationship is appropriate for P_f values from 2 to 5.

The foregoing cost algorithms for electronic PCS are based on empirical cost data compiled from multiple projects where vendors have selected semiconductor devices (IGBT, GTO, IGCT, etc.)

appropriate for the voltage and power class of the application. For the purposes of this Handbook, they provide an adequate means of quantifying relative economics and providing insight to the various energy storage technologies addressed herein.

Table 5-3 provides a summary of the bases for PCS selection and costs used in the application assessments presented within the respective energy storage technology chapters, where fixed, levelized O&M costs for PCS are included at $2/kW-year and unit weight and space are valued on the basis 22 lb/kW (10 kg/kW) and 0.13 ft^2/kW (0.012 m^2/kW).

As a guide to the Handbook user who is interested in larger (or smaller) applications than the reference 10MW_{ac} power level that employ Type I or Type II PCS at V_{min} greater than 2000 $V_{dc,}$, the following economy of scale relationship is offered:

Alternate Size Type I PCS Cost, $/kW = $300*P^{-0.3}$ or

Alternate Size Type II PCS Cost, $/kW = $255*P^{-0.3}$

Where P is the desired power level expressed in megawatts. This relationship is based on prior EPRI work and deemed applicable over a range of 1 to 50 MW_{ac} for configurations with single smaller or larger inverter. If a modular (multiple parallel) inverter design is used, costs should be based on the module size, and a 5% learning type factor applied for economies of multiplicity.

Functional Requirements and Costs for the Balance of Plant

Balance of plant (BOP) scope and cost components vary widely by site, application and technology. As a cautionary note, experience has shown that the cost of PCS and ESS system integration for pre-commercial systems is often under estimated. Accordingly, a value of $100/kW has been included for systems that have not been offered commercially as integrated systems, versus a value of $50/kW for fully integrated systems.[9] Other BOP cost components include usual owner's costs such as project engineering and construction management, grid connection, land, access, procurement and permitting. Grid connection costs include any transformers, breakers/switches, and extension of power lines needed to establish the transmission or distribution system interface with the PCS at 13.8 KV.

The space for the installation is valued at $20, $60 and $100 per square foot for exterior space with foundations, enclosed space, and enclosed space with environmental control, respectively. Enclosures and buildings are adequate to maintain equipment within typical vendor approved operating environments, defined herein as an outdoor temperature range of -30 to +50 degrees Centigrade, relative humidity ranging from 10% to 95%, and air quality free of salt air spray and corrosive gases. In addition, the enclosures and buildings attenuate audible noise to less than 65dB at 10 meters and comply with Seismic Zone III as defined by the Uniform Building Code. BOP cost data elements are summarized in Table 5-4.

[9] As the industry matures and ESS and PCS vendors team to offer fully integrated systems, this cost differential is expected to be reflected in commercial system prices as opposed to BOP costs.

Table 5-3
Summary of PCS Cost and Voltage Windows by Technology and Application

Category			No	Application	PCS Selection Bases Events: Priority Application	Response Time	Frequency	Event Duration	VAR Support	PCS Cost Bases: PCS Type	Capital, $/kW	Operating
Grid Stabilization (GS)			A	Angular Instability (GAS)	GAS	<20msec	20 cycles/event, 10 events/yr, 1 event/d	1 sec	Secondary	I or III	$13,500*V_{min}^{-0.59}$, or $365*P_f^{-0.54}$	Include standby losses
			B	Voltage Instability (GVS)	GVS		10 events/yr, 1 event/d	1 sec	Priority	I	$13,500*V_{min}^{-0.59}$	
			C	Frequency Support (GFS)	GFS		10 events/yr, 1 event/d	15 min	Secondary	I	$13,500*V_{min}^{-0.59}$	
Grid Operational Support (GOS)			D	Regulation Control (RC)	RC	≤10min	1 to 20 cycles/hr (2 cycles/hr)	7.5 min		II	$11,500*Vmin^{-0.59}$	No standby
			E	Cnvntnl Spinning Reserve (SR)	SR		10 events/yr, (10 events/yr, 1 event/d)	2 hr		II	$11,500*Vmin^{-0.59}$	
Distribution Power Quality (PQ)			F	Short Duration PQ (SPQ)	SPQ	<20msec	100 events/yr, 5 events/d, 1 event/hr	5 sec		I or III	$13,500*V_{min}^{-0.59}$, or $365*P_f^{-0.54}$	Include standby losses
			G	Long Duration PQ (LPQ)	LPQ		1 event/yr	4 hr		I	$13,500*V_{min}^{-0.59}$ + $50/kW for static switch	
Load-Shifting (LS)			H	3 hr (LS3)	LS3	≤10min	60d/yr	3 hr		II	$11,500*Vmin^{-0.59}$	No standby
			I	10 hr (LS10)	LS10		250d/yr	10 hr		II	$11,500*Vmin^{-0.59}$	
Combined Applications	"T" Utility	GFS+	C1	GAS+ GVS+ RC	GFS	<20msec	Combined per above		Priority (GVS)	I	$13,500*V_{min}^{-0.59}$	Include standby losses
	"D" Utility	SPQ +	C2	LS10 + RC + SR	SPQ				Secondary	I or III	$13,500*V_{min}^{-0.59}$, or $365*P_f^{-0.54}$	
		SPQ +	C3	LS3 + RC + SR	SPQ					I or III	$13,500*V_{min}^{-0.59}$, or $365*P_f^{-0.54}$	
		LPQ +	C4	LS3 + RC + SR	LPQ					I	$13,500*V_{min}^{-0.59}$ + $50/kW for static switch	
	"T" or "D"	LS10 +	C5	RC + SR	LS10	≤10min				II	$11,500*Vmin^{-0.59}$	No standby

Table 5-4
BOP Cost Parameters

Owner's Costs & System Integration, $/kW (Note 1)	50 or 100
Exterior Space, $/ft^2 ($/m^2) (including foundation)	20 (215)
Interior Space, $/ft^2 ($/m^2) (Note 2)	60 (646)
Interior Space w HVAC, $/ft^2 ($/m^2) (Note 2)	100 (1076)
Shipping Cost, $/100lb ($/100kg)	20 (44)

Notes:
1. $50/kW for fully integrated commercial systems; $100/kW for systems requiring PCS/ESS integration,
2. For multi-story building space, unit costs are increased by 20%

6
LEAD-ACID BATTERIES

Introduction

Lead-acid batteries are the prevalent electrical energy storage system in use today. They have a commercial history of well over a century, and are applied in every area of the industrial economy, including portable electronics, power tools, transportation, materials handling, telecommunication, emergency power, and auxiliary power in stationary power plants. In 1999, the annual sales value for lead-acid batteries was about $15B at manufacturers' levels and between $30B and $45B at retail levels, constituting between 40-45% of the sales value of all batteries in the world [1].

Because of their low cost and ready availability, lead-acid batteries have come to be accepted as the default choice for energy storage in new applications. This popularity comes despite many perceived disadvantages, including low specific energy (W-h/kg) and specific power (W/kg), short cycle life, high maintenance requirements, and environmental hazards associated with lead and sulfuric acid. Continuous improvements in chemistry, mechanical and electrical design, and operational and manufacturing techniques have mitigated many of these disadvantages, and lead-acid remains the most popular energy storage system for most large-scale applications.

Batteries using sulfuric acid as electrolyte were discussed as early as 1836 [1]. The first practical lead-acid battery was developed by Gaston Planté, who began experiments in 1859 towards development of a commercial storage battery. Planté rolled up two strips of lead sheet with a strip of linen between them. He then immersed the assembly in sulfuric acid in a glass container and applied a voltage to charge the plates. Planté found that the plates changed color as a charge was applied, indicating that a chemical reaction was taking place. Additionally, the couple was also able to deliver current in the opposite direction of the charging current. By repeatedly charging and discharging the cell, Planté found that he could increase the capacity of the cell, as corrosion of the lead increased the surface area of the plates [2, 3]. By the 1870s, Planté's invention was being used in the new central electrical plants of the day, to provide load-leveling and peaking services [1].

In 1881, Emile Alphonse Faure put forward the idea that the active material could be produced by other means and placed on a supporting foil. While a certain amount of electrical cycling was still necessary to ensure that the active material was properly retained on the foil, Faure's method significantly reduced the number of cycles required, significantly reducing the production cost and time. Pasted electrodes also had superior capacity characteristics to those produced by Planté's methods, although the Planté electrode had a longer life [2]. Other inventors quickly improved upon Faure's methods, substituting cast lead grids in the place of foil. Lead-antimony alloy grids, which were stronger than pure lead, appeared soon after.

Designs which follow Faure's model, in which the active material paste is placed on a flat supportive structure, are called flat-plate designs. Another form of pasted electrode, the tubular electrode, emerged in the 1890's. In this design, a number of needle-like parallel current conductors are surrounded by the pasted active material, which is in turn contained by a tube porous to the electrolyte. Most lead-acid batteries today use one of these two types of electrodes. The original Planté design also continues to find use in a few niche applications, especially stationary batteries.

By the early 20th century, a significant lead-acid battery manufacturing infrastructure was in place. In the first decade of the century, the batteries found use in the embryonic automobile market as prime movers for electric vehicles, though this application faded as gasoline internal combustion engines became the favored prime movers for vehicles. The technology re-entered the automotive market in the 1920s when it was widely adopted by automobile manufacturers for starting batteries. In the meantime, lead-acid batteries were already used widely in the utility industry as standby power systems in substations and power plants [4]. Other storage battery technologies such as nickel-iron were applied in niche markets, but the lead-acid battery remained the secondary battery chemistry *par excellence* until the introduction of sintered-plate nickel-cadmium batteries in the 1950s.

In the meantime, innovation with lead-acid batteries continued. Low-antimony and lead-calcium grids were introduced in the 1930s, allowing batteries requiring less frequent watering than those with conventional lead-antimony grids. Rapid progress was made in the 1970s, with the introduction of sealed lead-acid (SLA) technologies, including spiral-wound lead-acid and valve-regulated lead-acid (VRLA). The sealed technologies, in theory, required no maintenance, and enabled a number of new applications such as uninterrupted power supplies [1].

Lead-acid battery technology continues to dominate the secondary battery market to the present day. Through the years, application areas for the technology have steadily expanded into a variety of markets, including transportation (both as primary and auxiliary power sources), materials handling (such as forklifts), industrial and utility controls power, military systems power, and commercial uninterrupted power supplies, remote power. Vehicle starting continues to be the largest application of lead-acid batteries.

Research into the technology continues at present, and has resulted in improvements in lead-acid design, manufacturing, recycling, active materials, and packaging materials. In many cases, performance improvements have allowed lead-acid products to overtake and replace erstwhile competitors. This improved performance continues even as costs continue to fall in real terms. A Starting, Lighting and Ignition (SLI) battery in 1924 cost about $70; today, in 2003, it still cost $70, though the price of the automobile has increased by a factor of 20 or more [4].

In the utility sector, flooded stationary lead-acid batteries made up the largest part of the market until the introduction of VRLA batteries in the mid 1970s. VRLA batteries were expected to take much of the utility market because of their lower initial cost and maintenance requirement, but have since been found to have shorter service life than flooded batteries, requiring more frequent replacement. Due to this life issue and other operational issues, many utilities have returned to flooded batteries, although VRLA batteries continue to compete in this market.

Description

Types of Lead-Acid Batteries

Lead-acid batteries come in several types, each suited for specific applications. Although all types of lead-acid batteries follow the same basic chemical reaction, they can vary widely in terms of cost, method of manufacture, and performance.

There are two main categories of lead-acid batteries: Flooded or vented types, in which the electrodes are immersed in reservoirs of excess liquid electrolyte; and sealed or valve-regulated types, in which electrolyte is immobilized in an absorbent separator or in a gel. These two types are significantly different in terms of design, manufacturing, operating characteristics, life expectancy, and cost. Within these two categories, there are several sub-types of batteries, each optimized to fit a particular set of applications.

It should also be noted that both flooded and valve-regulated lead-acid batteries can also be categorized by the grid alloys used in the electrodes. These alloys will be described at the end of this section.

Flooded Lead-Acid Batteries

Flooded lead-acid batteries, sometimes called vented lead-acid (VLA) batteries, are the traditional form of lead-acid batteries and continue to form the bulk of the market, due to their use in automobiles and in most industrial applications. There are three general types of flooded lead-acid batteries: starting, lighting and ignition batteries, deep-cycle or traction batteries, and stationary batteries.

Starting, Lighting, and Ignition (SLI) Batteries

SLI batteries are the most familiar type of lead-acid batteries. They acquire their name from their most common use, starting and auxiliary power for internal combustion engine systems (which leads to their name). These batteries are designed to be as inexpensive as possible, and are usually designed in the flat-plate configuration using lead-antimony or lead-calcium grids. The SLI design provides good current capability at low cost but with relatively low cycle life at deep cycles. It is best suited for shallow-cycle applications which require a large current for short periods of time, such as vehicle cranking. SLI batteries are well suited for short-term utility power quality applications.

Older forms of SLI batteries were vented and required the regular addition of water to offset water loss due to gassing. Modern maintenance-free SLI batteries are designed with low-antimony or lead-calcium alloys to minimize water loss and do not require such care.

Deep-Cycle/Traction Batteries

In contrast to SLI batteries, deep-cycle batteries are designed for deep discharge applications. They are most commonly used in forklifts, golf carts, and other electrically powered vehicles, hence the appellation “traction batteries.”

The construction of deep-cycle batteries differs from that of SLI batteries in several ways. The plates, particularly the positive plates, are made thicker and sturdier, and are made with grids with higher antimony content, necessitating a larger electrolyte reservoir to reduce water addition. In many cases, tubular or gauntlet type positives are used to reduce deterioration of the positive electrodes.

Stationary Batteries

Stationary batteries are generally used to provide dc power for controls and switching operation, as well as standby emergency power, in utility substations, power generation plants, and telecommunications systems. For the most part, these batteries operate under “float-charge” – a charger keeps them at the full charge voltage with a small charging current, so that they are ready to be used when ready. The battery experiences occasional discharges when a relay, breaker or motor is energized, and during outages. In this application, energy and power density are of secondary importance to long life and low maintenance. Partly for these reasons, stationary batteries have seen comparatively little development since their introduction in the early twentieth-century.

The construction of these batteries tends to be very conservative. Very thick Planté positive electrodes, sometimes of pure lead, are commonly used, although pasted plate and tubular positive electrodes are also common. Negative electrodes are usually pasted plate. The care used in construction is reflected in their extremely long service life, often extending to 30 to 40 years. The water lost to electrolysis during long periods of float charge must be replaced by regular watering. The batteries contain large electrolyte reservoirs with a quantity of excess electrolyte to extend the interval between such maintenance operations.

Figure 6-1
A Flooded Stationary Lead-Acid Cell *(Courtesy C&D Technologies, Inc.)*

Valve Regulated Lead-Acid (VRLA) Batteries

The excess of electrolyte in flooded lead-acid batteries is sometimes an issue, especially when it comes to electrolyte leakage. For this reason, batteries without a large excess of electrolyte, called *starved-electrolyte batteries*, were devised. Starved-electrolyte batteries must be partially sealed so that electrolyte is not lost through evaporation or gassing during charge. This design feature has led to their designation as sealed lead-acid (SLA) batteries.

The batteries are rarely hermetically sealed, however; the packaging often has some permeability to hydrogen, and in any event a hermetically sealed package would be dangerous in the event of pressure buildup inside the cell. In most cases, a pressure release valve is used to limit movement of gas into and out of the cell. For this reason, these batteries are better described as VRLA batteries.

In the past, the term VRLA has been applied specifically to prismatic designs with low venting pressures, in contrast to cylindrical designs with higher venting pressures, which have been called cylindrical SLA batteries. Most developers and manufacturers use the terms VRLA and SLA interchangeably, however. Throughout this text, the more accurate VRLA will be used for the purpose of clarity. Where a distinction must be made, the two types will be differentiated by the terms prismatic and cylindrical.

VRLA batteries are also often referred to as being maintenance-free. This is true only insofar as there is no requirement to water these batteries. Other maintenance, such as tightening of terminals and checking of auxiliary systems such as hydrogen sensors, must be performed on VRLA batteries as well as flooded batteries.

Because of their starved electrolyte design, VRLA batteries must be constructed and operated quite differently from flooded designs. The electrolyte is contained within an absorbent separator or a gel to prevent migration out of the cell. Charging and heat generation must be carefully managed to minimize water loss through electrolysis. Designs usually incorporate some method through which hydrogen and oxygen generated during charge are encouraged to recombine within the cell, further reducing the loss of water. Despite these measures, VRLA batteries typically have shorter service life than conventional flooded lead-acid designs.

VRLA batteries have found application in a large number of small applications, including portable electronics, power tools, and uninterrupted power supplies (UPS), and in a few large applications such as forklift batteries. They have had limited success in supplanting conventional flooded lead-acid batteries in many industrial applications because of their shorter service life and intolerance of abuse. They have been more successful in replacing other, more expensive battery chemistries such as nickel-cadmium and nickel-iron in specialized industrial applications.

VRLA batteries come in two major types, depending on how the electrolyte is immobilized. In *absorbed glass mat (AGM)* VRLA batteries, the electrolyte is held within a highly porous, absorbent separator which acts as a reservoir. This separator is most commonly composed of microglass fibers. In *gelled electrolyte* VRLA batteries (often known as *gel cells*), a gelling agent such as fused silica is added to the electrolyte, causing it to harden into a gel. The gelling agent reacts chemically with the electrolyte, so that the immobilization is as much chemical as physical [1].

VRLA batteries come in both prismatic and cylindrical designs. Prismatic designs contain flat electrodes in a rectangular box, and come in both AGM and gelled electrolyte types. Cylindrical cells are almost always AGM types, and are composed of spiral-wound electrodes in a cylindrical container. Cylindrical designs are structurally capable of withstanding higher internal pressures, and so are designed to vent at between 25 to 40 psig. Prismatic designs must vent at lower pressures, usually around 2 to 5 psig.

In theory, electrolyte immobilization allows operation in any orientation without danger of electrolyte spillage. This is an important consideration in many application areas, particularly portable electronics and power tools. In practice, however, there have been problems in operating VRLA batteries in orientations which put stress on the seals, leading to greater-than-expected water leakage. This is especially true of stationary VRLA batteries stacked horizontally [18].

VRLA batteries were expected to largely replace conventional flooded technologies in long-term applications, much as the maintenance-free SLI replaced vented SLI batteries. The initial life expectancy for VRLA batteries was estimated at between 10 and 20 years. A number of embarrassing failures demonstrated that the VRLA batteries did not meet this requirement. In one often-quoted study of almost 25,000 VRLA cells, the failure rates ranged from 27% to 86%, depending on manufacturer, after only 3 to 7 years of use. For the entire sample, the average failure rate was 64% [16].

It is has since become evident that VRLA batteries have shorter life than their flooded equivalents. While the reasons for this are not entirely clear, the principal cause for shorter life seems to be that the VRLA battery has a much narrower band of normal operation than conventional flooded lead-acid batteries. The VRLA cell is much more sensitive to temperature variations, is much less tolerant of overcharge or overdischarge, and requires float charging in a very narrow voltage range. Since operation outside this narrow operating window is more likely for VRLA batteries, they are more likely to degrade. This is especially true of large batteries, in which individual cells are likely to operate under slightly different conditions, especially during float charge.

Furthermore, the starved-electrolyte nature of the VRLA cell makes it more sensitive to corrosion and water loss common to all lead-acid cells. The recombination process, which produces heat inside the VRLA cell, makes the cells prone to overheating, especially during float-charging operation.

These problems have made VRLA batteries less attractive in recent years. Despite these problems, VRLA batteries continue to have significant advantages over flooded batteries, and will continue to be used in some applications. In addition, developers continue to improve the design, manufacturing, and operating techniques associated with VRLA batteries, and the life issues are likely to improve with time.

Electrode Grid Types: Lead-Antimony and Lead-Calcium

Pure lead is too soft for use in electrode grids. For this reason, the lead in the grid is usually alloyed with another substance to give it structural strength. The nature of the alloying material has significant effects on the performance of the battery. For this reason, the type of alloying material is often used in the description of the battery.

The most common alloying materials used today are antimony and calcium. Lead-antimony electrodes are generally stronger, and perform better under deep-cycling conditions. Lead-antimony designs are prone to gassing, and so require the frequent addition of water. They also draw more current during float charge. The so-called low-antimony designs use grids with lower concentrations of antimony, and so are less susceptible to gassing but have shorter life under deep-cycling conditions than electrodes with higher antimony concentrations.

Lead-calcium designs were produced to reduce gassing at the electrodes, and are therefore more effective at preventing water loss. The calcium promotes corrosion in the positive electrode, however, especially during repeated cycling. This corrosion seriously shortens the life of the battery, and can cause unexpected failure.

The choice of electrode materials is heavily dependent on the application. In general, lead-antimony batteries are used in applications where deep-cycling is common, and regular maintenance is possible. In applications in which deep-cycling is not common, and regular maintenance is less preferable than more frequent replacement, lead-calcium batteries are used.

There are other materials that are sometimes used in lead electrodes. Most prominent are tin and selenium. The effects of these other materials are described below.

Description of the Technology

General Features and Limitations of Lead-Acid Battery Technology

There are many common complaints about lead-acid battery technology. The most common are that it has poor energy density, short cycle life, requires a great deal of maintenance, and contains toxic materials. Almost any other energy storage system is superior to lead-acid in these areas.

Despite these criticisms, the fact remains that lead-acid batteries are still the most cost-effective electrical energy storage technology known, as well as the most mature and best understood. These advantages make lead-acid the natural default choice for energy storage in most applications where a rechargeable system is required.

Chemistry

Electrode Reactions

All lead-acid designs share the same basic chemistry. The positive electrode is composed of lead-dioxide, PbO_2, while the negative electrode is composed of metallic lead, Pb. The active material in both electrodes is highly porous to maximize surface area. The electrolyte is a sulfuric acid solution, usually around 37% sulfuric acid by weight when the battery is fully charged. The reaction product on both sides is lead sulfate, $PbSO_4$.

The half cell reactions are as follows:

Positive: $$PbO_2 + 3H^+ + HSO_4^- + 2e^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} PbSO_4 + 2H_2O \qquad \textbf{Eq. 6-1}$$

Negative: $$Pb + HSO_4^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} PbSO_4 + H^+ + 2e^- \qquad \textbf{Eq. 6-2}$$

The overall reaction is:

Overall: $$PbO_2 + Pb + 2H_2SO_4 \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} 2PbSO_4 + 2H_2O \qquad \textbf{Eq. 6-3}$$

A notable aspect of this system is that sulfuric acid is consumed during the discharge reaction, so that the concentration of the electrolyte changes as the battery is discharged. This means that the state-of-charge of a lead-acid battery can be determined by measuring the concentration of the electrolyte, usually through a specific gravity measurement. The range of specific gravity measurement from charge to discharge is dependent on the design of the battery and the locale for which it is designed. In batteries designed for temperate climes, the electrolyte specific gravity is usually between 1.2 and 1.3 in a fully charged state and between 1.0 and 1.2 in a fully discharged state.

The end of discharge occurs when the active material on either of the two electrodes is depleted, or when the concentration of sulfuric acid in the electrolyte is too small to maintain a reaction.

Charging and Gassing

The charge reactions proceed in the opposite direction to the discharge reactions. The voltage of the cell rises as it is charged. When a certain voltage is reached, a competing water electrolysis reaction begins, causing hydrogen evolution on the negative electrode and oxygen evolution on the positive. This phenomenon is known as "gassing." The voltage at which gassing begins is called the gassing voltage, and is around 2.39 V_{dc}/cell for most lead-acid designs. As the voltage increases, a larger and larger part of the energy input goes towards electrolysis, so that the charge efficiency of the cell shrinks. The cell is considered fully charged when all of the current goes towards electrolysis (i.e. the charge efficiency is zero).

Flooded batteries and VRLA batteries deal with gassing differently. In flooded batteries, the hydrogen and oxygen are allowed to escape into the environment. A port is built into each cell to allow the addition of water at regular intervals to replace the water lost. Some cells, such as maintenance-free flooded cells, contain catalysts to encourage the hydrogen and oxygen to recombine within the cell, reducing the rate of water loss. These designs contain sufficient electrolyte to last the life of the battery.

In VRLA batteries, oxygen produced on the positive electrode migrates to the negative electrode through pores in the separator and recombines with hydrogen there to return to the electrolyte as water. In addition to allowing the cell to retain water, the oxygen migration also reduces the amount of hydrogen evolved on the negative electrode. The small quantity of hydrogen that does evolve often leaves the cell before it can recombine, either through the vent or through the walls of the cell.

If elements such as antimony or arsenic are present in the electrodes, even in small quantities, gassing can result in the production of small quantities of toxic gases such as stibine or arsine. A lead-acid battery system must be designed to ensure that these gases are properly vented and do not accumulate in an area where they present a health hazard to personnel.

Grid Alloys

The grids used in both electrodes are composed of lead mixed with another metal to improve mechanical strength. The most common alloying materials are antimony and calcium, although others are used and new combinations are always under investigation.

Antimony was the earliest alloying material extensively used in lead grids, and is still used extensively today. The amount of antimony determines the strength of the grid; heavier antimony concentrations lead to stronger plates. This is particularly important in the positive electrode, which requires the strength to inhibit the effects of corrosion and active material shedding in deep-cycle applications. Antimony also prevents the formation of a barrier layer between the positive active material and the grid during deep-cycling. Grids in modern deep-cycle batteries contain between 4% to 6% antimony [1].

Antimony promotes self-discharge, however, particularly on the negative electrode, where it promotes the production of hydrogen during overcharge. For this reason, antimony concentrations are usually kept as low as possible without compromising the cycling capability of the cell. Low-antimony designs use concentrations between 1.5% and 2% [1]. Occasionally, the negative electrode grid is made entirely without antimony. As the battery ages, however, antimony from the positive electrode gradually migrates to the negative electrode, so that the gassing gradually increases with time.

Lead-calcium grids were found to strengthen grids while reducing gassing. For this reason, lead-calcium grids were used to create low-maintenance and maintenance-free lead-acid batteries, which do not require water addition.

In the positive electrode, however, calcium promotes corrosion, which quickly leads to failure due to plate expansion. To mitigate the corrosion effects, a lead-calcium-tin alloy, or simply a lead-tin alloy, is sometimes used. This increases the cost of the battery but lengthens the service life.

Ideally, a battery would have the low-corrosion, deep-cycle abilities of lead-antimony along with the low-gassing effects of lead-calcium. This can be done with a hybrid design with a low-antimony grid in the positive electrode and a lead-calcium grid in the negative electrode. This design is, in fact, used in most maintenance-free SLI batteries.

So-called lead-selenium grids are actually low-antimony grids that include a small quantity of selenium. These grids produce characteristics somewhere between lead-antimony and lead-calcium grids. While these and other materials continue to be researched extensively, they are not yet popular in manufacturing except in specialized applications.

Performance Characteristics

Discharge and Charge Voltage

The lead-acid cell has a nominal voltage of 2 V_{dc}. The true voltage is a complex function of state-of-charge, electrode composition, electrolyte concentration, temperature, current rate, and other variables. The open-circuit voltage usually ranges between 1.90 V_{dc} and 2.15 V_{dc}. A typical cell operates between 1.75 V_{dc} at end of discharge, to 2.5 V_{dc} at end of charge. These numbers are hardly fixed; in particular, much lower voltages may result during high-rate discharges at low temperature, as may be encountered when starting a car in extremely cold weather.

Figure 6-2 shows a typical discharge curve for a stationary lead-acid battery.

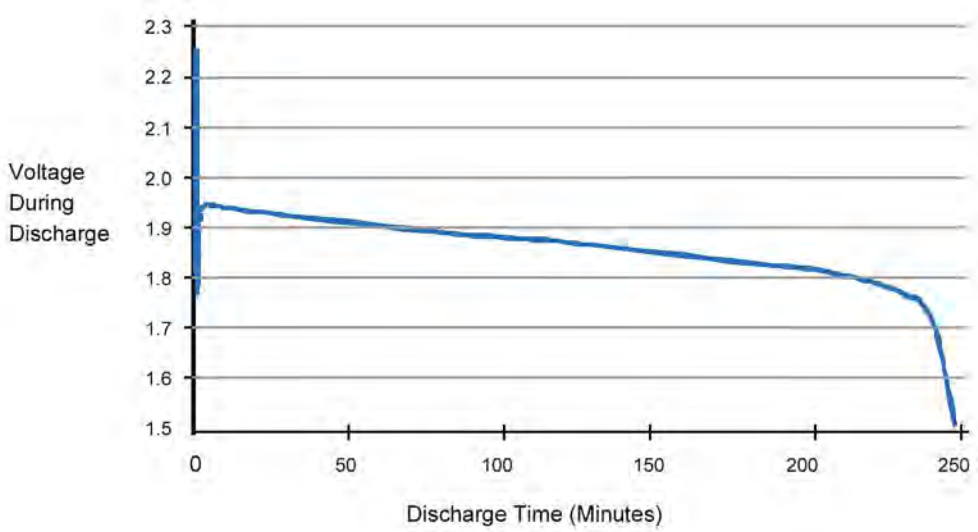

Figure 6-2
Discharge Curve for a Lead-Acid Battery [18]

Coup de Fouet

At the beginning of discharge, there is a very brief voltage dip before the voltage stabilizes at a higher plateau (see Figure 6-3). This dip is called the *coup de fouet* (French for "the crack of the whip") and is a result of the chemical mechanism on the positive plate during discharge. This phenomenon is particularly evident in batteries which have been on float charge for a significant period of time, and is particularly strong in VRLA batteries.

The coup de fouet effect is not necessarily a sign of damage or degradation of the battery, although it does tend to grow more pronounced as the battery ages. The effect should be taken into account during system design, however, as the voltage during this time may temporarily drop significantly below the cut-off voltage of the cell. In the early days of VRLA use in UPS systems, the power electronics design did not take this effect into consideration. During an initial high-rate discharge, the coup de fouet caused the voltage to drop rapidly, causing the power electronics to cut out. Subsequently, many VRLA manufacturers were forced to derate their systems to account for the effect [18].

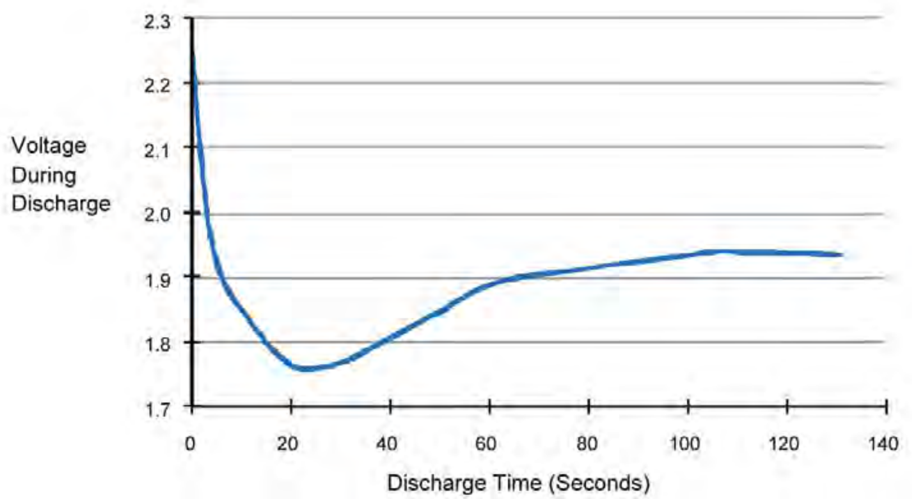

Figure 6-3
The Coup de Fouet [18]

Efficiency

The lead-acid battery is relatively efficient, thanks to its relatively high cell voltage. Round-trip efficiencies for lead-acid batteries generally range between 75% and 85% DC-to-DC.

Battery inefficiencies can be divided into coulombic and thermodynamic. Coulombic inefficiencies describe inefficiencies on a charge basis: fewer ampere-hours are discharged from the battery than are put in. These inefficiencies are the result of side reactions that consume part of the current input during charge. The most important side reaction is the electrolysis of water into hydrogen and oxygen. The energy that goes into these side reactions is lost either as heat, if the gases recombine within the cell, or with vented gases. Coulombic inefficiency varies with the design of the cell, and is particularly dependent on the type of grid alloy used: lead-antimony grids produce significantly higher coulombic inefficiencies than lead-calcium grids.

During float charge operation, current input goes entirely towards electrolysis. That is, the cell has a coulombic efficiency of 0%. The current that the battery draws during float charge is also dependent on the design, particularly the type of grid alloy employed in the cell.

Thermodynamic inefficiencies are calculated on an energy basis, and arise from a variety of sources, including internal resistance, polarization, and temperature effects. These inefficiencies are seen in the difference between charge voltage and discharge voltage for a battery cell.

The efficiencies of lead-acid battery systems must include other factors in addition to battery efficiency. PCS efficiency, parasitic loads such as HVAC and controls, and losses due to cabling and connections must also be taken into account at the system level.

Self-Discharge

Since the electrolyte is somewhat conductive, the discharge reaction will occur even in the absence of an electrical connection between the electrodes. This reaction, called the "self-discharge," occurs relatively slowly, and months will pass before the battery is discharged. In addition, discharge can occur between two parts of the same electrode, especially if the electrode is partially charged or if there are elements other than lead within the electrode. This is known as "local action" and is most common in the negative electrode, particularly if antimony is present. A float charge is applied to lead-acid batteries to counteract the effect of local action (see below).

Effects of Temperature

Temperature has strong effects on the operation of the lead-acid battery. In general, the battery is designed for optimal performance around room temperature, about 77ºF (25ºC). The capacity of batteries generally falls with decreasing temperature, as shown in Figure 6-4. This effect is a result of thermodynamic effects as well as increased resistance in the electrolyte.

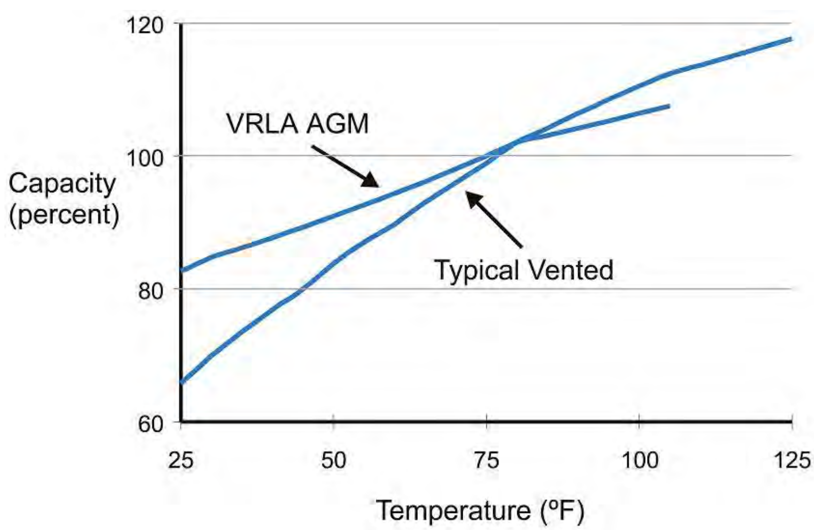

Figure 6-4
The Effect of Temperature on Capacity of Lead-Acid Batteries [18]

When the temperature falls below the freezing point of water, the discharge response of the battery becomes sluggish. At very low temperatures, below -40ºF, the electrolyte may freeze, producing an explosion hazard.

At higher temperatures, the internal resistance of the electrolyte falls and the discharge voltage increases. The gassing voltage decreases, however, and the self-discharge rate is larger. The overall result is decreased charge efficiency, which results in further heating and more rapid loss of water to gassing and evaporation. In VRLA batteries, this phenomenon sometimes results in a condition known as "thermal runaway," during which the continuously increasing temperature and falling efficiency results in a vicious cycle, often ending in venting and failure of the battery.

Sulfation

During regular discharge, lead sulfate ($PbSO_4$) precipitates on the electrode surfaces in the form of small crystals. As time passes, if the lead sulfate is not cycled, these crystals grow into larger crystals. These larger crystals are more impervious to electrolyte and are less reactive during charge. They also take up more space in the electrode, and their growth puts mechanical stress on the surrounding material. The formation of these crystals, known as *sulfation*, leads to reduced capacity of the cell in terms of both energy and power. Ultimately, it can lead to cracking and buckling in the electrode as the crystals expand, causing irreversible damage to the cell.

The prevention of sulfation is done principally through operational means. Whenever possible, the cells are kept fully charged, so that the concentration of lead sulfate is as small as possible. Batteries that are not being cycled are usually charged with a small current, which maintains the battery at a constant voltage close to the end-of-charge voltage. This operation, known as "float charge," counteracts the effects of self-discharge and is an important operating procedure for lead-acid systems.

Hydration

Where sulfation occurs when lead-acid cells are undercharged, a more serious condition known as *hydration* occurs when the battery remains at a low state of charge for long periods of time without charging at all. At very low states of charge, the lead components of the cell become highly soluble in the electrolyte, causing them to partially dissolve into lead hydrates. These compounds are then deposited in various parts of the cell, particularly separator pores. When the cell is finally charged, these hydrates once again become lead, and form a short-circuit path within the cell. The immediate results are a significantly higher charge current during float charge operation, and a greater self-discharge rate when open-circuit. In serious cases, the short-circuit condition can be strong enough to render the cell unusable.

Hydration is an irreversible process that causes permanent damage to cells, and can occur in a discharged cell in a matter of hours. For this reason, lead-acid batteries should not be left in a discharged state for any length of time [20].

Degradation

There are a number of degradation modes for lead-acid batteries. Depending on the way a battery is built, used and maintained, one of these modes usually dominates. Many, but not all, degradation modes ultimately lead to failure.

In the early stages of life, the capacity of a battery actually rises, as shown in Figure 6-5. This is a result of continuing formation of the active material, as well as the slow diffusion of electrolyte into smaller pores. Eventually, the same processes contribute to the decay of capacity by speeding corrosion.

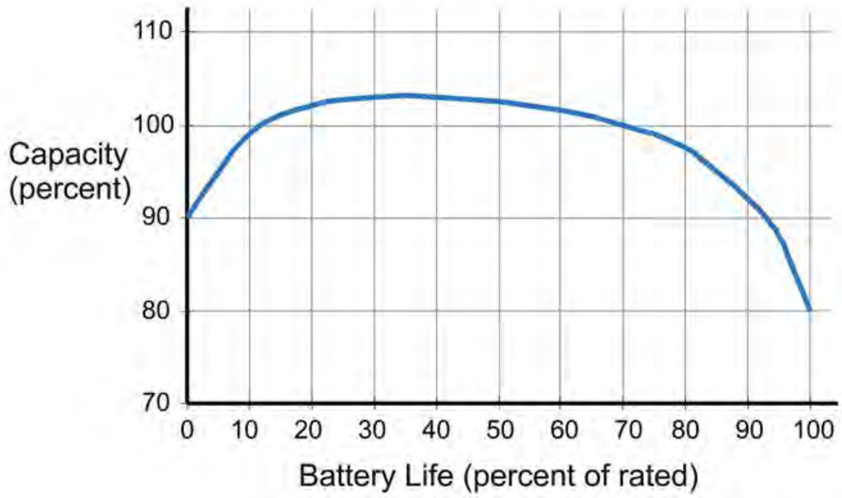

Figure 6-5
Capacity Changes Over the Life of a Battery [18]

Grid corrosion is the most common form of degradation and failure. This mode is common to all forms of lead-acid batteries, and is the dominant mode for those that do not see extreme cycling conditions, such as SLI batteries and stationary batteries. As the battery ages, the lead in the positive grid corrodes to lead oxide. This corrosion is encouraged by float charge operation. As the grid corrodes, it grows, putting mechanical stress on the electrode. This causes linkages between the grid and the active material to break and reduces paths for electrical conduction. This increases the internal resistance of the electrode and gradually decreases the power capability and the energy available for discharge.

Certain types of grids, particularly those made of lead-calcium alloy, are particularly susceptible to corrosion.

As with most batteries, lead-acid batteries gradually wear out as they are cycled. Degradation increases as the depth-of-discharge increases. This is the result of mechanical stress as the crystal structure of the electrodes change back and forth between the charged and discharged states. In addition, the active material gradually falls off the electrode as it is cycled; this is called *active material shedding*. Shedding gradually reduces the energy capacity of the cell.

Electrolyte stratification also occurs as the battery is cycled. Since sulfuric acid is a participant in the electrode reactions, during repeated cycling the acid concentration in the pores of the electrode becomes greater than that in the bulk solution. This higher-density sinks lower in the electrodes, while lower-density acid rises to the top of the electrodes. The end result is poorer charge acceptance, power capability, and ultimately shorter battery life. Stratification is a common problem for deep-cycled batteries. It is often mitigated by regularly performing an equalization charge, which also serves to equalize the charge level of the cells in a battery. In stationary batteries, the electrolyte is sometimes mechanically agitated with compressed air to minimize the effects of stratification.

Low electrolyte level causes increased internal resistance, reducing the power capability of a battery. In addition, the concentration of the electrolyte increases, promoting corrosion. As the electrolyte level drops, sections of the electrodes may become dry, meaning those sections cannot be properly charged. This leads to sulfation and corrosion of those sections, and ultimately bending and buckling of the plate, causing increased internal resistance and ultimately failure. In maintenance-free flooded and VRLA batteries, where water cannot be replaced, degradation of the battery due to water loss can occur very rapidly if the battery is improperly operated. High-temperature operation and improper charging encourage water loss from the cell and shorten the life of the battery.

Sulfation, as described above, can reduce the capacity of a cell and ultimately lead to failure. Sulfation can be prevented by ensuring that batteries are properly float charged. In flooded batteries, the proper water level should always be maintained. To prevent failure due to hydration, very deep discharges of lead-acid batteries should be avoided, and batteries should be promptly recharged after discharging.

During repeated cycling of batteries with non-antimonial grids, a barrier layer forms in the positive electrode between the active material and the grid. This layer increases the internal resistance in the cell and can also prevent deep discharge. Eventually, this causes the battery to fail. This is an important reason for the use of antimonial alloys in the positive electrode grid.

There are other degradation modes in lead-acid batteries that do not usually lead to failure, but should be taken into account. The most common of these is antimony migration in batteries with lead-antimony electrodes. Antimony in the negative electrode promotes a higher self-discharge rate through "local action," in which antimony and lead in proximity on the negative electrode form an electrochemical couple, discharging the lead. During float charge, antimony also promotes hydrogen evolution and water loss. For these reasons, many negative grids are made without antimony. As mentioned above, however, antimony produces useful properties in the positive electrode, so that lead-antimony grids are used in the positive. As the battery ages, some of this antimony is released by corrosion, and then migrates through the electrolyte to the negative electrode. The overall effect is that the float charge current and rate of water loss increase as the battery ages.

Life Expectancy

As with any electrochemical battery, the life expectancy of a lead-acid battery depends heavily on the design, manufacturing, and operation of the battery. Cycle life expectancy at 100% DOD can range from 30 to 100 for SLI batteries, up to over a thousand for some of the deep-cycle batteries.

Few manufacturers will make predictions for life on the basis of DOD, however, since life depends on other factors which are equally or more important, such as charge profile and temperature. Many manufacturers instead warranty the battery provided that a certain number of cycles is not exceeded. Figure 6-6 shows one manufacturer's warranty as a function of the rate and number of deep discharges (in excess of 80% DOD) on the battery.

Rate of Discharge	Number of Discharges Per Year	
	Calcium	Antimony
8 hr	2	8
7 hr	2	8
6 hr	2	8
5 hr	3	12
4 hr	3	12
3 hr	4	16
2 hr	4	16
1 hr	5	20
15 min	6	24
10 min	7	28
5 min	8	32

Figure 6-6
One Manufacturer's Warranty as a Function of Rate and Number of Discharges [18]

Battery manufacturers more commonly state service life expectancies in terms of years at expected usage conditions. Most SLI are rated for 5 to 7 years; deep-cycle batteries are rated from 3 to 5 years. Stationary lead-acid batteries in most utility applications are rated for very long periods, from 15 to 30 years.

VRLA batteries are presently rated for 5 to 10 years for the same stationary applications. While many VRLA battery manufacturers promise longer life, it should be noted that these life spans depend heavily on maintaining tight control on temperature and charging parameters, which can add cost to the battery system.

Operational considerations, particularly charge profile and operating temperature, heavily influence the life of a battery. Long periods of overcharge will lead to excess water loss and stress the electrodes, causing premature failure. For VRLA batteries, even mild overcharge can lead to thermal runaway and premature failure of cells.

Operating temperature is often the most important factor in the life of a battery, as shown in Figure 6-7. High operating temperature encourages gassing, evaporative water loss, and corrosion, and in VRLA cells can cause thermal runaway.

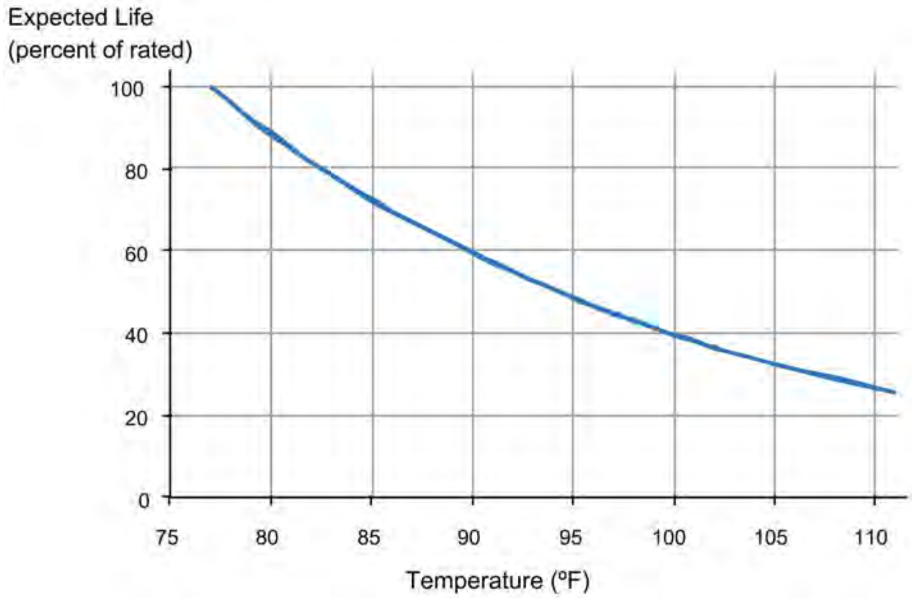

Figure 6-7
The Effect of Temperature on the Life of Lead-Acid Batteries [18]

Lead Acid Battery Construction

A lead-acid battery or cell is composed of several major components:

- A negative electrode assembly, constituted by a lead alloy grid and pure lead active material
- A positive electrode assembly, constituted by a lead alloy grid and lead-oxide active material
- A separator, which keeps the electrodes from physically touching, and in AGM-type VRLA cells contains the electrolyte
- Electrolyte, consisting of a solution of sulfuric acid in water
- Cell connectors, which connect cells electrically within a battery. At the ends of a battery, a terminal takes the place of the connector. Terminals are used to connect batteries together or to connect a battery to its load
- Packaging to contain the other components

A cross-section of a typical lead-acid cell is shown in Figure 6-8.

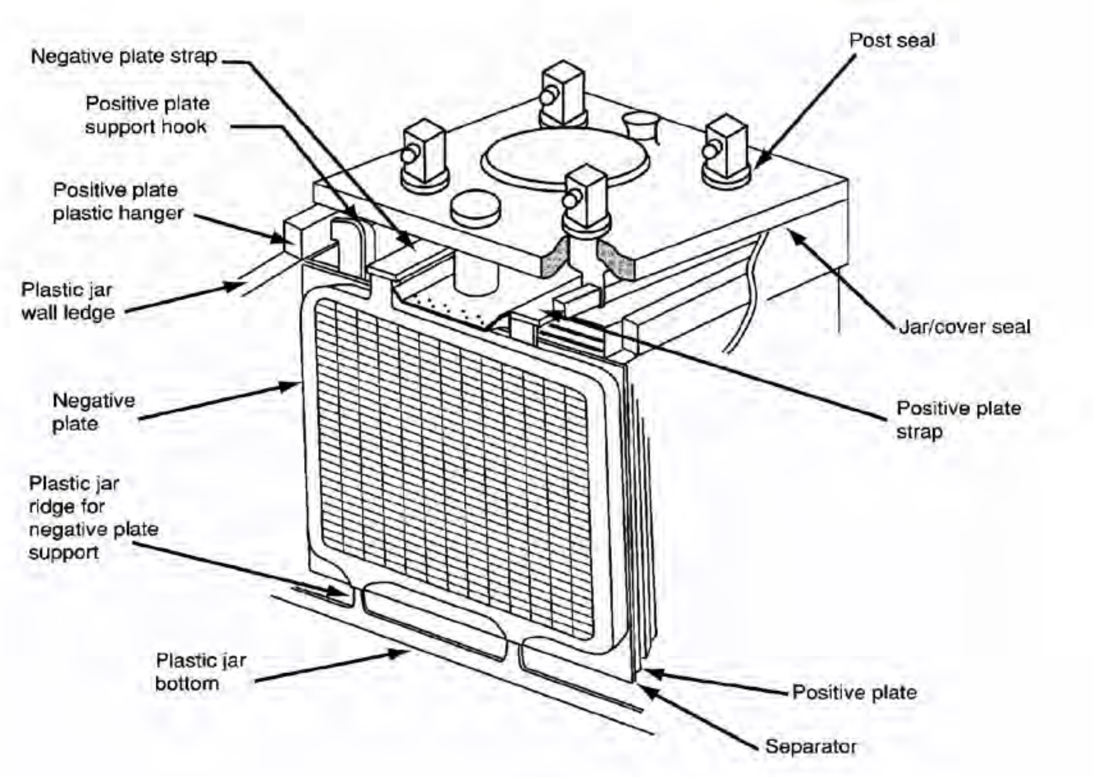

Figure 6-8
Cross-Section of a Flooded Lead-Acid Battery [18]

In many batteries, especially large stationary cells such as that shown in Figure 6-1 there are several pairs of electrodes in a cell. This allows a cell to maintain a higher current rating while retaining the manufacturing advantages of a relatively small electrode plate. These electrodes are connected in parallel rather than series.

System Design

As described above, limitations of the lead-acid chemistry restrict the voltage of a single cell to a little more than 2 V_{dc}. It is possible to produce systems with higher voltage by electrically linking cells in series. In many cases, cells are packaged together in the same case and sold as a unit. The 12 V_{dc} SLI battery, for instance, is a package containing six 2 V_{dc} lead-acid cells connected in series.

Individual cells are also limited in terms of producing discharge current at a particular voltage. This limitation can also be overcome by electrically linking cells (or series strings of cells) in parallel. In this way, systems can be designed to provide a large current at a reasonably high voltage.

As the number of cells in a system increases, the system becomes more complex and the number of points of possible failures also increases. For this reason, very high-voltage lead-acid battery systems are not practical. Past developers have generally agreed that the practical limitation on string voltage is about 2000 V_{dc}, on the basis of system complexity, safety, and ease of operation [19].

The design of batteries for stationary applications requires trade-offs between a number of factors. These batteries are usually designed to minimize floor space without compromising electrical, thermal and maintenance considerations. The cells are typically mounted on racks which allow easy accessibility to all cells for inspection, maintenance, and replacement when necessary. The assembly is housed inside a building or in a weatherproof enclosure.

Figure 6-9
Stationary Battery Installation *(Courtesy C&D Technologies)*

The cells are connected electrically using large cables or bus bars, and are arranged in a configuration so that the total length of the current path through the series string is minimized. These features ensure that the internal resistance of the system is kept as low as possible.

The design must provide a thermal path for the heat produced by the battery during charge and discharge. In most cases, active cooling such as air-conditioning is used to keep the battery cool. In locations subject to cold weather, heating systems may be required to prevent electrolyte freezing.

There must also be safety precautions for hydrogen and other gases which may be produced during charging. The battery area should always be well-ventilated, and a hydrogen sensor should be installed to detect concentrations before they reach a hazardous level. Toxic gases such as stibine and arsine, are sometimes produced from grids made from alloys of antimony and arsenic. Such alloys should not be used if the battery is to be operated in a closed environment where personnel are working.

Some manufacturers, especially those producing VRLA and maintenance-free flooded batteries, claim that hydrogen production is non-existent or negligible. It is recommended that the designer be cautious of these claims, since they have proved incorrect in more than one instance [18].

In some instances, a control system is added to the battery to ensure that it is operating normally. This system may be as simple as a monitoring system that signals abnormal conditions or may be a complex active system that controls operations to prevent problems before they occur.

Power conditioning is often used with battery systems to ensure that the output power meets quality required by the application. In dc applications in which the required voltage range is very narrow, a DC-DC converter may be used to compensate for the change in voltage over the course of discharge. An inverter is used when ac output power is required. Whenever power conditioning is used, the voltage, current, and power capabilities of the power conditioning system, as well as its input requirements, must be considered in developing the system. The system designer must also consider that thermal calculations must also include dissipation from the power electronics.

These auxiliary systems may add significant costs to the system, as well as introducing further complexity and vulnerability to failure.

Operation and Maintenance

A wide body of literature already exists on the operation and maintenance of lead-acid batteries in utility applications. Only the most common operational and maintenance considerations are listed here.

Float Charging

Float charging, in which a constant voltage is applied to a fully-charged battery to produce a small charging current, is used to counteract self-discharge in the battery. This ensures that the battery is fully charged when discharge is necessary, and inhibits sulfation.

The energy delivered in the float charge is largely dissipated as heat. Part of the energy goes towards the production of hydrogen and oxygen through electrolysis of water. The latter process is kept to a minimum through the use of low-antimony or lead-calcium plates, particularly on the negative electrode. In VRLA batteries, recombination methods are also used to minimize hydrogen production and water loss.

The float charging voltage is an important factor in operation. If the float charging voltage is too low, the charging current will not be sufficient to prevent self-discharge, leaving the battery less than fully charged and vulnerable to sulfation. If the float charging voltage is too high, the thermal generation and rate of water loss will be unacceptably high. These considerations are especially true for VRLA batteries, which are especially susceptible to water loss and to thermal runaway if the battery is overheated.

Equalization Charging

Individual cells in a battery are always slightly different and experience slightly different environmental conditions. For this reason, cell-to-cell differences in state-of-charge arise as the battery is cycled. As a result, some cells are not fully charged at the end of the charging procedure, while others experience a significant degree of overcharge. This can damage the life of the battery, as the overcharged cells lose water more quickly, and undercharged cells experience sulfation.

For flooded batteries, this can be corrected by occasional *equalization charging*, in which the battery is charged to a high voltage for a long period of time. As each cell reaches full charge, the energy input goes entirely towards electrolysis, even as less fully charged cells continue to accept charge. At the end of charging, all cells have reached full charge. Since a significant amount of electrolysis can occur during equalization charge, it must be performed in ventilated areas, and should be followed by a check on the water level in the cells. The frequency with which this operation is performed depends on the frequency of cycling, and can range from a few times a year to a few times a week.

The gassing produced during an equalization charge is often also used to correct electrolyte stratification, which also results during cycling (see below).

Equalization charging is not practical for VRLA batteries, which cannot tolerate the level of overcharge necessary for this procedure.

Water Replacement

Most flooded batteries require regular maintenance in the form of *watering*. In this operation, distilled water is added to each individual cell to replace water lost through evaporation and electrolysis. This is usually done three to four times a year for batteries operating on float charge. In some cases, the water addition is automated; more commonly, it is a manual operation.

Watering is not necessary for VRLA and maintenance-free flooded batteries. Since water addition can inhibit recombination mechanisms and produce potentially dangerous situations, these types of batteries are built without ports through which water can be added.

Cell Post Maintenance

Over time, the cell post on the battery can corrode as it is exposed to battery fumes and humidity. The post is usually covered with a conductive grease to prevent excessive corrosion. The post should be inspected at regular intervals to ensure that the post is not corroded and that the cell interconnections are fit properly to the cell.

Disposal and Recycling

As with any battery system, disposal of lead-acid batteries is an important part of the life cycle. The environmental and safety hazards associated with lead have lead to a number of regulations concerning the handling and disposal of lead-acid batteries. Partly for this reason, Lead-acid batteries are among the most recycled products in the world. In 1999, 93.3% of all battery lead was recycled, along with a large percentage of the plastic used in battery cases [4].

Generally, old lead-acid batteries are accepted by lead-acid manufacturers for recycling. In some cases, old batteries can actually be sold for their lead content, particularly if large quantities are involved. These batteries are separated into component parts. The lead plates and grids are smelted to purify the lead for use in new batteries. Plastic cases are chopped, washed, and recycled. The acid electrolyte is neutralized, scrubbed to remove dissolved lead, and released into the environment.

Many states in the United States charge an additional fee to cover environmental issues related to lead. A straight fee is usually charged when the battery is purchased.

Technology Status

Notable Vendors and Developers

As might be imagined, the number of lead-acid vendors is very large. Most lead-acid batteries are produced and marketed regionally, although many manufacturers are owned or affiliated by larger concerns. The following organizations are of particular note to those interested in batteries for transmission and distribution applications.

Alcad (www.alcad.com)

Alcad is a European battery manufacturer that is far better known for its nickel-cadmium batteries than for lead-acid. The company manufactures a small line of VRLA batteries, lead-selenium, and Planté lead-acid batteries for stationary applications, and is one of the few manufacturers who continue to produce the Planté design.

Bolder Technologies

Bolder Technologies, now closed, was noted for its extensive work in researching and marketing the Thin Metal Film (TMF) form of lead-acid batteries, a high-power form that uses extremely thin electrodes deposited on films and rolled into a spiral-wound case to allow very high power densities. This had natural advantages for markets such as power quality.

Mass manufacturing of this form of technology proved to be difficult, however. Johnson Controls, Inc. licensed Bolder’s technologies for its Inspira line of products, but eventually withdrew the line in favor of Optima Batteries’ spiral-wound AGM batteries. In April 2001, Bolder filed for bankruptcy, and in December 2001 its assets were sold to GP Batteries International Limited, a Singapore-based manufacturer of batteries.

C&D Technologies (www.cdtechno.com)

C&D Technologies, based in Blue Bell, PA, is a major supplier of lead-acid batteries to the utility and telecommunications industries. The company has two divisions: The Powercom division, and the Dynasty division.

The Powercom division produces flooded batteries for UPS and standby power applications. Of particular interest are their stationary batteries, which are commonly used in substation and utility generation plants to power switchgear and control systems. Powercom also produces AGM-type VRLA batteries for standby power applications and solar power backup.

The Dynasty division produces VRLA batteries of both gelled and AGM types for various applications, including utility deep-cycle and high power applications.

East Penn Manufacturing Co. (www.eastpenn-deka.com)

East Penn has been producing lead-acid batteries and related products since 1946. The company manufactures a large number of lead-acid products. It sells most products under the Deka brand name, but also manufactures batteries for other vendors. The company is best known for its SLI products and for industrial deep-cycle batteries used for materials handling. The company also produces a line of VRLA batteries under the Unigy brand.

EnerSys (www.enersysinc.com)

EnerSys, Inc., based in Reading, PA, is the former industrial battery manufacturing division of Exide Corporation. Exide sold its industrial battery operations, as well as the rights to the use of the Exide name in that market, to Yuasa Corporation in 1991. The resulting company was named Yuasa-Exide, which changed its name to EnerSys in 2000. In 2002, EnerSys purchased the Energy Storage Products group of Invensys, including Hawker Energy Products

Enersys is best known for its tubular-positive plate deep-cycle flooded Exide Ironclad batteries, which are used widely in forklifts and other material-handling applications. The company also produces flat-plate deep-cycle batteries under the General Battery brand, and flooded and VRLA storage batteries under a number of brands. In the utility industry, the PowerSafe brand is best known for its use in switchgear and reserve power in power plants.

Exide Technologies (www.exide.com)

Exide Technologies, headquartered in Princeton, NJ, was founded as the Electric Storage Battery Company in 1888 near Philadelphia, PA by W.W. Gibbs, an executive in a gas utility who recognized the potential in electric lighting and foresaw the business potential in electricity storage. The company sold large storage batteries to the nascent electric utility industry and later developing the Exide ("excellent oxide") battery for electric vehicles. The company eventually settled into selling automotive starting and industrial deep cycle batteries.

The company sold its industrial battery division in 1991, along with the rights to the Exide name used in that market. Subsequently, Exide concentrated on automotive batteries until 2000, when it purchased GNB and reentered the industrial battery market. The company sells flooded and VRLA deep-cycle batteries for industrial applications such as material handling and UPS applications, under brands such as Absolyte, Marathon, Sprinter, Champion, and GNB. Many of these batteries are used in utility applications such as switchgear backup power.

GNB Batteries (www.gnb.com)

GNB Industrial Battery Company was purchased by Exide Technologies in September 2000. GNB continues to be an important brand name for Exide, particularly in utility applications, where the GNB name is well-associated with flooded lead-acid batteries used in substations and generation backup applications. The GNB Absolyte and Marathon products were among the first VRLA batteries used in the utility industries.

HAGEN Batterie AG (www.hagenbatterie.de)

HAGEN, based in Soest, Germany, is a manufacturer of a number of types of lead-acid industrial batteries used in motive and stationary applications, as well as automotive batteries. The company was responsible for the deep-cycle lead-acid batteries used in the BEWAG battery facility in Berlin. HAGEN has since been acquired by Exide Technologies.

Hawker Energy Products (www.hawker-batteries.com)

Hawker Energy Products (now owned by Enersys) is a well-known company that produces a number of deep-cycle lead-acid products, including both flooded and VRLA products. The company has a number of VRLA brands which are used very widely in UPS systems, both small and large. The company has also developed high-rate VRLA batteries (such as those marketed under the DataSafe brand) for standby power.

Hoppecke Batterien GmbH (www.hoppecke.com)

Hoppecke is a German battery company founded in 1927 in Brilon, Germany by Carl Zoellner. The company manufactures batteries of several chemistries, including lead-acid, nickel-cadmium, and nickel-metal hydride, for a large variety of applications. The company makes a variety of stationary lead-acid products, including a line of high-endurance stationary tubular plate batteries, as well as deep-cycle motive batteries.

Japan Storage Battery (www.nippondenchi.co.jp or www.gsbattery.com)

Japan Storage Battery, also known as GS Battery, was founded by Genzo Shimadzu in Kyoto, Japan in 1895, and is the oldest storage battery manufacturer in Japan. In Japan, the company builds a wide variety of batteries, including a number of SLI, stationary, and VRLA lines. In the United States, GS is best known for its VRLA batteries. In July 2003, the company agreed to merge with Yuasa Corporation to form GS Yuasa Corporation.

Johnson Controls (www.johnsoncontrols.com)

Johnson Controls, Inc. (JCI) is a major manufacturer of lead-acid batteries, mostly for transportation applications. Their product line includes SLI and deep-cycle batteries, the latter usually the types used for material handling (forklifts) and golf carts. JCI continues to do a great deal of research on lead-acid technologies, and has placed special emphasis on its development of new technologies to support hybrid electric vehicles. The company no longer supports development of lead-acid batteries specifically for stationary applications.

Storage Battery Systems (www.sbsbattery.com)

Storage Battery Systems (SBS) was founded in 1915 to supply batteries for electric vehicles. When the electric vehicle market disappeared, the company adapted to selling batteries for forklifts and other motive applications in industry. The company continues to sell batteries for material handling as well as selling batteries for UPS, power quality, and stationary applications, including batteries for substation and generation plant switchgear. The company is known for both flat-plate and tubular batteries, and both flooded and VRLA designs.

Tyco Electronics Power Systems (http://www.power.tycoelectronics.com)

Tyco Electronics Power Systems now owns the design and manufacturing rights for the famous Bell Laboratories Round Cell, a stationary battery cell widely used in telecommunications switching stations. The Round Cell was first developed by AT&T Bell Laboratories in the early 1970s as a ground-up approach to battery design to produce an extremely long-life battery with a life expectancy of 40 years in the intended application.

The unique design of the Round Cell arises out of the designers’ desire to reduce the effects of corrosion, which is largest source of failure in this application. The Round Cell uses circular pure-lead grids, along with tetrabasic lead sulfate on the positive plate, to reduce corrosion and grid growth. The circular shape also counters the effects of plate expansion. The plates are stacked horizontally, with positive electrodes conducting current to a collector on the outside of the stack, while the negative current collector runs along the core of the cylinder [1].

Figure 6-10
Tyco Electronics Power Systems Round Cell *(Courtesy Tyco Electronics)*

Extensive testing since the early 1970s confirms that the Round Cell has an impressive life expectancy. The plate growth found during life testing was less than originally expected, so that at present the company predicts a life in excess of 70 years in this application [15].

This battery, while impressive for low-current-rate applications, has limited application when higher power levels are required. For this reason, the Round Cell has not found extensive use in the utility industry.

Varta (www.varta.com)

Varta, a German manufacturer of consumer, industrial, and automotive batteries, began as the firm Büsche and Müller in Hagen, Germany. The company was well-known for its presence in most major battery markets, including consumer, automotive, and industrial batteries. The company has recently undergone some restructuring, including the sale of the consumer division to Rayovac and the automotive division to Johnson Controls. The industrial battery line, including most stationary lead-acid batteries, is now owned by Enersys, although most are still sold under the Varta name.

Yuasa Corporation (http://www.yuasa-jpn.co.jp)

Founded in 1913, Yuasa is a major manufacturer of lead-acid batteries in Japan, with products in the SLI, stationary, and industrial deep-cycle areas. In 1991, Yuasa purchased the North American stationary battery business from Exide Corporation, forming Yuasa-Exide Corporation. This company became Yuasa Corporation, USA, and was eventually spun off from the parent company as Enersys. Yuasa continues to sell batteries in the Japanese market, but retains only a small SLI plant in North America. In July 2003, the company agreed to merge with Japan Storage Battery to form GS Yuasa Corporation.

Past Demonstration Facilities

One of the earliest uses of lead-acid batteries was their use in utility generation plants to provide peak power and to level loads over the day. As the size of the grid grew, this application became less common due to the relative expense of the batteries. Modern utilities have attempted to renew this application through the construction of very large bulk storage plants. Appropriately, the first such plants were constructed with lead-acid batteries.

More recently, power quality has become a valuable commodity. Smaller, more flexible battery systems, dedicated to providing power quality for a single facility or a small area, have become attractive options. This is particularly true because these systems can be produced and operated at relatively low cost.

Of the large demonstration projects described here, three are bulk storage projects designed for power management, and the last is a smaller system designed for power quality purposes.

BEWAG Battery Facility (Berlin, Germany)

Berliner Kraft and Licht AG (BEWAG) is the electric utility for was once West Berlin. During the Cold War, West Berlin was disconnected from the East German grid, and effectively functioned as an “island” network. BEWAG was faced with two major problems: maintaining a sufficient power reserve that could be utilized quickly for lead-frequency control, and providing sufficient spinning reserve to overcome generation contingencies.

In the mid-1970s, BEWAG began studying energy storage option to address these problems. The utility considered several storage options before settling on lead-acid batteries. In 1979, a test facility was constructed to collect data on battery operation and life. This test facility operated from 1981 to 1986. Subsequently, a full-scale system was designed and developed. The system was installed in late 1986 and began operation in early 1987.

The BEWAG battery plant had a power rating of 8.5 MW_{ac} for 60 minutes of operation, or 17 MW_{ac} for 20 minutes of operation. The battery consisted of 7,080 HAGEN OCSM 1000 A-h flooded lead-acid cells. These cells were arranged in 12 strings of 590 cells each, producing a nominal voltage of 1180 V_{dc}. The batteries were equipped with heat exchangers for thermal management. Air lift pumps were used to circulate electrolyte, and an automatic water filling system served to replace water lost through gassing. The cells were also maintained with a regular equalizing charge.

The strings were connected in parallel into two AEG 8.5MW_{ac} line-commutated, 12-pulse, thyristor-based inverters. These inverters were rated for 3-phase 30 kV_{ac} output, and were designed for 4-quadrant operation. During load-frequency control operations, one inverter was used while the other served as a standby backup. The operational priority was switched weekly to maintain equal operating time. When the battery was required to supply spinning reserve, both inverters were used together. The plant was controlled remotely, allowing unmanned operation.

The BEWAG plant served its purpose for a number of years without requiring anything but occasional maintenance. After three years of operation, a small number of battery failures were found. These were tracked to the automatic watering system, which was inadequately supplying cells with water. This problem was fixed. It was also found that the system was operated much more than anticipated, leading to more heating in the cells. To prevent overheating, the system was operated at less than full power. Subsequently, the thermal system was improved to allow better cooling, allowing the system to operate at full power.

Chino Battery Storage Project (Chino, CA)

The Chino Battery Storage Project was initiated by Southern California Edison in 1986 to build a battery energy storage system to investigate the feasibility of load-leveling operations. In addition, the system was designed to serve a number of secondary other functions, including load-leveling, load-following, transmission and distribution deferral, economic dispatch, frequency regulation, voltage and reactive power control, and black-start operation.

The system had a power rating of 10 MW_{ac} and an energy storage capacity of 40 MW_{ac}-h. The battery consisted of 8256 two-volt Exide GL-35 flooded lead-acid cells rated at 2600 A-h at a four hour discharge rate to 80% DOD, and rated for 2,000 deep discharge cycles. These cells were arranged in eight parallel strings of 1032 cells each, to produce a 2000 V_{dc} nominal voltage. The electrolyte was agitated with compressed air to prevent stratification. The battery DC-to-DC efficiency was measured at 81%, with an overall plant ac-to-ac efficiency of 70% [21].

The power conditioning system (PCS) for the Chino project was supplied by General Electric and consisted of a 10MVA_{ac} bi-directional 18-pulse, stepped-wave GTO thyristor-based voltage source converter, operating between 1750 V_{dc} and 2800 V_{dc} on the battery side and 12 kV_{ac} 3 phase on the utility side. The converter was also capable of producing up to 10MVAr of leading and lagging reactive power. The inverter demonstrated an efficiency of 96%. The overall system efficiency was calculated to be 72% ac-to-ac, including losses in the battery and inverter and losses in building operation [5].

United Engineers & Constructors was responsible for engineering and overall system integration for the Chino plant [22].

The Chino system was completed in July, 1988, and was tested extensively over the next two years, successfully meeting all requirements. Only a few problems were encountered with the battery system. During a heavy rainstorm, water leakage through the facility roof caused a short circuit between the PCS and one of the battery strings, leading to a small fire, which caused minor damage. This problem was solved by improving the robustness of the electrical safety system and enhancing the weather resistance of the building. Later, several lead-acid cells developed leaking joints; these cells were replaced by the manufacturer. There were also some PCS related failures which affected the operation of the facility, but were not caused by the battery system [5].

In January 1991, SCE took full control of the plant, converting it into a system resource. The plant continued operation until June 1997, when it was retired [6].

Puerto Rico Electric Power Authority (PREPA) Battery Electric Storage System (BESS) (Sabano Llana, Puerto Rico)

The PREPA system was constructed in the early 1990s, primarily to provide much-needed spinning reserve and frequency control for the relatively small grid on Puerto Rico. The system was rated for 21 MW_{ac} and 14 MW_{ac}-h, and was designed to provide 20 MW_{ac} for 15 minutes, plus a 15 minute ramp down to 0MW_{ac} for spinning reserve. It was designed to do this an average of 55 times each year, and would be recharged at off-peak times (such as after midnight). The system could also inject or absorb 10 MW_{ac} instantaneously for continuous frequency control [7].

The PREPA battery consisted of 6000 flooded lead-acid cells supplied by C&D Batteries, Inc. The cells were of a flat plate design using lead-calcium alloy grids in both plates. The cells were arranged in 6 parallel strings of 1000 cells each, for a nominal system voltage of 2000 V_{dc}. The system included cell electrolyte agitation with compressed air, and an automatic cell watering system.

The PREPA PCS was a 20 MVA_{ac} bi-directional 18-pulse, stepped-wave GTO thyristor-based voltage source converter, an improved version of the 10 MW_{ac} converter that formed the PCS for the Chino Battery Storage Project. The battery input voltage was 2000V_{dc}, and the nominal AC line voltage was 13.2 kV_{ac}. General Electric also supplied the PCS. United Engineers & Constructors were responsible for engineering and the overall system integration.

The PREPA BESS was completed in 1994 and experienced its first use in November of that year when a 410 MW_{ac} steam plant went down, resulting in a 21% system overload. While load-shedding was necessary, the impact was mitigated by 80MW_{ac} as a result of the BESS [7]. In 1998, in the aftermath of Hurricane Georges, the plant was able to maintain voltage support on the only remaining transmission line from San Juan to the northeastern part of the island. Despite these successes, the BESS ran into several problems, especially with accelerated failure of the lead-calcium cells. As a result, the plant was taken off line in 1999. Studies continue in bringing the plant back on-line with new types of cells, as well as constructing new plants elsewhere in Puerto Rico.

S&C Electric PureWave System

In 1991, the U.S. Department of Energy, through Sandia National Laboratories, began a program to develop a large scale modular battery energy storage system. Among the first contracts awarded went to AC Battery Corporation, which began development of a battery energy storage system designed to protect utility customers from the detrimental effects of voltage disturbances [12]. Eventually named the PM250, the prototype design consisted of a 250 kW_{ac}, 167 kW_{ac}-h building block, each containing its own set of power electronics, so that modules could be stacked to configure to build a system of capacity up to 10 MW_{ac}. The novel design used maintenance-free SLI batteries, originally designed to start trucks, to reduce the cost and maintenance associated with conventional stationary batteries. Since most applications of this system involved high-power discharged for short periods of time, the use of SLI batteries was sufficient to meet most requirements.

The first application of this approach came in a facility-backup system tested in San Ramon, CA under the auspices of Pacific Gas & Electric (PG&E) in 1996. This system, called the PQ2000, was designed for power quality purposes, to provide ride-through power for short periods at a facility level during power disturbances and temporary outages. The system, called the PQ2000, was rated at 2 MW_{ac} for 10 seconds, and was constructed from 250 kW_{ac} modules similar to the PM250 modules, but with additional power electronics to support the power quality requirements of the system. The system successfully passed extensive testing to prove its capability to mitigate or eliminate power quality problems at a facility level.

There were several lessons learned, in the course of the exercise: control logic, what do you do if the energy runs out before the utility comes back, how do get longer storage times.

The design was further developed during the Multi-Mode Transportable Battery Energy Storage System (TBESS) project, funded by EPRI and Salt River Project (SRP). The TBESS, based on the PQ2000 product, was intended to be a standardized, factory-manufactured, fully integrated system, available to electric energy providers for both power quality and power management (or load shifting) purposes. The first TBESS was installed at SRP in 1997, and was tested extensively for both. The system was judged to be very successful at meeting power quality requirements, but less successful at meeting the power management requirements. This was due in part to the relative immaturity of the power management hardware and software. In addition, the SLI batteries used in the system required more frequent replacement in a power management mode, reducing the economic value of the system in that mode.

These projects resulted in a number of lessons learned. Power electronics and control algorithms for power management and power quality systems were developed, tested, and improved. Most important, systems capable of short discharges of large power are easily capable and economically viable with present technology, for applications such as power quality. But applications such as power management, which require longer duration, are less viable. Future improvements in the technology are required before these applications become possible.

In 1997, AC Battery Corporation was acquired by Omnion Power Engineering, which was in turn acquired by S&C Electric Company in 1999. S&C Electric continues to sell the PQ2000 system under the new trade name, PureWave.

Since the original project, S&C has upgraded the capability of the Purewave system in several ways. System capacities up to 16 MW_{ac} are now possible. In addition, based on field experience, S&C Electric has increased the battery time to 30 seconds at full load. The PCS has also been modified to operate in current source mode to permit "soft-transfer" of the protected load from battery power to a back-up generator system to allow protection of critical loads from long term power outages.

Technology Development

Despite a history of over a hundred years, lead-acid batteries are undergoing constant technological development. Development has, in fact, increased in pace in the last thirty years, with the introduction of the VRLA battery and new applications in the rapidly growing telecommunications, personal electronics, and information industries.

Advanced Lead-Acid

General efforts to advance lead-acid technology, particularly those aiming for improved performance or life, often fall under the description "advanced lead-acid battery development." In recent years, lead-acid battery development has focused on reducing maintenance requirements and extending operating life. The most prominent efforts rely on the use of different grid alloys, such as lead-tin or lead-selenium, to reduce corrosion and plate expansion while minimizing water loss due to gassing.

VRLA technologies, themselves the result of "advanced lead-acid" efforts to produce sealed maintenance-free batteries, are undergoing continual improvement in operational life. Some of this progress has come through the use of better manufacturing methods to improve uniformity across cells, reducing the chance that individual cells could be overcharged or undercharged. The last few years have also seen the use of integrated power electronics to control charging and discharging at the cell level, improving the life of cells significantly. While such measures often increase the cost of VRLA products, in many cases these costs are still lower than competing energy storage systems.

Thin Metal Film (TMF) Lead-Acid

One area of research which saw intense activity until relatively recently is the development of thin metal film (TMF) lead-acid battery. The TMF battery is a VRLA battery in which the electrodes are formed from pure lead as very thin foils. A thin separator is sandwiched between the foils, and the electrodes rolled up in a "jelly-roll" form, which is then encased in a can. The extremely thin electrode allows a very high power density at the expense of energy density.

Many companies, such as Bolder Technologies (see above), investigated TMF lead-acid batteries for a variety of applications. The manufacturing of such devices proved very difficult, however, and the battery suffers from the relatively poor cycle life of pure-lead electrodes. Most TMF research has been abandoned or continues at a relatively low level. If high-power/ low-energy applications become important in the future, the research may be revived.

T&D System Energy Storage System Applications

Select Applications for Lead-Acid Battery Systems

This section presents the select applications for which lead-acid is suited and describes the key features of the lead-acid systems when configured to meet the select application requirements. Screening economic analyses have shown that lead-acid battery systems are potentially competitive for some of the single function applications as well as some of the combined function applications, which are described in detail in Chapter 3. The following list briefly summarizes all of the Chapter 3 applications, with a reiteration of the key application requirements. Those for which lead-acid technology is best suited are enclosed by borders.

<u>Single Function Applications</u>

Application A: Grid Angular Stability (GAS) – mitigation of power oscillations by injection and absorption of real power at periods of 1 to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 20 oscillatory cycles, cumulatively equivalent to a full power discharge (FPD) of 1 second duration; 1 event per day; 10 events per year. Valued at the cost of alternative solutions.

Application B: Grid Voltage Stability (GVS) – mitigation of degraded voltage by additional reactive power plus injection of real power for durations up to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 1 second FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application C: Grid Frequency Excursion Suppression (GFS) – "prompt" spinning reserve (or load) for mitigating load-generation imbalance. Requires energy storage to discharge real power for durations up to 30 minutes. The reference duty cycle for analysis is standby for infrequent events characterized by 15-minute FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application D: Regulation Control (RC) – system frequency regulation in concert with load following. The reference duty cycle for analysis is characterized by continuous cycles equivalent to 7.5-minute FPD and charge cycle (triangular waveform), 2 cycles per hour deployed with 10 minutes advance notice. Valued at market rates.

Application E: Spinning Reserve (SR) – reserve power for at least 2 hours with 10 minute notice. The reference duty cycle for analysis is standby for infrequent events characterized by 2-hour FPD, 1 event per day, 10 events per year. Valued at market rates.

Application F: Short Duration Power Quality (SPQ) – capability to mitigate voltage sags (e.g., recloser events). The reference duty cycle for analysis is standby for infrequent events characterized by 5 seconds FPD, 1 event per hour, 5 events per day, 100 events per year. Valued at the cost of alternative solutions.

Application G: Long Duration Power Quality (LPQ) – SPQ, plus capability to provide several hours reserve power. The reference duty cycle for analysis is standby for infrequent events characterized by SPQ plus standby for 4 hours FPD, 1 event per year. Valued at the cost of alternative solutions.

Application H: 3-hr Load Shifting (LS3) – shifting 3 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 3-hour FPD, 1 event per day, 60 events per year. Valued at market rates.

Application I: 10-hr Load Shifting (LS10) – shifting 10 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 10-hour FPD, 1 event per day, 250 events per year. Valued at market rates.

<u>Combined Function Applications (In the Order Noted)</u>

Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC)

Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR)

Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR)

Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR)

Application C5: Combined Applications I, D, E (LS10 + RC + SR)

Lead-Acid Battery System Compliance With Application Requirements

Lead-acid performance parameters discussed above were used to develop approximate sizes and operational parameters for systems meeting the application requirements for the selected lead-acid applications described in the previous section. Key factors in sizing lead-acid systems include:

- Duration of the discharge. For applications requiring very short discharge, a SLI battery may be sufficient. For longer discharges, a stationary cell would be more appropriate.

- Depth of discharge. Lead-antimony cells are more appropriate for deep-discharge systems, while lead-calcium cells can be used to minimize standby losses if deep discharge is not required.
- Selection of the type of PCS and pulse factor (which determines the minimum discharge voltage and therefore the PCS cost as described in Section 5).
- State-of-charge management to ensure that the required power and energy are accessible and that the battery is appropriately recharged
- Thermal management to ensure that cell temperatures are maintained within the acceptable range and that the rate of heat loss is appropriate to the application
- Cycle life management to ensure that the system is operated within the service life of equipment, which is especially important for combined function, high cycle applications such as load shifting with regulation control.

Performance aspects of lead-acid battery systems for the selected applications are described below and summarized in Table 6-1. The reference power for all applications is 10 MW_{ac}. In each of these applications, several possible products can be used to build the system. In the examples below, the systems are designed with a specific product by way of example, and should not be understood to advocate a particular product for this application.

- **Application A:** Grid Angular Stability (GAS) – This application requires that the system continuously detect and mitigate power oscillations, up to 10 times a year. Oscillations require that the system inject power for the equivalent of 1 second at the full power rating. This duty cycle can be accommodated by a simple SLI battery, such as those used in the S&C PureWave system. Forty-eight (48) Delco 1150 batteries, each with a nominal voltage of 12 V_{dc}, are arranged in a string with a nominal voltage of 576 V_{dc}. A device sized for 10 MW_{ac} would require 37 such strings, for a total of 1776 Delco batteries. The minimum voltage for each string would be 408 V_{dc}. The system would be equipped with a Type III PCS with a pulse factor of 5. During most of the time, the system would be at standby, with a net efficiency of 98%. The battery must be replaced every 5 years, but requires no other maintenance.
- **Application B:** Grid Voltage Stability (GVS) – This application requires that the system continuously detect and mitigate power oscillations. Oscillations require that the system alternately inject and absorb full power, for an equivalent of a 1 sec full power discharge. This duty cycle can be accommodated by a simple SLI battery, such as those used in the S&C PureWave system. Forty-eight (48) Delco 1150 batteries, each with a nominal voltage of 12 V_{dc}, are arranged in a string with a nominal voltage of 576 V_{dc}. A device sized for 10 MW_{ac} would require 37 such strings, for a total of 1776 Delco batteries. The minimum voltage for each string would be 408 V_{dc}. The system would be equipped with a Type III PCS with a pulse factor of 5. During most of the time, the system would be at standby, with a net efficiency of 98%. The battery must be replaced every 5 years, but requires no other maintenance.
- **Application C:** Grid Frequency Stability (GFS) – This application requires that the system continuously detect and mitigate infrequent frequency excursions, up to 10 events per year. Stationary cells must be used in this application, and the relatively frequent duty cycle

requires us to employ lead-antimony cells rather than lead-calcium. For this example, we connect GNB NAX-33 multipurpose stationary cells to produce series strings, each 1000 cells long. Three such strings are connected in parallel, and connected to a Type I PCS sized for a minimum discharge voltage of 1750 V_{dc}. The net efficiency of the battery is 97.9%. The battery can be expected to last 15 years.

- **Application F:** Short Duration Power Quality (SPQ) – This application requires that the system continuously detect and mitigate infrequent PQ events lasting up to 2 seconds. This duty cycle can be accommodated by a simple SLI battery, such as those used in the S&C PureWave system. Forty-eight (48) Delco 1150 batteries, each with a nominal voltage of 12 V_{dc}, are arranged in a string with a nominal voltage of 576 V_{dc}. A device sized for 10 MW_{ac} would require 37 such strings, for a total of 1776 Delco batteries. The minimum voltage for each string would be 408 V_{dc}. The system would be equipped with a Type III PCS with a pulse factor of 5. During most of the time, the system would be at standby, with a net efficiency of 98%. The battery must be replaced every 5 years, but requires no other maintenance.

Table 6-1
Lead-Acid Battery System Compliance With Application Requirements

Applications	Single Function					Combined Function		
	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	App B: GVS -- 1 sec FPD per cycle, 10 events/yr, 1 event/d	App C: GFS -- 15 min FPD per cycle, 10 events/yr, 1 event/d	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr	App G: LPQ -- 4 hr FPD per cycle, 1 event/yr	App C1: GFS +GAS + GVS + RC	App C3: SPQ + LS3 + RC + SR	App C4: LPQ + LS3 + RC + SR
Energy Storage Selection								
Type of Product	S&C PureWave	S&C PureWave	GNB NAX-33	S&C PureWave	GNB NCX-33	GNB NAX-33	GNB NAX-33	GNB NAX-33
Number of Strings	37	37	3	37	12	3	3	12
Pulse Factor	5.0	5.0	1.0	5.0	1.0	1.0	4.0	1.0
Max Charge Voltage	726	726	2,250	726	2,250	2,250	0	0
Min Discharge Voltage	408	408	1,750	408	1,750	1,750	1,750	1,750
Maximum DOD, %	100%	100%	100%	100%	100%	100%	80%	80%
Cumulative Cycle Fraction	0%	0%	5%	0%	13%	100%	99%	99%
Replacement Interval, yr	5	5	15	5	20	15	10	10
PCS Selection								
PCS Type (Chapter 5)	III	III	I	III	I + SST	I	III	I + SST
Duty Cycles								
Grid Support or Power Quality (GS or PQ)								
Power, MW	10	10	10	10	10	10	10	10
Event Duration, Hr	0.000	0.000	0.25	0.001	4	0.25	0.001	4
Load Shifting (LS)								
Power, MW							3.2	10.5
Load Shift Energy, MWh/yr							581	1,891
Load Shift Losses, MWh/yr							224	728
Cycle Life Fraction							87%	60%
Regulation Control (RC)								
Power, MW						10.0	3.2	10.0
Hours per day, hr						3	2	6
Days per year, days						40	5	12
RC, MW-Hours/yr						1,200	32	720
RC Losses, MWh/yr						116	3	69
Cycle Life Fraction						95%	4%	31%
Spinning Reserve (SR)								
Power, MW							3.2	10
SR, MW-Hours							25,925	80,608
SR Losses, MWh/yr							25	77
Cycle Life Fraction							7.54%	5.62%
Summary System Data								
Standby Hours per Year	8,760	8,760	8,739	8,760	8,749	8,619	8,081	8,097
System Net Efficiency, %	98.0%	98.0%	97.9%	98.0%	97.9%	97.8%	97.8%	96.7%
Energy Storage Standby Efficiency, %	100.0%	100.0%	99.9%	100.0%	99.9%	99.9%	99.9%	99.5%
PCS Standby Efficiency, %	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%	98.2%	98.2%
System Footprint, MW/sqft (MW/m^2)	0.0058 (0.0621)	0.0058 (0.0621)	0.0012 (0.013)	0.0058 (0.0621)	0.0003 (0.0037)	0.0012 (0.013)	0.0012 (0.013)	0.0003 (0.0037)
Energy Storage Footprint, MW/sqft (MW/m^2)	0.0221 (0.238)	0.0221 (0.238)	0.0014 (0.0153)	0.0221 (0.238)	0.0004 (0.0038)	0.0014 (0.0153)	0.0014 (0.0153)	0.0004 (0.0038)

Note: System net efficiency includes losses for energy conversion and system standby expressed on an annual basis, i.e., one minus inefficiency, where inefficiency equals the ratio of annual energy losses to the product of system rated power times 8760 hours, expressed in percent.

- **Application G:** Long Duration Power Quality (LPQ) – This application requires that the system continuously detect and mitigate infrequent PQ events and provide reserve power for up to 4 hours, with one event per year.. This application cannot be serviced with an SLI battery, but the infrequent use indicates that a lead-calcium battery would most likely be sufficient and would reduce energy and water losses during standby service. GNB NCX-33 multipurpose stationary cells are connected to produce series strings, each 1000 cells long. Twelve such strings are connected in parallel, and connected to a Type I PCS sized for a minimum discharge voltage of 1750 V_{dc}. The net efficiency of the system is 97.9%. Because of the extremely infrequent use, the battery can be expected to last 20 years.

- **Application C1:** Combined Applications C, A, B, D (GFS +GAS + GVS + RC) – This application requires that the system continuously detect and mitigate infrequent GFS, GAS, and GVS events lasting to 15 minutes for GFS. The system will also provide RC functions at 10 MW_{ac} for 3 hours per day, 40 days per year. Stationary cells must be used in this application, and the continuous duty cycle associated with RC requires us to employ lead-antimony cells rather than lead-calcium. For this example, we connect GNB NAX-33 multipurpose stationary cells to produce series strings, each 1000 cells long. Three such strings are connected in parallel, and connected to a Type I PCS sized for a minimum discharge voltage of 1750 V_{dc}. The net efficiency of the system is 97.8%. The large number of cycles can be tolerated because the depth-of-discharge for each cycle is quite small, about 10.1%. The battery can be expected to last about 15 years.
- **Application C3:** Combined Applications F, H, D, E (SPQ + LS3 + RC + SR) – This application requires that the system continuously detect and mitigate infrequent SPQ events lasting to 5 seconds. In addition, the system will provide load shifting services at 3.2 MW_{ac} for 3 hours per day for 60 days a year, and spinning reserve services at 3.2 MW_{ac} for 8,034 hours. The system will be capable of providing a cursory level of RC services at 3.2 MW_{ac} for 2 hours per day, 5 days per year. Note that because of the deep discharge and repeated cycling requirements associated with LS3, RC, and SR, this battery design must be substantially different from the design for SPQ only. Stationary cells must be used in this application, and the repeated deep-discharges associated with LS3 require that we employ lead-antimony cells rather than lead-calcium. For this example, we connect GNB NAX-33 multipurpose stationary cells to produce series strings, each 1000 cells long. Three such strings are connected in parallel, and connected to a Type I PCS sized for a minimum discharge voltage of 1750 V_{dc}. The net efficiency of the system is 97.8%. The battery can be expected to last about 15 years.
- **Application C4:** Combined Applications G, H, D, E (LPQ + LS3 + RC + SR) – This application requires that the system continuously detect and mitigate infrequent PQ events and provide reserve power for up to 4 hours, with one event per year. In addition, the system will provide load shifting services at 10 MW_{ac} for 3 hours per day for 60 days a year, and spinning reserve services at 10 MW_{ac} for 8,061 hours. The system will be capable of providing a cursory level of RC services at 3.2 MW_{ac} for 6 hours per day, 12 days per year. Stationary cells must be used in this application, and the repeated deep-discharges associated with LS3 require that we employ lead-antimony cells rather than lead-calcium. For this example, we connect GNB NAX-33 multipurpose stationary cells to produce series strings, each 1000 cells long. Twelve such strings are connected in parallel, and connected to a Type I PCS sized for a minimum discharge voltage of 1750 V_{dc}. The net efficiency of the system is 97.8%. The battery can be expected to last about 15 years.

Benefit and Cost Analyses

Lead-Acid Battery Pricing and Integrated System Costs

Lead-acid batteries are mature, well-established products with commodity pricing. Changes over time will be dependent largely on fluctuations in the commodity price of lead. The pricing of batteries is often dependent on the number of products bought at once. Large orders can often bring significant discounts on the price of batteries.

For the Handbook's specified deployment date of 2006 and rating of 10 MW_{ac}, the prices are based on manufacturers' quotes from 2003 for bulk quantities of batteries, including interconnection hardware and racks. Replacement modules over the assumed 20 year project life are assumed to follow the same cost structure.

Lead-Acid Product	2003 Bulk Prices
GNB NAX-33 Stationary Single Cell (Lead-Antimony)	\$700
GNB NAX-33 1000-Cell String	\$802,000
GNB NCX-33 Stationary Single Cell (Lead-Calcium)	\$700
GNB NCX-33 1000-Cell String	\$802,000
PureWave Battery Module (Energy Storage Only)	\$12,000

For the stationary cell systems, the related scope of supply includes the cells themselves, the cell interconnection hardware, mounting racks, automated watering systems, and compressed air electrolyte agitation. The racks are assumed to be 2-tier back-to-back racks designed for seismic zone 1. The PureWave battery modules each contain 48 Delco 1150 SLI batteries, along with interconnection hardware, racks, DC disconnect device, outdoor enclosure, and an HVAC system.

The cost of integrated lead-acid systems is obtained by combining the cost of the lead-acid battery scope of supply with the appropriate PCS and BOP costs as described in Chapter 5. The PCS includes the power converter plus the grid disconnect and breaker protection, transformers, controller(s) to synchronize one or more lead-acid strings with the grid, and all equipment necessary for serving the load and isolating the lead-acid battery system. The BOP scope of supply consists of grid connection at the point of common coupling, land and improvements (e.g., access, services, etc.). The BOP cost is set at a nominal cost of \$100/kW$_{ac}$ for the stationary cell systems, and at \$50/kW$_{ac}$ for the Purewave systems because of the extensive system engineering already in place for the Purewave product. The PCS and BOP costs shown in Table 6-2 are based on the methodology described in Chapter 5. Systems for short duration discharge applications (e.g., SPQ) use "discontinuous" IGBT-based PCS which accommodate high currents for brief periods at reduced cost compared to continuous ratings as described in Section 5.3. The cost of enclosure is not included in the scope of supply for stationary batteries, so that the cost of interior space, foundations for the batteries, and HVAC installation is included at \$100/sqft in accordance with general past experience. The PureWave battery module includes an outdoor enclosure, so that the cost of space is calculated at \$20/sqft, covering the cost of constructing a foundation.

Table 6-2
Capital and Operating Costs for Lead-Acid Battery Systems

Applications	Single Function					Combined Function		
	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	App B: GVS -- 1 sec FPD per cycle, 10 events/yr, 1 event/d	App C: GFS -- 15 min FPD per cycle, 10 events/yr, 1 event/d	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr	App G: LPQ -- 4 hr FPD per cycle, 1 event/yr	App C1: GFS +GAS + GVS + RC	App C3: SPQ + LS3 + RC + SR	App C4: LPQ + LS3 + RC + SR
Battery Capacity, MWh$_{ac}$	0.003	0.003	2.50	0.006	40	2.50	10	40
PCS Initial Cost, \$/kW	153	153	165	153	215	165	173	215
BOP Initial Cost, \$/kW	50	50	100	50	100	100	100	100
Battery Initial Cost \$/kW	60	60	315	60	1,258	315	315	1,258
Battery Initial Cost \$/kWh	220,000	220,000	1,258	110,000	315	1,258	325	315
Total Capital Cost, M\$	2.6	2.6	5.8	2.6	15.7	5.8	5.9	15.7
O&M Cost – Fixed, \$/kW-year	7.3	7.3	16.5	7.3	43.5	16.5	17.6	48.8
O&M Cost– Variable, \$/kW-year	6.7	6.7	7.0	6.7	6.9	7.0	6.5	7.7
NPV Disposal Cost, \$/kW	13.0	13.0	0.8	13.0	1.8	0.8	1.4	5.4

Note: The total initial cost may calculated in two ways:
1. By mutiplying the sum of PCS, BOP and Battery initial costs expressed in \$/kW by the reference power,
2. OR by mutiplying the sum of PCS and BOP expressed in \$/kW by the reference power and then adding the product of Battery Initial cost expressed in \$/kWh and the Battery Capacity

Fixed O&M costs are based on \$2/kW for the PCS as required by provisions in Chapter 5, plus battery maintenance in accordance with the vendor. This maintenance varies depending on the type of battery and the application. Fixed O&M costs are based on labor costs of \$50 per hour.

The recommended maintenance program for stationary batteries consists of continuous remote monitoring and detailed inspections conducted four times a year, which include:

- Visual inspection for damage, leakage, or other physical problems with cells, interconnections, and connecting cables

- Cleaning the tops and sides of cells to remove dirt and deposited electrolyte salts
- Measurement of voltage, resistance, and specific gravity of electrolyte for each cell
- Measurement of resistance between terminals of adjacent cells
- Retorquing terminal connections as necessary
- Confirming the accuracy of DC voltage, DC current, and temperature sensors as necessary

In addition, stationary cells require the addition of water to replace water lost during charging and standby periods. Lead-antimony batteries require more frequent watering than lead-calcium batteries. Batteries undergoing frequent cycling require more frequent watering than batteries that spend most of their time on standby. In these assessments, the frequency of water addition varies between once a year for a lead-calcium battery on standby, to once a month for a lead-antimony battery undergoing regular cycling.

There are no annual maintenance costs for the PureWave systems, built from the maintenance-free Delco 1150 battery. These batteries must be replaced every 5 years, however.

In addition, an allowance for annual property taxes and insurance, based on 2% of the initial total capital costs, is included in the fixed O&M costs.

Variable O&M costs for the system include the cost of electrical losses to maintain the PCS and the battery during hot standby intervals.

An allowance for lead-acid battery disposal costs is also included at the end of battery life, covering the cost of removing the battery from the plant. Although old batteries can be sold for scrap, the prices are quite low and are not included in this analysis.

Lifecycle Benefit and Cost Analysis for Lead-Acid Battery Systems

Further insight to the value of energy storage can be gained through lifecycle cost analyses using a net present value (NPV) methodology and comparison with alternatives. The financial parameters in Table 6-3 are used to assess the applications described in the preceding sections and the assumed electricity rate structure is presented in Table 6-4.

Table 6-3
Financial Parameters

Dollar Value	2003
System Startup	June 2006
Project Life, years	20
Discount Rate (before tax), %	7.5
Property Taxes & Insurance, %/year	2
Fixed Charge Rate, %/year	9.81

Table 6-4
Electric Rates

Load Shifting On Peak Period	3	10
Number Cycles per year	60	250
On-Peak Energy, $/MWh	120	80
Off-Peak Energy, $/MWh	20	
Yearly Average Energy Charge, $/MWh	38	
Regulation Control, $MW-Hour (power), $/MWh	16	
Spinning Reserve, $MW-Hour (power), $/MWh	3	
Transmission Demand Charge, $/kW-mo	5	

The results of lifecycle cost benefit analyses of select lead-acid battery applications are summarized in Table 6-5 and discussed below. The bases and methodology used in valuing energy storage applications is described in detail in Chapter 4. The details of the cost benefit analysis for each application are discussed below.

Table 6-5
Summary of Benefit and Cost Analyses of Lead-Acid Battery Systems

	Single Function					Combined Function		
Applications	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	App B: GVS -- 1 sec FPD per cycle, 10 events/yr, 1 event/d	App C: GFS -- 15 min FPD per cycle, 10 events/yr, 1 event/d	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr	App G: LPQ -- 4 hr FPD per cycle, 1 event/yr	App C1: GFS +GAS + GVS + RC	App C3: SPQ + LS3 + RC + SR	App C4: LPQ + LS3 + RC + SR
Alt Solution Value, $/kW	750	500	750	1,000	1,500	750	1,500	2,000
Initial Installed Cost, M$	2.63	2.63	5.79	2.63	15.73	5.79	5.87	15.73
Total Costs, M$	(4.9)	(4.9)	(8.6)	(4.9)	(20.9)	(8.6)	(9.5)	(26.2)
Total Benefits, M$	7.50	5.00	7.5	10.0	15.0	7.7	16.8	25.8
Benefit to Cost Ratio	1.54	1.03	0.87	2.05	0.72	0.89	1.77	0.99
NPV, M$	2.6	0.1	(1.1)	5.1	(5.9)	(0.9)	7.3	(0.4)
Battery Type	S&C PureWave Battery Module	S&C PureWave Battery Module	GNB NAX-33 1000-cell string	S&C PureWave Battery Module	GNB NCX-33 1000-cell string	GNB NAX-33 1000-cell string	GNB NAX-33 1000-cell string	GNB NAX-33 1000-cell string
Number of Modules	37	37	3	37	12	3	3	12
Battery 2006 Price, K$/module	12	12	802	12	802	802	802	802
Battery Price for NPV=0, K$/module	38	13	540	63	395	580	2250	785

Application A: Grid Angular Stability (GAS) – This application was evaluated on the assumption that an alternative system capable of mitigating GAS events can be obtained for capitalized acquisition and operating costs of $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 6-5, this application yields a NPV of $2.6 million on an initial investment of $2.63 million. As a measure of sensitivity of NPV with respect to alternative system costs, Figure 6-11 illustrates the change in NPV over a range of $500 to $1000/kW and shows that lead-acid systems compete favorably against alternative solutions across this entire range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the PureWave system were increased from $12 to $38 thousand per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $750/kW.

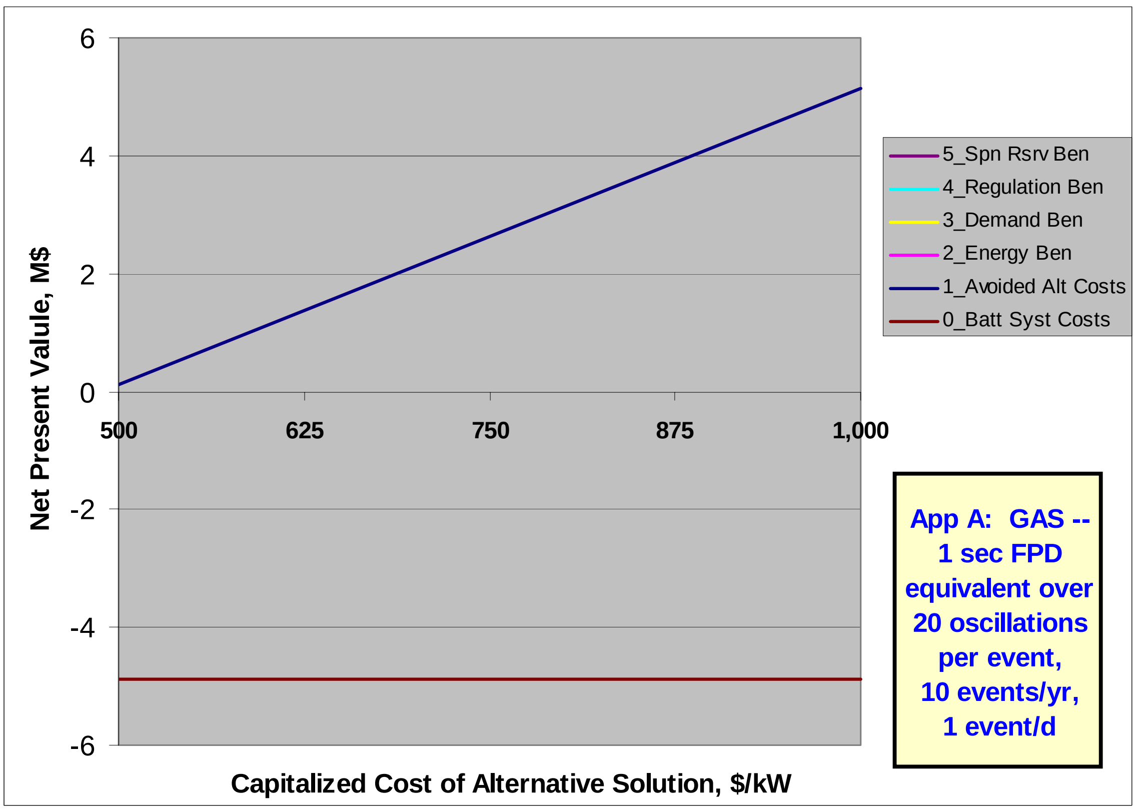

Figure 6-11
Application A: Lead-Acid System NPV vs Cost of Alternative System

Application B: Grid Voltage Stability (GVS) – This application was evaluated on the assumption that an alternative system capable of mitigating GVS events can be obtained for capitalized acquisition and operating costs of $500/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 6-5, this application yields a NPV of $0.1 million on an initial investment of $2.63M. As a measure of sensitivity of NPV with respect to alternative system costs, Figure 6-12 illustrates the change in NPV over a range of $250 to $750/kW and shows that lead-acid systems compete favorably against alternative solutions with a net capitalized cost in excess of $490/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the PureWave system were increased from $12 to $13 thousand per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $500/kW.

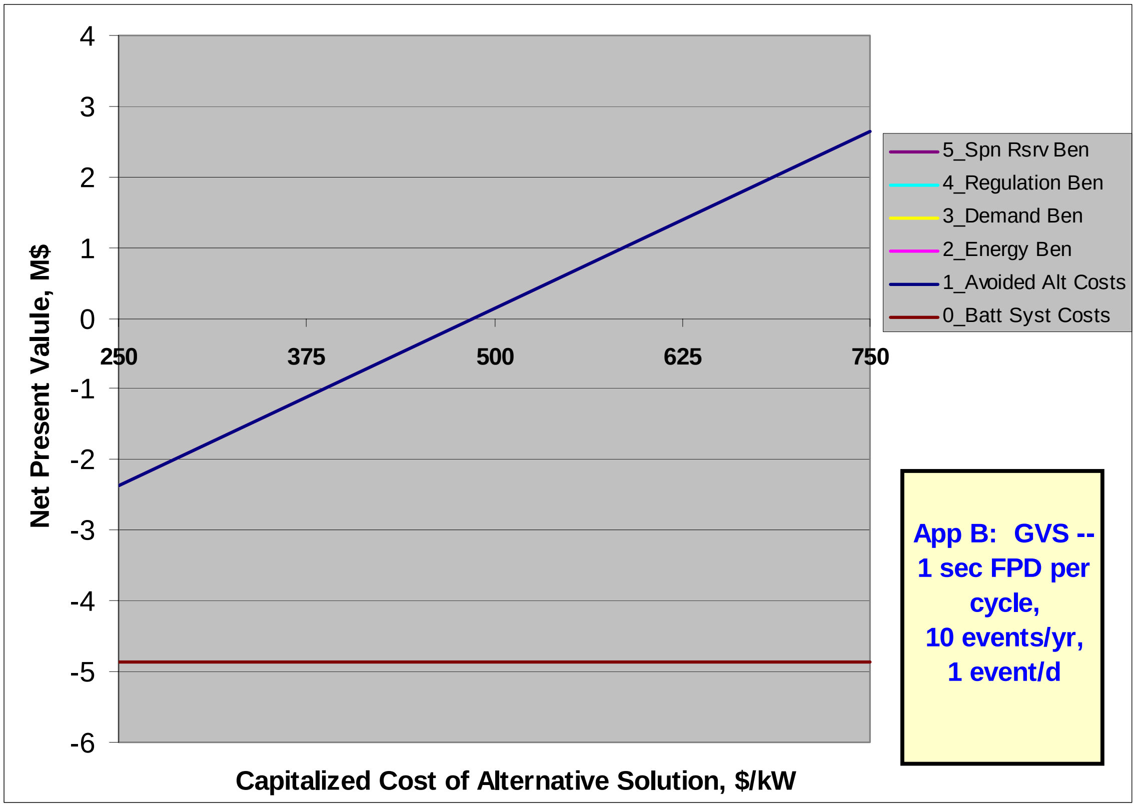

Figure 6-12
Application B: Lead-Acid System NPV vs Cost of Alternative System

Application C: Grid Frequency Stability (GFS) – This application was evaluated on the assumption that an alternative system capable of mitigating GFS events can be obtained for capitalized acquisition and operating costs of $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 6-5, this application yields a negative NPV of $(1.1) million on an initial investment of $5.8 million. As a measure of sensitivity of NPV with respect to alternative system costs, Figure 6-13 illustrates the change in NPV over a range of $500 to $1500/kW and shows that lead-acid systems compete favorably against alternative solutions with net capitalized costs in excess of about $860/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the lead-acid string were decreased from $802 to $540 thousand per string, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $750/kW.

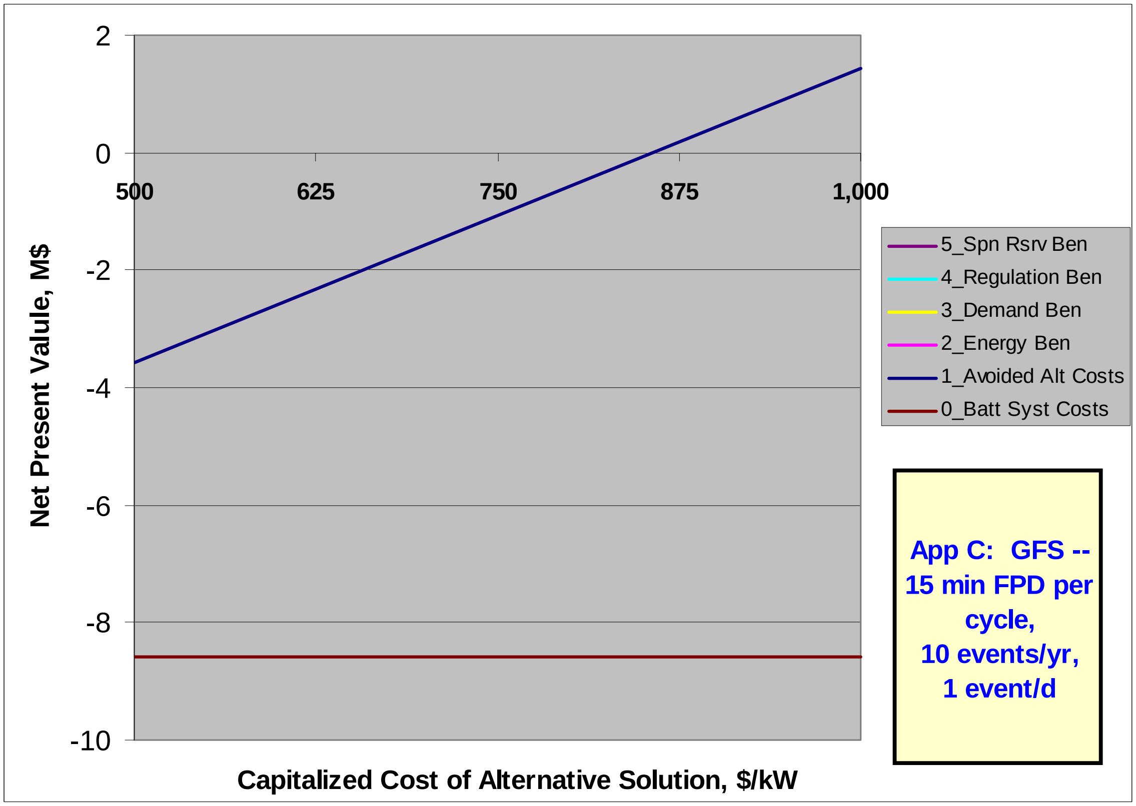

Figure 6-13
Application C: Lead-Acid System NPV vs Cost of Alternative System

Application F: Short Duration Power Quality (SPQ) – This application was evaluated on the assumption that an alternative system capable of mitigating SPQ events can be obtained for capitalized acquisition and operating costs of about $1000/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 6-5, this application yields a NPV of $5.1 million on an initial investment of $2.63 million. As a measure of sensitivity of NPV with respect to alternative system costs, Figure 6-14 illustrates the change in NPV over a range of $500 to $1500/kW and shows that lead-acid systems compete favorably against alternative solutions with net capitalized costs in excess of about $490/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the PureWave system were increased from $12 to $63 thousand per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $1000/kW.

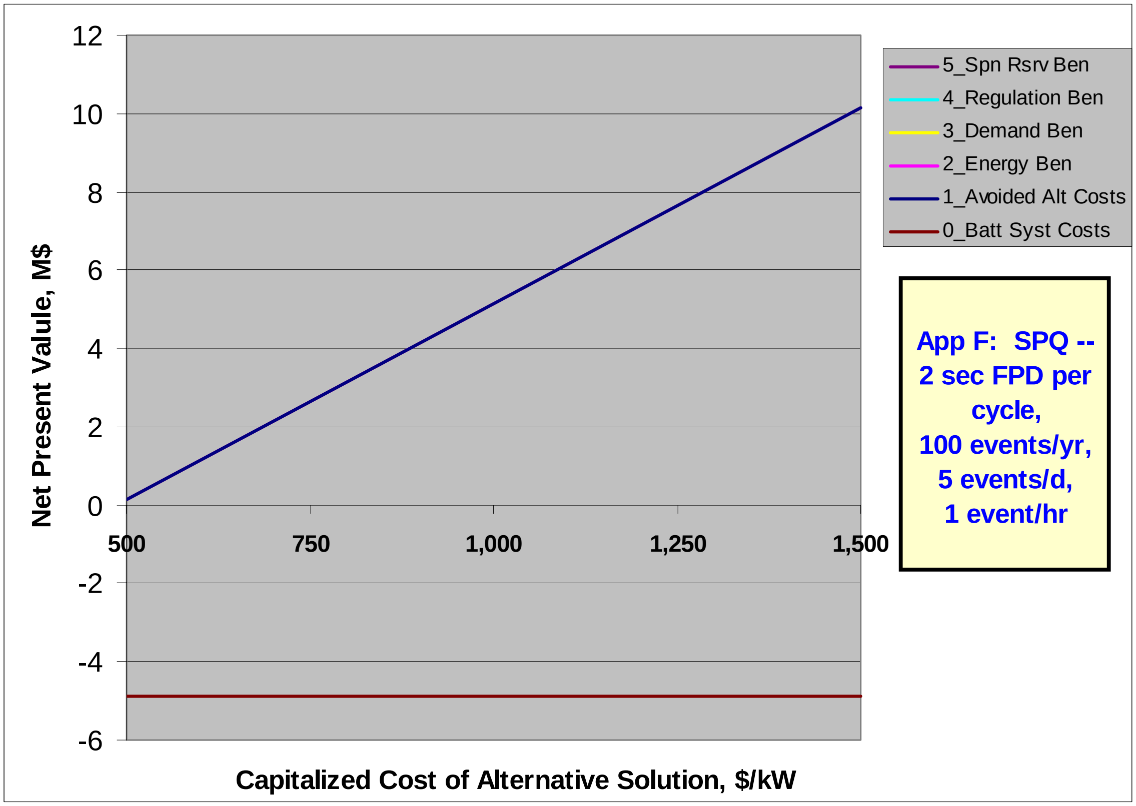

Figure 6-14
Application F: Lead-Acid System NPV vs Cost of Alternative System

Application G: Long Duration Power Quality (LPQ) – This application was evaluated on the assumption that an alternative system capable of mitigating LPQ events can be obtained for capitalized acquisition and operating costs of about $1500/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 6-5, this application yields a negative NPV of $(5.9) million on an initial investment of $15.73 million. As a measure of sensitivity of NPV with respect to alternative system costs, Figure 6-14 illustrates the change in NPV over a range of $1000 to $2000/kW and shows that lead-acid systems compete marginally at the upper end of this range. The system will compete against alternative solutions with net capitalized costs in excess of about $2090/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the lead-acid string were decreased from $802 to $395 thousand per string, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $750/kW.

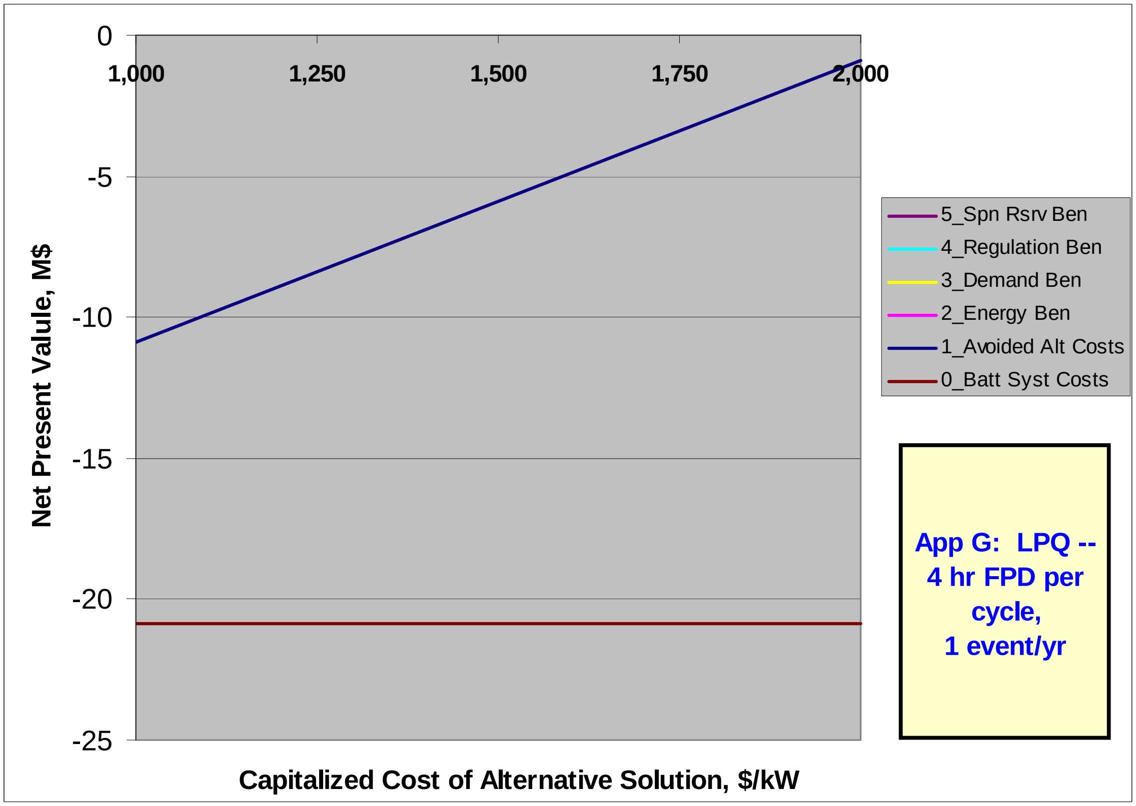

Figure 6-15
Application G: Lead-Acid System NPV vs Cost of Alternative System

Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC) – This application was evaluated on the assumption that an alternative system capable of mitigating GFS, GAS and GVS events can be obtained for capitalized acquisition and operating costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rate for regulation control is also included in the valuation. As shown in Table 6-5, this application yields a negative NPV of ($0.9M) for an initial investment of $5.79M on this basis. As a measure of the sensitivity of NPV with respect to alternative system costs, Figure 6-16 illustrates the change in NPV over a range of $500 to $1000/kW, as well as the incremental value of regulation control, and shows that this lead-acid system will compete favorably against alternative solutions with net capitalized costs in excess of about $850/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the lead-acid battery were decreased from $802 to $580 thousand per string, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $750/kW.

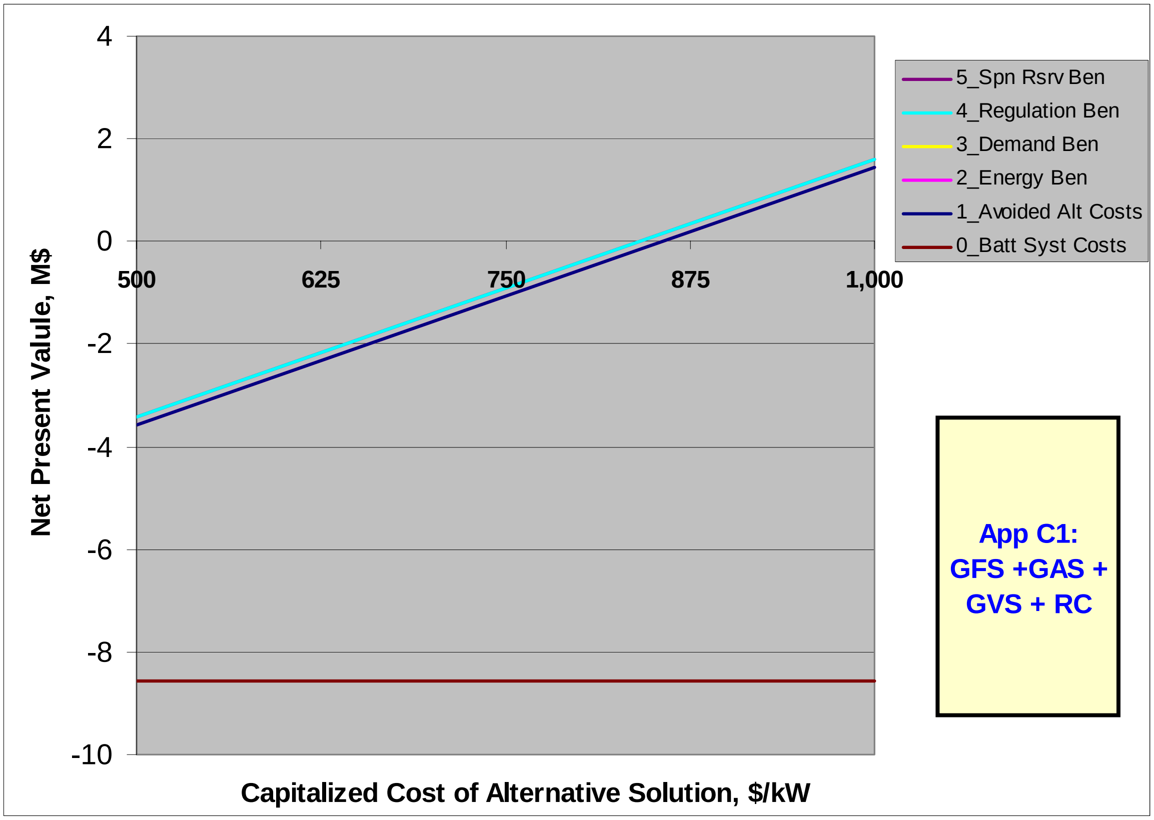

Figure 6-16
Application C1: Lead-Acid System NPV vs Cost of Alternative System

Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating SPQ events, plus avoided LS3 related upgrade costs, can be obtained for net capitalized costs of about $1500/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 3-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Table 6-5, this application yields a NPV of $7.3 million for an initial investment of about $5.87 million on this basis. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 6-17 illustrates the change in NPV over a range of $1000 to $2000/kW, as well as the incremental value of load shifting (both energy and demand), regulation control and spinning reserve functions. With these value elements, lead-acid systems will compete very favorably against alternative solutions over this range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the lead-acid battery were increased from $802 thousand to $2.25 million per string, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $1500/kW.

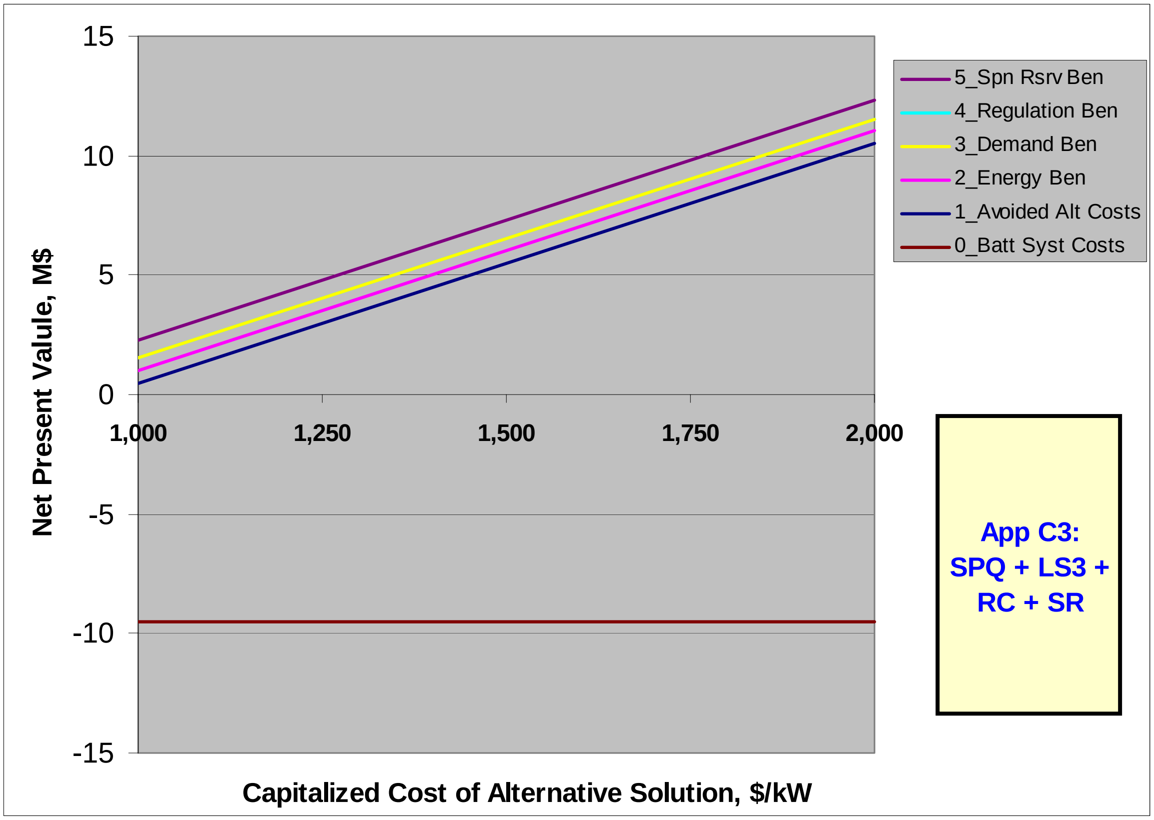

Figure 6-17
Application C3: Lead-Acid System NPV vs Cost of Alternative System

Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating LPQ events, plus avoided LS3 related upgrade costs, can be obtained for net capitalized costs of about $2000/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 3-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Table 6-5, this application yields a negative NPV of $(0.4) million for an initial investment of about $15.73 million on this basis. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 6-18 illustrates the change in NPV over a range of $1500 to $2500/kW, as well as the incremental value of load shifting (both energy and demand), regulation control and spinning reserve functions. With these value elements, NAS systems will compete favorably against alternative solutions with net capitalized costs in excess of about $2050/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the lead-acid battery were decreased from $802 to $785 thousand per string, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $2000/kW. Note that the cost-to-benefit ratio is actually lower for this combined application than for the SPQ application alone. This result arises from the substantial difference in battery design necessitated by the repeated deep-cycle requirements for LS3, RC, and SR.

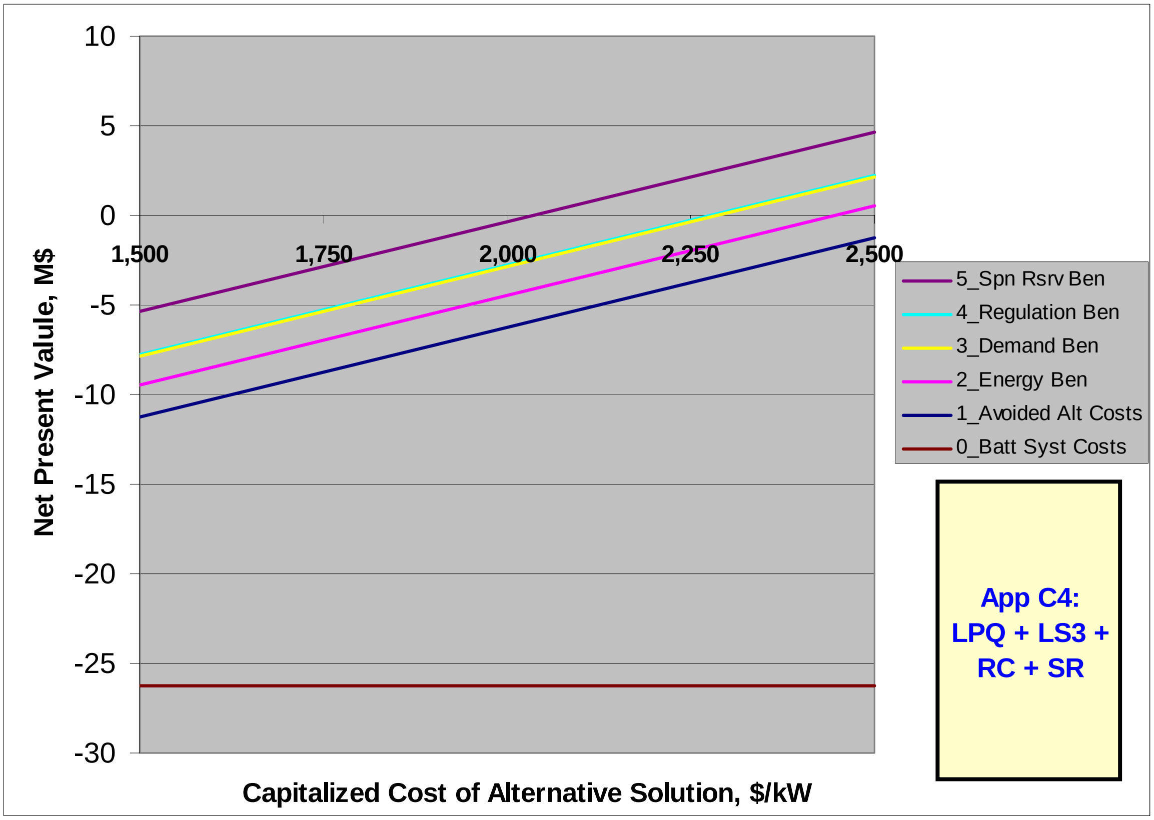

Figure 6-18
Application C4: Lead-Acid System NPV vs Cost of Alternative System

Interpreting Results From Benefit-Cost Analyses

In general, lead-acid battery systems are expected to be marginally competitive for most single function applications, but can be attractive investments for the combined function application described above. They are especially attractive in SPQ applications which allow the use of cheap SLI batteries and a "discontinuous" IGBT-based PCS.

The reader is reminded that the foregoing analyses are intended as a guide to the initial consideration of energy storage options, and that these analyses are based on representative electric rates and costs for alternative systems as described in Chapter 4. The assumptions used herein should be reviewed in light of project specific applications, alternative solutions, electric rates and financial parameters.

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7
NICKEL-CADMIUM AND OTHER NICKEL ELECTRODE BATTERIES

Introduction

The favorable attributes of nickel-electrode batteries have been recognized ever since Thomas Edison introduced the first commercial nickel-iron battery a century ago. The same attributes have also made these chemistries attractive for bulk energy storage systems in utility applications. Most recently, the Golden Valley Electric Association in Fairbanks, Alaska, has selected a nickel-cadmium-based system for use in a Battery Energy Storage System (BESS) which began operation in September, 2003.

Several materials have been matched with nickel to produce a variety of battery technologies, each with its own advantages and disadvantages. This chapter will examine five nickel-metal technologies that have potential for use in T&D applications: nickel-cadmium, nickel-zinc, nickel-hydrogen, nickel-metal-hydride, and nickel-iron. The chapter will put emphasis on vented nickel-cadmium batteries, since they are the nickel-electrode batteries most commonly proposed for use in utility applications. The other nickel-electrode chemistries will be described where important to transmission and distribution applications.

The nickel-cadmium battery was invented by Waldmar Jungner in 1899, but found little application because of its relative expense and difficulty of manufacture. The nickel electrode was subsequently used by Edison in the nickel-iron battery, the first significant commercial product incorporating the nickel electrode. This battery was used by Edison and his competitor, Westinghouse, in a number of electricity storage applications, including bulk storage and electric vehicles. Eventually, as the electricity grid grew to a point where bulk storage was no longer economic, and as electric vehicles gave way to gasoline-powered automobiles, these uses faded.

Research into nickel electrodes would continue despite these setbacks. The sintered-plate nickel electrode was invented in the 1930s, allowing higher current densities and reducing the difficulty of manufacturing. The 1940s saw development of the sealed nickel-cadmium cell which quickly found application with the military. As design manufacturing methods improved, cost dropped dramatically. Consumer nickel-cadmium cells appeared in the late 1970s, in time for the boom in portable electronics.

Development of nickel-metal hydride cells began in the 1970s. Portable nickel-metal hydride cells were introduced in the late 1980s and by the mid-1990s had largely supplanted nickel-cadmium batteries in many portable applications, before themselves losing market share to lithium ion batteries.

Nickel-cadmium batteries, meanwhile, continue to be used widely in stationary (including rail), military, and commercial aircraft applications, where their high current capabilities made them preferable to other nickel-electrode batteries. They especially found application as replacements for lead-acid batteries where greater reliability or better temperature performance was crucial. They are also still used in many low-end consumer goods such as cordless phones and electric shavers, because of their low cost and weight.

Description

Varieties of Nickel-Electrode Battery Technologies

There are five common battery technologies that use the nickel-electrode: nickel-iron (NiFe), nickel-cadmium (NiCd), nickel-hydrogen (NiH_2), nickel-metal hydride (NiMH), and nickel-zinc (NiZn). Of these, NiCd and NiMH are the most common and well-known.

Nickel-iron batteries were first designed by Thomas Edison as a replacement for the lead-acid battery. The battery is well-known for its extreme durability and relative tolerance of nearly any kind of abuse, physical or operational. The battery can be overcharged, over-discharged, left on open-circuit stand for extended periods, and short-circuited without seriously affecting the relatively long cycle life. The battery has several limitations, however, including high variability with temperature, poor charge retention, low power density, and gas evolution during operation [1]. Today, NiFe batteries have been replaced in most applications by cheaper low-maintenance lead-acid batteries, or by nickel-cadmium batteries.

Nickel-cadmium batteries are the most common nickel-electrode batteries in the utility industry today. These batteries come in several forms, including industrial pocket-plate, vented sintered-plate, and sealed designs. NiCd batteries are relatively tolerant of abuse (though less so than NiFe), and have a higher energy density, longer cycle life and require less maintenance than lead-acid batteries, at a somewhat greater cost.

Perhaps the most damaging indictment of the NiCd battery is the fact that it contains cadmium, a highly toxic metal. For this reason, production, use, and disposal of NiCd batteries are generally carefully monitored. The industry has made significant efforts to promote recycling, so that almost all cadmium from the battery industry is recovered. In addition, the cadmium in NiCd batteries is contained, and rarely presents a problem for the end user.

NiCd batteries have a reputation for exhibiting the so-called “memory-effect.” This term is commonly used to describe a variety of phenomena that result in reversible loss of capacity. This effect is correctible through a reconditioning process in which the battery is discharged fully and then recharged. Properly stated, the memory effect does not occur with industrial nickel-cadmium batteries, although other forms of reversible capacity loss do.

NiCd batteries are used in a variety of applications, including substation batteries and bulk storage. Because they are relatively inexpensive, have good energy density characteristics and excellent power delivery capability, NiCd batteries are the most commonly used nickel-electrode batteries in the utility industry, and are likely to remain so in the near future.

Nickel-hydrogen batteries are special batteries used mostly in aerospace applications. These devices can be considered a hybrid system between batteries and fuel cells, as the positive electrode is nickel oxyhydroxide while the negative electrode is gaseous hydrogen. The entire cell assembly is sealed within a pressure vessel that serves to contain the hydrogen when battery is fully charged. While these batteries have many advantages, including extremely long cycle life, low maintenance, and high reliability, they are also the most costly of the nickel-electrode technologies. This has prevented their adoption in most terrestrial applications.

Nickel-metal hydride battery technology is an outgrowth of NiH_2 technology, also using hydrogen as the negative electrode. In NiMH batteries, the hydrogen is absorbed in a metal alloy, allowing a higher volumetric energy density at the cost of specific energy. The battery must be sealed to prevent the hydrogen from escaping. The metal alloy is usually a complex mix of a number of elements, and can vary to a significant degree from design to design. The NiMH technology generally has higher energy density than an equivalent NiCd battery as well as a less-pronounced tendency for reversible capacity loss, and somewhat better cycle life. In addition, the NiMH technology does not contain cadmium, which many users see as an environmental advantage. NiMH tends to be slightly more expensive than NiCd, however, and less tolerant of electrical abuse. In particular, NiMH batteries are sensitive to overcharge and to high-rate discharge. Hence, NiMH batteries have replaced NiCd in relatively low-current applications, including portable computers, cellular phones, and camcorders, but not in high-rate applications such as power tools. The production of large NiMH batteries has been limited, in part due to the difficulty of manufacturing the metal-hydride complex in a uniform fashion. Hence there have been few NiMH batteries used in the utility industry, except in an experimental fashion.

Nickel-zinc is the least mature of the nickel-electrode battery technologies. This technology has been investigated for over a century, but development has been significantly hindered by the inability to develop a long-life rechargeable zinc electrode. Recent developments seem to have made this technology more likely to succeed. The NiZn battery is likely to have a slightly higher energy density than a NiCd, at a somewhat lower cost (though still more costly than a lead-acid battery). The NiZn battery would also be also cadmium free. The cycle life will probably be poorer than NiCd, however, and the battery is likely to have all the idiosyncrasies of both the nickel electrode (including reversible capacity loss) and the zinc electrode (including dendritic growth and shape change). The technology may still be economically viable in applications where high energy density and low cost are at a premium.

Electrode Chemistry and Construction

All of the nickel-based battery types have similar performance characteristics, though their compositions are quite different. The following sections describe the chemistry, construction, and performance of each of these electrodes.

The Nickel Electrode

The positive electrode for all nickel-chemistry batteries is composed of nickel hydroxide, $Ni(OH)_2$, in the form of a spongy mass. During charge, the nickel hydroxide is converted to nickel oxyhydroxide, NiOOH.

The electrolyte is almost always aqueous potassium hydroxide, $KOH \cdot (H_2O)$, at a concentration between 25% and 40% by weight. A small quantity of lithium hydroxide, $LiOH \cdot (H_2O)$, is added to improve cycling performance. The nickel-chemistry batteries are differentiated principally by their negative electrodes, and by minor differences in construction.

In the discharge reaction that occurs on the nickel electrode, nickel oxyhydroxide combines with water to produce nickel hydroxide and a hydroxide ion:

Positive: $$NiOOH + H_2O + e^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} Ni(OH)_2 + OH^- \qquad \textbf{Eq. 7-1}$$

As in the case of most battery electrodes, the electrode chemistry of the nickel electrode is actually much more complex than the simple chemical equation, which is merely an approximation of the true reactions.

During overcharge, the nickel electrode produces oxygen from water:

Positive (Overcharge): $$H_2O + \tfrac{1}{2} O_2 + e^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} 2OH^- \qquad \textbf{Eq. 7-2}$$

In vented NiCd batteries, this oxygen is released to the atmosphere. In most other nickel batteries, however, the oxygen is retained in the cell and migrates to the negative electrode, where it recombines with the negative electrode active material.

Several types of nickel-electrodes are commonly used in commercial nickel-electrode batteries. Pocket-plate electrodes, the oldest type, are constructed with thin, nickel-coated steel strips, which are perforated to allow passage of electrolyte. These strips are fashioned into pockets, into which the nickel hydroxide active material is placed. Several such pockets are interlocked to form an electrode, which is placed into a steel frame which acts as a mechanical support and current collector (Figure 7-1).

Sintered-plate electrodes are constructed with an internal nickel substrate, usually in the form of a grid. This substrate acts as a mechanical support and current collector. Nickel powder is attached loosely to this substrate, and the assembly is sintered in a reducing atmosphere at 1000ºC. Alternatively, the powder is sometimes added to a liquid to produce a slurry, which is then placed on the substrate and sintered. The finished electrode is then impregnated with nickel hydroxide active material. Sintered-plate electrodes are used in high-rate flooded batteries as well as most sealed batteries.

Figure 7-1
Pocket Plate Nickel-Cadmium Battery [1]

Nickel-fiber electrodes are manufactured by a few companies. These plates are manufactured from a mat of nickel fibers, or from a mat of nickel-plated plastic fibers. When plastic fibers are used, nickel is plated onto the fibers with vacuum deposition followed by electroplating, and the plastic subsequently burned off. This creates a mat of hollow nickel fibers, which is then impregnated with nickel hydroxide.

Pasted foam nickel electrodes have gained acceptance for some technologies. Nickel foam is produced by depositing nickel on a plastic foam, and then burning off the foam to leave nickel. This foam is then pasted with the nickel oxhydroxide active material. Pasted foam electrodes are simpler to manufacture in large quantities, and are widely used in portable NiCd and NiMH cells. They have recently been considered for use in industrial NiCd batteries.

In addition to nickel hydroxide, the active material usually contains some percentage of other materials to improve performance. In pocket-plate electrodes, a quantity of graphite is added to the nickel hydroxide inside the pocket to improve conductivity. In addition, cobalt hydroxide is commonly added to the active material for both pocket-plate and sintered systems. The cobalt material is added in a quantity from 2 to 5% of the weight of the active material, and serves to stabilize the crystal structure of the nickel hydroxide, improving life and capacity.

Negative Electrodes

Of the negative electrodes under discussion, the cadmium electrode has historically been the most popular to use with the nickel electrode. This is in part because of its relatively high energy density and power capability, but also because of problems associated with the other popular electrodes. Iron generally produces an inferior energy density to cadmium when used with a nickel electrode. Hydrogen and metal hydride electrodes require sealed cells, which usually limits their high-current capability. Zinc electrodes have significant technical obstacles in rechargeable designs. The main disadvantages associated with cadmium electrodes are the cost (although they are still cheaper than metal hydrides) and the toxicity of the material.

The following sections describe the negative electrodes in detail.

Cadmium Electrodes

In nickel-cadmium batteries, the negative electrode is composed of metallic cadmium, Cd, when charged, which is oxidized to cadmium hydroxide, $Cd(OH)_2$, on discharge:

Negative (NiCd): $$Cd + 2OH^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} Cd(OH)_2 + 2e^- \qquad \textbf{Eq. 7-3}$$

The cadmium electrode has historically been constructed to match the nickel electrode, either in a pocket-plate or a sintered-plate configuration. In both cases, the substrate is identical to the nickel substrate, but cadmium hydroxide is substituted for nickel hydroxide during the impregnation process.

More recently, some manufacturers have used plastic-bonded cadmium electrodes, which allow somewhat better internal resistance and cycling characteristics. In these electrodes, the cadmium active material is mixed with a solvent and a plastic binder, usually polytetrafluroethylene (PTFE). The mix is then extruded or pasted onto a current collector, usually a sheet of nickel-plated perforated steel.

A quantity of iron, and sometimes nickel, is added to the cadmium electrode to stabilize the crystal structure material. Graphite is sometimes added to improve conductivity. It should be noted that cadmium is a highly toxic material and is handled with extreme care in the manufacturing process, though this should not affect the typical user of nickel-cadmium batteries.

Metal Hydride Electrodes

Metal hydride electrodes are somewhat more complex than the cadmium electrode. The electrode itself is hydrogen stored in a metal alloy. This metal alloy is capable of absorbing and desorbing hydrogen as the battery charges and discharges. Effectively, the discharge reaction involves oxidation of the metal hydride complex to produce water and the metal alloy:

Negative (NiMH): $$M\text{-}H + OH^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} M + H_2O + e^- \qquad \textbf{Eq. 7-4}$$

A number of different alloys are used as the hydrogen storage material, falling into two principal classes, AB_5 and AB_2 materials. AB_5 materials are rare-earth alloys based on lanthanum nickel, LaN_5, alloys. Other rare-earth metals can be substituted for lanthanum to improve cost or performance characteristics. Other materials are also added to improve performance and extend life.

AB_2 materials are based on an alloy of titanium and zirconium. These materials potentially have higher hydrogen capacity per weight than AB_5, but only within a fairly tight operating regime. For this reason, AB5 alloys are more commonly used in commercial batteries.

Hydrogen Electrodes

Nickel-hydrogen batteries can be considered nickel-metal hydride batteries without the metal hydride. In these batteries, the component called the negative electrode is actually just a reaction surface coated with a catalyst, usually platinum, on which hydrogen reacts. The actual negative electrode material is hydrogen, which is contained within the pressure vessel surrounding the cell.

Negative (NiH_2): $$\tfrac{1}{2}H_2 + OH^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} H_2O + e^- \qquad \text{Eq. 7-5}$$

The hydrogen-platinum-electrolyte interface is an intricate three-phase system that is difficult to model theoretically, and is not fully understood. In practice, however, the fact that the active material is gaseous means that the hydrogen electrode has few of the idiosyncrasies demonstrated by solid electrodes with complex crystal structures.

Iron Electrodes

Iron negative electrodes have a very complex chemistry with many intermediate products. The effective result is a two-step discharge reaction, which manifests as a two-plateau discharge characteristic. In the first discharge step, metallic iron is oxidized to iron hydroxide:

Negative (NiFe, 1st plateau): $$Fe + 2OH^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} Fe(OH)_2 + 2e^- \qquad \text{Eq. 7-6}$$

In the second step, iron hydroxide is further oxidized to iron (III) tetraoxide:

Negative (NiFe, 2nd plateau): $$3Fe(OH)_2 + 2OH^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} Fe_3O_4 + 4H_2O + e^- \qquad \text{Eq. 7-7}$$

Once again, these equations are an approximation of the complex reactions and changes occurring within the crystal matrix of the iron electrode.

Commercial iron electrodes were usually constructed in a pocket-plate process identical to that for pocket-plate nickel electrodes, but substituting iron hydroxide for nickel hydroxide. More recently, iron electrodes using sintered nickel substrates have been investigated, but not commercialized.

Recently, iron electrodes have been investigated as positive electrodes [1]. These electrodes are constructed differently from conventional iron electrodes, and follow a somewhat different chemistry, discussion of which is beyond the scope of this chapter.

Zinc Electrodes

Rechargeable zinc negative electrodes have been considered a highly desirable goal for over a century, but have proved elusive in practice. The zinc discharge and charge reaction is relatively straightforward:

Negative (NiZn): $$Zn + 2OH^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} Zn(OH)_2 + 2e^- \qquad \textbf{Eq. 7-8}$$

It should be noted, however, that zinc hydroxide is highly soluble in the caustic electrolyte. This means that a large part of the reaction product remains in solution after discharge. This leads to several phenomena that present obstacles to a practical rechargeable zinc electrode.

When the cell is recharged, the zinc is replated onto the electrode as metallic zinc, but not necessarily in the same place as where it was before discharge. The zinc has a tendency to settle to a lower part of the cell, so that the electrode after recharging is heavier on the bottom than on the top. This “shape change” effect is magnified cycle after cycle, and in time can seriously impact the performance of the cell.

In addition, zinc has a tendency to form dendrites during recharge. These are small whiskers of zinc metal that extend outward from the zinc electrode, towards the opposite electrode. Should the zinc dendrites penetrate the separator and actually touch the other electrode, the cell will short circuit, possibly causing permanent damage to the cell.

The “shape change” and dendrite problems have earned a great deal of attention. Most investigators have attempted to solve the problem through the use of additives, with varying success. These additives have included other metals, oxides of metals, and occasionally, complex organic materials.

Finally, the fact that the discharged zinc remains in solution means that it tends to migrate to the positive electrode, and sometimes clogs the pores of the nickel electrode. This ultimately reduces the capacity of the nickel electrode, and therefore of the cell.

Zinc electrodes are very susceptible to gassing, producing hydrogen during charging. This can potentially lead to pressure buildup and other hazardous situations. Even if the hydrogen is properly vented, hydrogen evolution leads to water loss, shortening the life of the cell. For this reason, additives are used to reduce hydrogen evolution. The most common additive historically has been mercury, but this is avoided nowadays to minimize environmental impact.

Zinc electrodes are constructed in several different ways. The most common way has been the pressed powder method. In this method, zinc oxide powder is combined with a small amount of polymer binder (usually PTFE) and other desired additives, and is compressed around a metal grid to produce a porous plate. The metal grid, usually nickel or nickel-plated steel, provides mechanical support and current collection. The electrode is wrapped in a nylon separator to prevent disintegration. Electro-deposition and pasting methods are also occasionally used to produce zinc electrodes.

Cell and Battery Construction

Nickel cells vary in their construction. Nickel-iron, nickel-cadmium, and nickel-zinc cells can be built either in vented or sealed configurations; nickel-hydrogen and nickel-metal hydride must be built in sealed configurations.

Nickel-electrode batteries are constructed dry from a number of electrode pairs. Each dry electrode pair consists of a positive electrode and a negative electrode with a separator between them. The type of separator used between the electrodes depends on the nature of the negative electrode. Nylon is commonly used in nickel-cadmium batteries, but this material is too porous to hydrogen for nickel-metal hydride batteries, leading to the use of polypropylene fiber composites in NiMH technologies [1]. In vented NiCd batteries, a gas barrier layer is sometimes introduced into the separator to prevent gases generated during charging from recombining within the cell.

With the exception of nickel-hydrogen, most industrial nickel-electrode cells are constructed in a prismatic form factor. Prismatic cells contain a stack of rectangular electrode pairs. Large current collectors link the electrode pairs electrically in parallel, and connect to large cell terminals which serve as the electrical interface with the outside.

When the cell package is complete, it is filled with electrolyte. The cell is then cycled a number of times to allow the electrolyte to work itself into the porous electrodes to form active mass. In vented cells, the excess liquid electrolyte is allowed to remain in the cell, and the cell is closed. Gases produced during charge are allowed to leave through a flame arrestor vent or, in some cases, a resealable valve. A port for the addition of electrolyte is also incorporated into the cell.

In sealed cells, excess electrolyte is drained after the forming cycles, leaving just enough electrolyte to wet the separator and the electrodes. The case is then sealed. The seal is rarely hermetic, however; a resealable safety vent is built into the package to release gases if the cell's internal pressure exceeds a certain level. The exception is nickel-hydrogen cells, which are truly sealed.

Nickel-cadmium and nickel-metal hydride cells are sometimes constructed in a cylindrical form factor. A cylindrical cell is constructed with a single dry electrode pair that is wound into a spiral, forming a cylindrical roll. This roll is inserted into a cylindrical container. Cylindrical cells are usually sealed types. This form is used mostly for small cells, although it is sometimes used for large NiMH cells [1].

Cells are built into batteries in a number of different ways. It is commonly done by stacking cells next to each other and connecting cell terminals in series with large busbars. There are a few batteries that are built to a monobloc design, i.e. with several cells in a single package. There are also a few designs using bipolar cells, in which the positive electrode of one cell is placed back-to-back with the negative electrode of the next cell, allowing conduction along the entire electrode surface area [1].

Performance Characteristics

Discharge and Charge Voltage

The nominal voltage for most nickel batteries, with the exception of nickel-zinc, is about 1.2 V_{dc}/cell. Charge voltage is about 1.5 V_{dc}/cell at the end of charge. The cutoff voltage during discharge depends on the application and the desired cycle life, but is usually between 0.9 and 1.1 V_{dc}/cell.

The exception to these figures is NiZn, which has a nominal voltage of about 1.5 V_{dc}/cell, with correspondingly higher typical end-of-charge and end-of-discharge voltages of 2.0 V_{dc}/cell and 1.2 V_{dc}/cell, respectively.

At low discharge rates, below about C/10, nickel batteries have fairly flat voltage profiles[10]. Figure 7-2 shows discharge voltage for pocket plate batteries as a function of state of charge and depth of discharge. The voltage initially falls rapidly, and then reaches a flat plateau until shortly before end of discharge. The voltage then falls rapidly as the active material is depleted. At higher discharge rates, the voltage profile becomes more and more sloped.

[10] Charge and discharge rates for batteries are often represented in terms of the ampere-hour capacity of the battery, C. Thus, C/10 for a 100 A-h battery is 10 A.

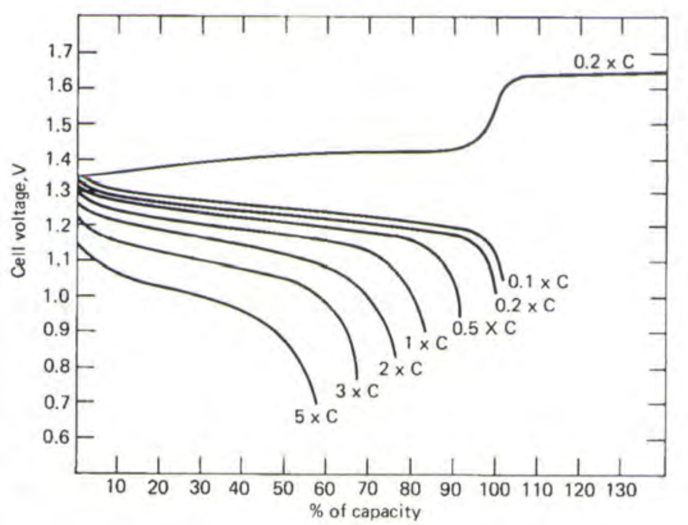

Figure 7-2
Discharge Voltage as a Function of State of Charge and Depth-of-Discharge for Pocket Plate Batteries [1]

Nickel batteries can be charged with either a constant-current or a constant-potential charge. The latter is usually used for vented systems, where the battery is designed to eject gases generated during charge. For these cells, the charge current is usually limited only by the capability of the charging equipment, and rarely by the battery hardware itself.

Efficiency

The efficiency of nickel-based batteries can vary, depending on battery design, application, and operating conditions. Round-trip DC-to-DC energy efficiencies on these batteries range from 65% to 85%, not including losses due to power conditioning and auxiliary equipment such as cooling. For NiCd batteries, DC-to-DC round-trip efficiency is about 60 to 70%.

The following effects are the most common factors in determining the efficiency of a nickel-electrode battery:

- Electrolyte concentration: Concentration can be adjusted to optimize voltaic efficiency.
- Charging procedure: Charging at high rates leads to lower voltaic efficiency. Prolonged overcharge will reduce coulombic efficiency, as the majority of overcharge input goes towards electrolysis. Some studies have shown that pulse charging can improve both voltaic and coulombic efficiency of a battery.
- Stand-time: If a battery is kept charged in an open-circuit condition, it will lose energy to self-discharge, reducing the overall efficiency when it is discharged.
- Operating temperature: Higher temperatures lead to poorer charging efficiencies.

Charge Retention

Nickel-electrode batteries lose charge somewhat more quickly than lead-acid batteries and other technologies. At room temperature, fully-charged nickel-cadmium cells lose between 2% and 5% of their charge per month. Nickel-metal hydride cells lose somewhat more. By way of comparison, lead-calcium grid lead-acid batteries lose about 1% per month. The rate of charge loss follows a decaying exponential curve, so that most of the self-discharge occurs in the days immediately after charging.

Self-discharge arises from multiple sources. The most prominent mechanism is the slow conversion of nickel oxyhydroxide into nickel hydroxide, along with corresponding reactions on the negative electrode. In NiMH and NiH_2 batteries, there is the additional mechanism of hydrogen crossing to the positive electrode and directly reacting with the nickel active material. This is especially true for NiH_2 batteries, in which the hydrogen is in direct contact with the nickel electrode.

In addition, there is the possibility of an electrical leakage current contributing to loss of charge. This can occur through separator decay, electrode damage, or through external current paths. The last is an occasional problem with vented nickel-cadmium batteries, in which potassium hydroxide settles on the top of cells, forming a current path between electrodes of adjacent cells. This is generally not a serious concern for well-maintained batteries that are regularly cleaned.

The self-discharge rate increases rapidly with temperature. This creates several issues in system design. One important effect is the sensitivity of large nickel batteries to temperature gradients. If two cells in the same battery are at different temperatures, their self-discharge rates will be different, leading to a capacity difference over time. This can lead to overcharging or reversal, potentially causing battery damage. Another important effect is thermal runaway, which is discussed below. Sealed batteries are generally much more susceptible to these occurrences than vented designs.

Effects of Temperature

While nickel-electrode batteries are generally less sensitive to temperature than other forms of batteries, temperature can have significant effects on performance and life, which can be summarized here:

- Internal resistance: Internal resistance falls with higher temperature, as electron mobility increases.
- Self-discharge: Self-discharge increases with higher temperature, as the reactions causing capacity loss on both electrodes speed up.
- Voltage: Open-circuit voltages rise at higher temperatures because of thermodynamic effects. In addition, since internal resistance is decreased at higher temperatures, overpotentials are lower for a given current rate. These effects work together during discharge to lead to higher discharge voltages at higher temperature, but work against each other during charge so that they produce little effect.

- Capacity: Charge capacity decreases when the battery is charged at higher temperature, largely as an effect of self-discharge.
- Life: Use and storage at higher temperatures generally reduces the life of the battery. In general, the rate of aging increases with higher temperatures.

Smart design can sometimes circumvent the seeming trade-offs associated with temperature. For example, it is evident that operation of a battery at cold temperatures will yield higher charge capacity (that is, ampere-hours) but lower discharge voltage, while operation at warm temperatures will yield higher discharge voltage but lower charge capacity. This would seem to be a trade-off in design. It has been shown, however, that if a battery is charged cold and then warmed just before discharge, it will yield the high charge capacity of a cold battery at the high discharge voltage of a warm battery, increasing the overall energy density.

Thermal Runaway

Many batteries, including many of the sealed nickel batteries, experience a condition called "thermal runaway." This occurs when the temperature of the battery rises above a certain critical point, as a result of high ambient temperature, high-rate discharge, or overcharge. The elevated temperature causes the self-discharge rate to accelerate. The energy lost by the cell is converted into heat, which heats the cell further. This vicious cycle continues until the battery fails, usually through separator melting or some other component failure. In some types of batteries, such as sealed nickel-metal hydride, thermal runaway can lead to rupture of the package, potentially yielding a hazardous situation.

Thermal runaway situations can be avoided by ensuring proper cooling on the battery and by avoiding very high charge currents and long periods of overcharge. Thermal runaway is rare in vented batteries except in special circumstances, such as the exposure of plates in a low electrolyte condition.

Life-Expectancy and Degradation

Nickel batteries degrade through several mechanisms. The mechanisms can be divided into two types: reversible and irreversible. Reversible mechanisms include voltage depression and passivation, while irreversible mechanisms include corrosion, component decomposition, and electrode poisoning.

Reversible Degradation

Reversible capacity loss refers to a temporary reduction in capacity in a battery, usually recoverable through some special procedure. Reversible capacity loss is not a single phenomenon, but is used to describe a number of chemical mechanisms that affect nickel-electrode batteries, including the "memory" effect, the "float" effect, and passivation.

The so-called "memory effect" is commonly cited as a cause of reversible capacity loss, but is actually quite rare. This effect is seen when some types of nickel-electrode cells are repeatedly cycled at shallow depths-of-discharge. As the number of cycles increases, there is a gradual reduction in both voltage and capacity as the cell at the end of the shallow cycle. A full discharge curve of a cell exhibiting voltage depression exhibits an inflection point at the point where the shallow discharges were stopped, seeming to indicate that the cell somehow "remembers" where the end of discharge took place. This inflection point vanishes when the cell is fully discharged and then recharged.

Figure 7-3 shows the effects of repetitive cycling on a sealed nickel-cadmium cell. In curve 1, the cell shows full capacity. With repetitive shallow cycling (curves 2), the capacity slowly decreases because of a sagging voltage curve. Curve 3 shows that a full discharge demonstrates an inflection point where the cell "remembers" the cut-off voltage of the shallow discharges. Finally, curves 4 and 5 show gradual increase in capacity after the full discharge.

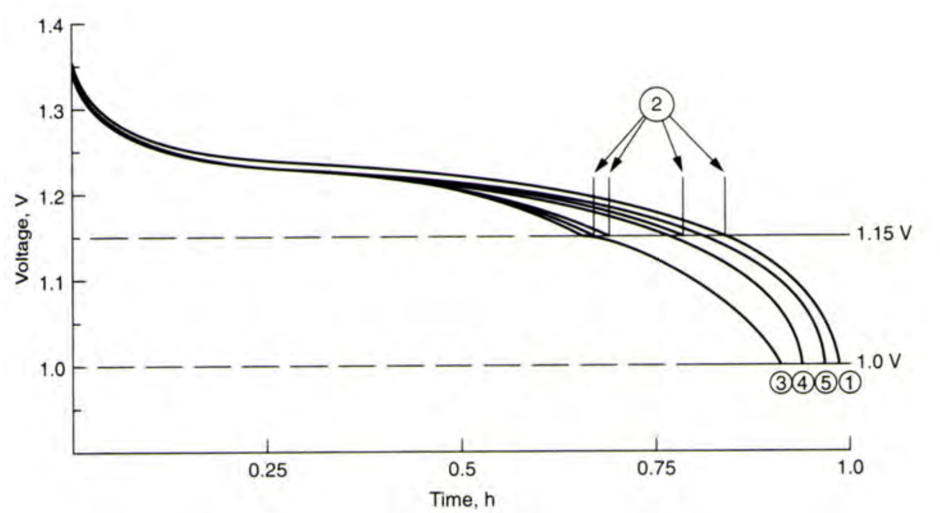

Figure 7-3
The "Memory Effect" in a Sealed Nickel-Cadmium Cell [1]

Despite its fame, the memory effect is actually very rare, and is seen mostly in lightly-cycled sealed nickel-cadmium batteries with sintered electrodes. Industrial nickel-electrode batteries used in the utility industry do not exhibit the memory effect. Nonetheless, the term is sometimes used informally to describe temporary capacity loss of any sort.

More common among industrial batteries is the "float effect," which is a form of reversible capacity loss that occurs after long periods of sustained float charge, and is often mistaken for the "memory effect." This form of voltage depression causes watt-hour capacity to decrease somewhat after long periods of float charge, although ampere-hour capacity sometimes actually increases. This effect is difficult to avoid, and is usually handled by sizing the battery on the basis of capacity measured after a long float charge.

Passivation is a term that describes a condition during which the charge and discharge capabilities of an electrode are temporarily impaired. This shows up in the performance of the cell as a significant voltage drop during discharge or as an overvoltage during charge. Passivation occurs with some forms of cadmium and zinc electrodes, and can be caused by a wide range of phenomena, from electrolyte stratification to the formation of a barrier layer within the electrode.

Most forms of reversible capacity loss can be eliminated by completely discharging the battery and then recharging it, thereby cycling the active material. In severe cases, a second or third full cycle may be required to restore performance. Even when such cycling is not feasible, voltage depression is relatively simple to account for when sizing the battery, and should not pose problems in well-designed systems.

Irreversible Degradation

The dominant degradation modes for batteries differ with application as well as the type and design of the battery. From an application standpoint, the operating temperature of the system and the number and the depth-of-discharge of cycles are the most important factors in determining the dominant mode.

In nickel-cadmium batteries, there are several possible degradation and failure modes:

- Nickel-electrode corrosion, resulting in increased internal resistance in the electrode, and possibly cracking and buckling of plates. This is often the cause of failure in sealed NiCd systems, where the expanding nickel electrode squeezes out the electrolyte from the separator.
- Decomposition of organic materials in cell into carbonates, resulting in increased resistance in the electrolyte. The organic materials in the cell are the separator, the gas barrier layer, and graphite in the two electrodes. This is especially prevalent in pocket plate designs, where the graphite is the main source of carbonates. Modern separators and gas barriers are designed to be stable in the electrolyte.
- Formation of dendrites on the negative electrode, which can penetrate the separator. This occurs only with sintered plate designs.
- Gas barrier failure, which allows gases in a vented cell to recombine within the cell itself. This leads to heating, larger self-discharge rates, and eventually short-circuiting. This failure mode only affects vented cells, since sealed cells don’t have gas barriers.
- Electrode poisoning, especially poisoning of the positive electrode by iron migrating from the negative electrode. This applies largely to pocket plate designs.

Some of these mechanisms, such as corrosion and electrode poisoning, are strongly connected with frequency and depth of discharge cycles and the charging profile. regardless of the battery’s age. Other mechanisms, such as organic material decomposition, are more dependent on the age and temperature of the battery, regardless of the number of cycles it experiences.

Life Expectancy

The life for nickel batteries is described both in terms of calendar life (years) and cycle life (number and depth of cycles). The service life will be limited by either the number of years before replacement, or by the number of cycles that the battery undergoes, depending on the more demanding requirement.

Both calendar life and cycle life depend on the design of the battery and the application in which it is used. Cycle life varies somewhat between the different types of batteries. Pocket plate industrial nickel-cadmium batteries are capable of roughly 800 to 1000 cycles when cycled at 80% depth-of-discharge. Sintered plate industrial nickel-cadmium batteries are capable of around 3500 cycles in the same regime. Both types are capable of a much larger number of cycles at lower DOD, up to about 50,000 cycles at 10% DOD (See Figure 7-4). Sealed nickel-cadmium batteries have somewhat shorter cycle life.

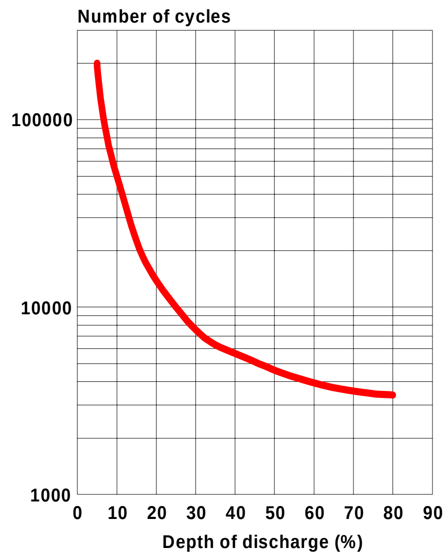

Figure 7-4
Cycle Life as a Function of Depth-of-Discharge for a Sintered/PBE Nickel-Cadmium Cell (Courtesy Saft)

Nickel-metal hydride and nickel-hydrogen batteries have cycle life capabilities roughly as good as vented nickel-cadmium. Nickel-iron batteries also cycle well, depending on the construction of the batteries. Nickel-zinc batteries have somewhat shorter cycle lives, with typically less than 1000 cycles.

Nickel batteries are usually capable of long calendar life where the number of cycles is small. Flooded nickel-cadmium batteries are typically rated to last 10 to 15 years in lightly cycled applications, although actual life can be much longer. Most sealed batteries, such as sealed nickel-metal hydride, have somewhat shorter lives. Nickel-iron batteries have very long service lives, and have been known to operate over 25 years. Calendar life is heavily dependent on the average temperature at which a battery is operated. At high temperatures, calendar life will be shortened. A common rule of thumb is that calendar life of nickel-cadmium batteries falls by 20% with every 10ºC increase in operating temperature.

Safety and Environmental Hazards

The safety issues with nickel batteries are those associated with most other battery systems. The batteries contain caustic materials which, if spilled, can present a hazard to personnel. Other materials in batteries can also pose a hazard if ingested.

All nickel batteries produce a certain amount of hydrogen and oxygen during charging due to electrolysis of the aqueous electrolyte. In sealed systems, the hydrogen and oxygen usually recombine inside the cell and do not pose a hazard to personnel. If sealed cells are charged at a very high rate, the gassing rate may outpace the rate of recombination. This will lead to pressure build-up within the cell. In most cells, a safety valve is designed into the packaging to relieve pressure before the packaging ruptures. In such cases, the cell is often ruined but hazardous conditions are usually averted.

In vented systems, the hydrogen and oxygen produced during charge are vented to the atmosphere. Vented systems must be placed in a well-ventilated location where hydrogen is not allowed to accumulate.

Nickel batteries contain transition metals which can become contaminants in soil and ground water. This is true of iron, zinc, and the metal components of metal hydrides, as well as of nickel itself.

Cadmium is a particularly toxic material that, if not properly handled, can present a serious environmental hazard. Special disposal means are required to handle cadmium. The cadmium material is often collected and recycled for use in future batteries.

Nickel cells in general are highly recyclable, and organizations exist in most countries to collect and recycle the active materials in a safe, effective manner, reducing waste arising from the disposal of these batteries.

System Design

Although nickel-electrode cells operate at a relatively low voltage, it is possible to produce systems with higher voltage by electrically linking cells in series. Cells are sometimes packaged together in the same case and sold as a unit, called a *monobloc* design.

Individual cells are also limited in terms of discharge current. There is a maximum discharge current that a cell of a certain design can produce while maintaining a given voltage. This limitation can also be overcome by electrically linking cells (or series strings of cells) in parallel. In this way, systems can be designed to provide a large current at a reasonably high voltage.

As the number of cells in a system increases, the system becomes more complex and the number of points of possible failures also increases. For this reason, very high-voltage battery systems are not practical. The limit for high-voltage strings is generally accepted to lie between 2000 and 10000 V_{dc}. The largest series strings built to date are the 5000 V_{dc} strings built for the Golden Valley Electrical Association BESS.

The design of batteries for stationary applications requires trade-offs between a number of factors. These batteries are usually designed to minimize floor space without compromising electrical, thermal and maintenance considerations. The cells are typically mounted on racks which allow easy accessibility to all cells for inspection, maintenance, and replacement when necessary. The assembly is housed inside a building or in a weatherproof enclosure.

Figure 7-5
GVEA BESS NiCd Battery (Courtesy GVEA)

The cells are connected electrically using large cables or bus bars, and are arranged in a configuration so that the total length of the current path through the series string is minimized. These features ensure that the internal resistance of the system is kept as low as possible.

The design must provide a thermal path for the heat produced by the battery during charge and discharge. In most cases, active cooling such as air-conditioning is used to keep the battery cool. In locations subject to cold weather, heating systems may be required to prevent electrolyte freezing.

There must also be safety precautions for hydrogen and other gases which may be produced during charging. The battery area should always be well-ventilated, and a hydrogen sensor should be installed to detect hydrogen accumulation before it reaches a hazardous level.

In some instances, a control system is added to the battery to ensure that it is operating normally. This system may be as simple as a monitoring system that signals abnormal conditions or may be a complex active system that controls operations to prevent problems before they occur.

Power conditioning is often used with battery systems to ensure that the output power meets quality required by the application. In DC applications in which the required voltage range is very narrow, a DC-DC converter may be used to compensate for the change in voltage over the course of discharge. An inverter is used when AC output power is required. Whenever power conditioning is used, the voltage, current, and power capabilities of the power conditioning system, as well as its input requirements, must be considered in developing the system. The system designer must also consider that thermal calculations must also include dissipation from the power electronics.

These auxiliary systems may add significant costs to the system, as well as introducing further complexity and vulnerability to failure.

Operation and Maintenance

Operation and maintenance of nickel-electrode batteries varies with the design. Sealed batteries require relatively little maintenance, limited to float or trickle charging, regular cleaning, and perhaps an occasional reconditioning. Vented batteries require the additional maintenance associated with the addition of water.

Float Charging or Trickle Charging

Float charging, in which a constant voltage is applied to a fully-charged battery to produce a small charging current, is used to counteract self-discharge in the battery. This ensures that the battery is fully charged when discharge is necessary. *Trickle charging* performs essentially the same role as float charging, but with a small constant current instead of a constant voltage. The two terms are often used interchangeably.

The energy delivered in the float charge is partly dissipated as heat. Another part of the energy goes towards the production of hydrogen and oxygen through electrolysis of water. In sealed batteries, the hydrogen and oxygen recombine into water, releasing energy as heat; the net effect is that virtually all float charge energy in sealed batteries ends up as heat.

In vented batteries, the evolved gases are vented to the atmosphere, carrying some energy with them. The net effect is that vented batteries do not typically generate as much heat during float charge as sealed batteries do.

The float charging voltage is an important factor in operation. If the float charging voltage is too low, the charging current will not be sufficient to prevent self-discharge, leaving the battery less than fully charged. If the float charging voltage is too high, the thermal generation, and rate of water loss in vented batteries, will be unacceptably high.

Reconditioning

Nickel-electrode batteries are sometimes fully discharged and then recharged to mitigate or eliminate the effects of voltage depression and passivation. This procedure is often called *reconditioning*. In some applications, especially those where high discharge voltage and high capacity are very important, reconditioning is performed on a regular basis, often two to four times a year. This procedure also allows the operator to measure the capacity of the battery.

In most applications, however, reconditioning is unnecessary. Reconditioning can even have a deleterious effect if the procedure is done incorrectly. It can also shorten the cycle life of a system by subjecting the battery to unnecessary deep cycles.

Water Addition

Vented batteries require regular maintenance in the form of *watering*. In this operation, distilled water is added to each individual cell to replace water lost through evaporation and electrolysis. The frequency of watering varies with the application, from several times a year for batteries cycling often, to once in two years for more batteries with lighter load factors. More frequent watering is required in applications with frequent cycling and at higher operating temperatures. In some cases, water addition is automated; more commonly, it is a manual operation.

Watering is not necessary for sealed batteries. Since water addition can inhibit recombination mechanisms and produce potentially dangerous situations, these types of batteries are built without ports through which water can be added.

Technology Status

Notable Vendors and Developers

Acme Electric Corporation (www.acmeelec.com)

Acme Aerospace Company, a subsidiary of Acme Electric Corporation, is developing maintenance-free fiber plate nickel-cadmium batteries for the aerospace market. While these batteries are generally designed to replace flooded NiCd used for starting aircraft engines, similar batteries may be used in the future in stationary applications.

Alcad (www.alcad.com)

Alcad, a Swedish battery company, designs and manufactures batteries for a variety of industrial applications, focusing on nickel-cadmium and some forms of lead-acid batteries (such as Planté types). They are also deeply involved in the recycling of nickel-cadmium batteries. Alcad has marketed nickel-cadmium in a variety of utility applications. They have been particularly active in advocating nickel-cadmium for use in substation batteries in hotter and colder climates, where the performance of lead-acid batteries is sometimes impaired.

Eagle-Picher Technologies (www.epcorp.com)

Eagle-Picher Technologies is well known as a manufacturer of a variety of specialty batteries, including nickel-cadmium and nickel-hydrogen batteries, usually for military and aerospace applications. They also have an extensive line of low-power nickel-cadmium and nickel-metal hydride products for applications such as toys and power tools. The company has also been involved with numerous technology development efforts with nickel-iron, nickel-metal hydride, and nickel-zinc batteries.

ElectroEnergy, Inc. (www.electroenergyinc.com)

ElectroEnergy, Inc., based in Danbury, CT, is a manufacturer of high-rate nickel-metal hydride batteries. The company's most well-known product is a design using a flat bipolar cell that allows high current densities. In a bipolar design, each cell consists of a single pair of electrodes, with a separator containing electrolyte in between them. The positive electrode of each cell is in direct contact with the negative electrode of the next cell, without an intermediate busbar. This approach results in much smaller internal resistance, as well as the elimination of conventional terminals, tabs, current collectors, and cell packaging.

Electroenergy has recently sought to enter the utility market, and is marketing their bipolar system for use in a variety of utility energy storage applications, including UPS, and load shifting.

EnerSys (www.enersysinc.com)

EnerSys, Inc., a major manufacturer of industrial batteries, sells pocket plate nickel-cadmium batteries under the Varta name. Varta AG, a German manufacturer of batteries, was an important developer of the pocket plate nickel-cadmium battery during World War II. The battery was marketed for industrial applications after the war, particularly substation batteries.

The acquisition of Varta's nickel-cadmium products by EnerSys is an illustration of the frenetic merger and acquisition activity in the battery industry in the 1990s. In 1995, Varta's industrial battery group, including the NiCd line, was sold to the British conglomerate BTR plc. BTR also owned Hawker, an American manufacturer of industrial batteries, and the two groups were combined to form Hawker Energy Products. BTR plc merged with Siebe plc in 1999 to form Invensys plc. In 2002, EnerSys purchased the Energy Storage Products group of Invensys plc, including Hawker Energy Products.

EnerSys is itself is the former industrial battery manufacturing division of Exide Corporation. Exide sold its industrial battery operations, as well as the rights to the use of the Exide name in that market, to Yuasa Corporation in 1991. The resulting company was named Yuasa-Exide, which changed its name to EnerSys in 2000.

Understandably, EnerSys continues to sell the TP line of large pocket plate NiCd cells under the Varta name.

Evercel Corporation (www.evercel.com)

The portion of the former Energy Research Company that researched advanced batteries was spun off in 1999 to form Evercel Corporation. The company, based in Danbury, CT, is the best-known developer of nickel-zinc technology. In 2001, the company initiated a joint venture with Three Circles Battery Co. Ltd, of Xiamen, China, to mass produce its product. Evercel bought the remainder of the company from Three Circles in February 2003, making the subsidiary wholly-owned by Evercel.

Evercel has released products primarily aimed at motive power applications such as electric scooters. The company has also developed a number of products that are suitable for stationary applications. The company's technology is based on an innovative use of roll-bonded nickel and zinc electrodes. In this method, the electrodes are produced from a mix of active material, a solvent, and a PTFE binder, in a process similar to that used for plastic-bonded cadmium electrodes.

Hoppecke Batterien GmbH (www.hoppecke.com)

Hoppecke is a German battery company founded in 1927 in Brilon, Germany by Carl Zoellner. The company manufactures batteries of several chemistries, including lead-acid, nickel-cadmium, and nickel-metal hydride, for a large variety of applications. The company is best known in the nickel-cadmium field for its extensive research into nickel-fiber electrodes. The FNC vented nickel-cadmium line uses nickel-fiber electrodes, and is designed for stationary reserve power applications.

Johnson Controls, Inc. (www.johnsoncontrols.com)

Johnson Controls, Inc. (JCI) is a major manufacturer of lead-acid batteries, mostly for transportation applications. The company recently purchased the automotive battery line from Varta Batteries, AG, which includes lines in large nickel-metal hydride and lithium ion batteries. These products are generally aimed at the hybrid electric vehicle market, but the company has expressed interest in developing both NiMH and lithium ion products for the stationary market where the applications will be similar to those used in HEV.

Marathon Power Technologies Company (www.mptc.com)

Marathon Power Technologies traces its lineage to Sonotone Corporation, the earliest developer of nickel-cadmium batteries in the United States. Marathon, based in Waco, Texas, has a line of vented sintered-plate nickel-cadmium batteries for the aircraft industry, particularly for military applications. (Marathon Power Technologies should not be mistaken for the Marathon line of VRLA batteries produced by GNB Industrial Power.)

ECD Ovonics, Inc. (www.ovonics.com)

ECD Ovonics was founded in the 1960s to commercialize a variety of technologies invented by its founder, Stanford Ovshinsky. The company was heavily involved in developing the first nickel-metal hydride batteries, and continues to be a leading developer of NiMH technology. The company is involved in a number of stationary applications, including the use of NiMH batteries with solar power systems.

Panasonic (www.panasonic.com)

Panasonic, a division of Matsushita Electric, is a manufacturer and distributor of several lines of small NiCd and NiMH batteries for portable electronics and power tools applications. Panasonic has also worked on developing larger scale products, particularly by stacking a large number of smaller cells to produce higher voltages. These products are principally targeted at electric vehicle and hybrid electric vehicle applications. For example, Panasonic has developed the NiMH battery used in the Toyota Prius hybrid electric vehicle.

Saft (www.saftbatteries.com)

Based in Bagnolet, France, Saft is a major manufacturer of specialty batteries for a variety of markets, including stationary, transportation, industrial, and military applications. Saft is a particularly important supplier of industrial and stationary nickel-cadmium batteries. Saft has several important stationary NiCd lines, including the SBL, SBM, and SBH series of flooded pocket plate nickel-cadmium batteries, as well as the SPL, SLM and SPH series which are low-maintenance flooded products designed as VRLA replacements. The company also produces flooded aircraft nickel-cadmium batteries, which can be used in high-rate applications such as power quality. The company plans to release a power quality product using these batteries in the near future.

Tudor (www.bateriastudor.com)

Sociedad Española del Acumulador Tudor, SA is a Spanish manufacturer of lead-acid and nickel-cadmium batteries for automotive and stationary applications. In 1994, the company was purchased by Exide Technologies. Tudor’s nickel-cadmium line, sold under the Emisa trademark, consists of a variety of pocket plate and nickel-fiber designs for stationary applications, particularly reserve power and substation battery power. In April 2003, Exide Technologies sold Emisa (with other European nickel-cadmium assets) to Saft.

Varta (www.varta.com)

Varta, a German manufacturer of consumer, industrial, and automotive batteries, began as the firm Büsche and Müller in Hagen, Germany. The company was well-known for its presence in most major battery markets, including consumer, automotive, and industrial batteries. The company has recently undergone some restructuring, including the sale of the consumer division to Rayovac and the automotive division to Johnson Controls. The industrial battery line, including the nickel-cadmium TP series, is now owned by EnerSys, although still produced under the Varta name. Until recently, Varta was also developing large NiMH batteries for the hybrid electric vehicle market, but this technology was sold to Johnson Controls with the Varta Automotive Batteries group.

Yuasa (www.yuasa.co.jp)

Founded in 1913, Yuasa is a major manufacturer of batteries in Japan, with products in the SLI, stationary, and industrial deep-cycle areas. In July 2003, the company agreed to merge with Japan Storage Battery to form GS Yuasa Corporation. The company produces a number of small cell sealed nickel-cadmium and nickel-metal hydride batteries, largely for portable applications.

Development Projects

Golden Valley Electric Authority (Fairbanks, AK)

The most significant application of nickel-electrode cells in the utility industry is the Golden Valley Electric Authority (GVEA) Battery Energy Storage System (BESS) in Fairbanks, Alaska.

The GVEA BESS was commissioned in September, 2003 to provide standby power during power shortfall. Fairbanks is supplied electricity from power plants near Anchorage through the Northern Intertie. Before the BESS was installed, occasional problems with the Intertie or power plants in the south required load shedding in the Fairbanks area, a serious problem in a locale where temperatures can fall below -51 ºC in the winter. The BESS is designed to provide power for a short period of time, up to 15 minutes, until backup generation comes on-line. Such events are expected about 30 times a year. In addition, the BESS also provides spinning reserve capability, reducing fuel costs associated with conventional backup generation. The primary design and controls for the BESS was performed by ABB, and Saft supplied the nickel-cadmium battery.

The system was originally sized for 6 strings, delivering 40 MW_{ac} for 15 minutes, with 15% overload capability for a shorter duration. The present system comprises 4 strings, and is sized to deliver 27 MW_{ac} for 15 minutes. The capacity of the system is sized for 12 years; the initial power and energy capacity is somewhat better than the sized capacity. The facility is also designed so that four additional strings can be installed in the future, should they be required.

The nickel-cadmium battery is composed of 13,760 Saft SBH 920 pocket plate nickel-cadmium cells, arranged in 4 strings of 3,440 cells each, with a nominal voltage of 5000 V_{dc} and a storage capacity of 3680 Ah. The 5000 V_{dc} string is center-grounded, i.e. the positive end of the string is at +2500 V_{dc} and the negative end is at -2500 V_{dc}. Each string can be divided electrically into 8 groupings, each with an open-circuit voltage of about 600 V_{dc}. This arrangement allows the high-voltage string to be broken into several strings of lower voltage for maintenance purposes. The relatively small number of discharges ensures that the cycle life associated with the pocket plate construction will be sufficient for the application [3].

A string with such a high voltage is somewhat unusual among BESS units because of concerns with high voltage and because of reliability issues. In the GVEA instance, these concerns have been addressed through design. First, the construction of the Saft cell, which uses welded polypropylene cases, reduces the chance of voltage breakdown between cell connectors and the cell case. Deposited potassium hydroxide electrolyte that escapes from the cell during gassing forms potassium carbonate on contact with the air, and therefore is far less likely to form a current path than the sulfuric acid used in lead-acid cells. The current leakage from cells is also monitored over time, and out-of-tolerance conditions are reported immediately to the control system.

Reliability is sometimes an issue with high-voltage strings, since open-circuit failure of a single cell would result in the loss of the entire string. In the case of this design, open-circuit failure would require that a cell case rupture, the electrolyte drain out, and the cell completely dry out. Each cell is constructed from six separate electrolyte compartments, with communicating holes placed about mid-way from the bottom. Failure would not occur unless all six compartments were simultaneously ruptured.

Although such failure is highly unlikely, a failure mode of this type would be quickly detected and the string would be taken off-line. A failure of this type would result in a higher internal resistance in the string, as well as a jump in voltage during charge. Each string contains electronics which detect continually detects differences in internal resistance and voltage during the float charge period, and which cuts off power to the string in the event that a dangerous condition is detected [30].

Mechanically, each of the groupings is built from 43 ten-cell modules, for a total of 344 modules per string. These modules are mechanical and electrical units designed to minimize the number of electrical and mechanical connections that must be made on-site. Each module has a footprint of about 10 ft^2 and weighs about 1 ton. Each module can be lifted as a unit and placed on a rack.

The module system is also designed to simplify maintenance, as water filling is done at the module level. The watering process is manual, but is a relatively infrequent process, to be performed once in two years. Ten spare modules are kept on float charge at the facility to replace modules in the event of a malfunction.

The modules are arranged on 5-tier racks with 9 bays on each tier; a 43-module grouping fits on one rack, with two bays left over for switching. The use of 5-tier racks minimizes the floor space required for the battery system [3].

The PCS for the GVEA BESS was designed and constructed by ABB using IGCT technology. The system is water-cooled, and is controlled by ABB's programmable high-speed controller (PHSC). [28]

The GVEA BESS went into initial operation in September, 2003, and projects functional capacity of 27 MW_{ac} for 15 minutes by December 2003 [29].

T&D System Energy Storage System Applications

Select Applications for Nickel-Cadmium Energy Storage Systems

This section presents the select applications for which nickel-cadmium batteries are suited and describes the key features of nickel-cadmium systems when configured to meet the select application requirements. This applications analysis has been restricted to nickel-cadmium because these are the only nickel electrode systems widely available for utility applications today. While large nickel-metal hydride products are available, these products are generally at a relatively early stage of development and have not shown clear advantages over flooded nickel-cadmium products.

Screening economic analyses have shown that nickel-cadmium systems are potentially competitive for some of the single function applications, as well as two of the combined function applications, which are described in detail in Chapter 3. The following list briefly summarizes all of the Chapter 3 applications, with a reiteration of the key application requirements. Those for which nickel-cadmium systems are best suited are enclosed by borders.

Single Function Applications

Application A: Grid Angular Stability (GAS) – mitigation of power oscillations by injection and absorption of real power at periods of 1 to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 20 oscillatory cycles, cumulatively equivalent to a full power discharge (FPD) of 1 second duration; 1 event per day; 10 events per year. Valued at the cost of alternative solutions.

Application B: Grid Voltage Stability (GVS) – mitigation of degraded voltage by additional reactive power plus injection of real power for durations up to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 1 second FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application C: Grid Frequency Excursion Suppression (GFS) – “prompt” spinning reserve (or load) for mitigating load-generation imbalance. Requires energy storage to discharge real power for durations up to 30 minutes. The reference duty cycle for analysis is standby for infrequent events characterized by 15-minute FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application D: Regulation Control (RC) – system frequency regulation in concert with load following. The reference duty cycle for analysis is characterized by continuous cycles equivalent to 7.5-minute FPD and charge cycle (triangular waveform), 2 cycles per hour deployed with 10 minutes advance notice. Valued at market rates.

Application E: Spinning Reserve (SR) – reserve power for at least 2 hours with 10 minute notice. The reference duty cycle for analysis is standby for infrequent events characterized by 2-hour FPD, 1 event per day, 10 events per year. Valued at market rates.

Application F: Short Duration Power Quality (SPQ) – capability to mitigate voltage sags (e.g., recloser events). The reference duty cycle for analysis is standby for infrequent events characterized by 2 seconds FPD, 1 event per hour, 5 events per day, 100 events per year. Valued at the cost of alternative solutions.

Application G: Long Duration Power Quality (LPQ) – SPQ, plus capability to provide several hours reserve power. The reference duty cycle for analysis is standby for infrequent events characterized by SPQ plus standby for 4 hours FPD, 1 event per year. Valued at the cost of alternative solutions.

Application H: 3-hr Load Shifting (LS3) – shifting 3 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 3-hour FPD, 1 event per day, 60 events per year. Valued at market rates.

Application I: 10-hr Load Shifting (LS10) – shifting 10 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 10-hour FPD, 1 event per day, 250 events per year. Valued at market rates.

Combined Function Applications (In the Order Noted)

Application C1: Combined Applications C, A, B, D (GFS + GAS + GVS + RC)

Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR)

Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR)

Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR)

Application C5: Combined Applications I, D, E (LS10 + RC + SR)

Nickel-Cadmium Energy Storage System Compliance With Application Requirements

The nickel-cadmium performance parameters discussed above were used to develop approximate sizes and operational parameters for systems meeting the application requirements for the selected applications described in the previous section. Key factors in sizing nickel-cadmium systems include:

- Duration of the discharge. For applications requiring very short discharge, a small high-rate sintered-plate battery would be appropriate. A cell with a higher ampere-hour rating would be better suited for longer discharges.
- Depth of discharge. Sintered-plate nickel-cadmium batteries are most appropriate when a large number of cycles is required. Pocket plate batteries may be used when fewer cycles are required.
- Selection of the type of PCS and pulse factor (which determines the minimum discharge voltage and therefore the PCS cost as described in Section 5).
- State-of-charge management to ensure that the required power and energy are accessible and that the battery is appropriately recharged.
- Thermal management to ensure that cell temperatures are maintained within the acceptable range and that the rate of heat loss is appropriate to the application.

- Cycle life management to ensure that the system is operated within the service life of equipment, which is especially important for combined function, high cycle applications such as load shifting with regulation control.

Performance aspects of nickel-cadmium energy storage systems for the selected applications are described below and summarized inTable 7-1. The reference power for all applications in 10 MW_{ac}. In these examples, representative nickel-cadmium products have been selected and sized for the application at hand. The selected product is appropriate for the particular application on the basis of technical and economic criteria. This does not mean, however, that other products could not also perform the same function.

- Application A: Grid Angular Instability (GAS) – This application requires that the system continuously detect and mitigate power oscillations. Oscillations require that the system alternately inject and absorb full power, for an equivalent of a 1 sec full power discharge. The energy storage would be composed of 15 Saft Power Quality Battery Systems, each composed of a string of aircraft NiCd batteries, operating between about 400 and 850 V_{dc}. This system would be connected to a Type III PCS with a pulse factor of 5. During most of the year, the system would be at standby, with an efficiency of 98%. Because of the relatively light load profile, the lifetime of the system is estimated to be limited by calendar life to about 15 years.
- Application C: Grid Frequency Stability (GFS) – This application requires that the system continuously detect and mitigate infrequent frequency excursions, for up to 10 events per year, requiring a discharge of about 15 minutes each. In this relatively long-duration application energy storage would be composed of large series strings of nickel-cadmium batteries. Two (2) strings, each composed of 2200 Saft Pocket Plate SBH 920 cells linked in series, would be connected to a Type I PCS. The system would be mounted on 5-tier racks. During most of the year, the system would be at standby, with an efficiency of 98%. The lifetime of this system would be dominated by calendar life rather than cycle life, so that the system is expected to last 15 years.
- Application F: Short Duration Power Quality (SPQ) – This application requires that the system continuously detect and mitigate infrequent PQ events lasting 5 seconds. The energy storage would be composed of 15 Saft Power Quality Battery Systems, each composed of a string of aircraft NiCd batteries, operating between about 400 and 850 V_{dc}. This system would be connected to a Type III PCS with a pulse factor of 5. During most of the year, the system would be at standby, with an efficiency of 98%. Because of the relatively light load profile, the lifetime of the system is estimated to be limited by calendar life to about 15 years.
- Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC) – This application requires that the system continuously detect and mitigate infrequent GFS, GAS, and GVS events lasting to 15 minutes for GFS. The system will also provide RC functions for 2 hours per day, 23 days per year. Two (2) strings, each composed of 2200 Saft Pocket Plate SBH 920 cells linked in series, would be connected to a Type I PCS. The system would be mounted on 5-tier racks. During most of the year, the system would be at standby, with an efficiency of 97.9%. The lifetime of this system would be dominated by calendar life rather than cycle life, so that the system is expected to last 15 years.

Table 7-1
Nickel-Cadmium System Compliance With Application Requirements

Applications	Single Function			Combined Function	
	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	App C: GFS -- 15 min FPD per cycle, 10 events/yr, 1 event/d	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr	App C1: GFS +GAS + GVS + RC	App C3: SPQ + LS3 + RC + SR
Energy Storage Selection					
Type of Product	Saft Power Quality Battery 235 kW	Saft Pocket Plate SBH 920, 220-Module String	Saft Power Quality Battery 235 kW	Saft Pocket Plate SBH 920, 220-Module String	Saft Sintered Plate SPH 320, 74-Module String
Number of Strings	45	2	45	2	9
Pulse Factor	5.0	1.0	5.0	1.0	5.0
Max Charge Voltage	837	3,344	837	3,344	3,374
Min Discharge Voltage	432	2,200	432	2,200	2,220
Maximum DOD, %	80%	80%	80%	80%	80%
Cumulative Cycle Fraction	0%	19%	3%	100%	90%
Replacement Interval, yr	15	15	15	15	10
PCS Selection					
PCS Type (Chapter 5)	III	I	III	I	III
Duty Cycles					
Grid Support or Power Quality (GS or PQ)					
Power, MW	10	10	10	10	10
Event Duration, Hr	0.000	0.25	0.001	0.25	0.001
Load Shifting (LS)					
Power, MW					1.8
Load Shift Energy, MWh/yr					321
Load Shift Losses, MWh/yr					153
Cycle Life Fraction					17%
Regulation Control (RC)					
Power, MW				10.0	2.2
Hours per day, hr				2	20
Days per year, days				24	350
RC, MW-Hours/yr				480	15,492
RC Losses, MWh/yr				57	1,849
Cycle Life Fraction				84%	70%
Spinning Reserve (SR)					
Power, MW					2.2
SR, MW-Hours					2,867
SR Losses, MWh/yr					21
Cycle Life Fraction					2.67%
Summary System Data					
Standby Hours per Year	8,760	8,734	8,754	8,686	1,320
System Net Efficiency, %	98.0%	98.0%	98.0%	97.9%	97.4%
Energy Storage Standby Efficiency, %	100.0%	100.0%	100.0%	100.0%	100.0%
PCS Standby Efficiency, %	98.0%	98.0%	98.0%	98.0%	99.7%
System Footprint, MW/sqft (MW/m^2)	0.0068 (0.073)	0.0045 (0.0483)	0.0068 (0.073)	0.0045 (0.0483)	0.0037 (0.0397)
Energy Storage Footprint, MW/sqft (MW/m^2)	0.0516 (0.5556)	0.0106 (0.1137)	0.0516 (0.5556)	0.0106 (0.1137)	0.007 (0.0751)

Note: System net efficiency includes losses for energy conversion and system standby expressed on an annual basis, i.e., one minus inefficiency, where inefficiency equals the ratio of annual energy losses to the product of system rated

- Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR) – This application requires that the system continuously detect and mitigate infrequent SPQ events lasting to 5 seconds. In addition, the system will provide load shifting services at 1.8 MW_{ac} for 3 hours per day for 60 days a year. The regular deep-cycling of this application requires that we use a sintered-plate nickel-cadmium cell. Nine (9) strings, each composed of 2220 Saft Sintered Plate SPH 320 cells linked in series, would be connected to a Type III PCS with a pulse factor of 5. The system will also provide RC at 2.2 MW_{ac} for 20 hours per day for 350 days per year, and SR for the remaining 1,296 hours per year. The system would be mounted on 5-tier racks. The system would have a net efficiency of 97.4%. The lifetime of this system would be affected by both calendar life and cycle life; the system can be expected to last 10 years.

Benefit and Cost Analyses

Nickel-Cadmium Energy Storage Pricing and Integrated System Costs

Nickel-cadmium batteries are mature, well-established products with commodity pricing. Changes over time will be dependent largely on fluctuations in the commodity prices of nickel and cadmium. The pricing of batteries is often dependent on the number of products bought at once. Large orders can often bring significant discounts on the price of batteries.

For the Handbook's specified deployment date of 2006 and rating of 10MW_{ac}, the prices are based on manufacturers' quotes from 2003 for bulk quantities of batteries, including interconnection hardware and racks. Replacement modules over the assumed 20 year project life are assumed to follow the same cost structure.

Nickel-Cadmium Product	2003 Prices
Saft Power Quality Battery System	$81,000
Saft SBH 920 Battery 10-Cell Module	$7,780
Saft SBH 920 220-Module String	$1,712,000
Saft SPH 320 Battery, 30-cell Module	$9,300
Saft SPH 320 74-Module String	$688,000

The related scope of supply for these products includes the cells themselves, the cell interconnection hardware, and mounting racks. The Power Quality systems also include DC circuit breakers.

The cost of integrated nickel-cadmium systems is obtained by combining the cost of the nickel-cadmium product scope of supply with the appropriate PCS and BOP costs as described in Chapter 5. The PCS and BOP costs shown in Table 7-2 are based on the methodology described in Chapter 5. The BOP scope of supply consists of grid connection at the point of common coupling, land and improvements (e.g., access, services, etc.) and is based on a nominal cost of $\$100/kW_{ac}$. The nickel-cadmium systems described here would be located in interior space with environmental control. The cost for this space is included at $100/sqft. In addition, where 5-tier racks are used, space costs are increased by 20% to account for the requirement of a multi-story building.

Table 7-2
Capital and Operating Costs for Nickel-Cadmium Systems

Applications	Single Function			Combined Function	
	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	App C: GFS -- 15 min FPD per cycle, 10 events/yr, 1 event/d	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr	App C1: GFS +GAS + GVS + RC	App C3: SPQ + LS3 + RC + SR
Battery Capacity, MWh_{ac}	0.003	2.50	0.006	2.50	5
PCS Initial Cost, $/kW	153	144	153	144	153
BOP Initial Cost, $/kW	100	100	100	100	100
Battery Initial Cost $/kW	368	356	368	356	640
Battery Initial Cost $/kWh	1,330,000	1,424	660,000	1,424	1,197
Total Capital Cost, M$	6.2	6.0	6.2	6.0	8.9
O&M Cost – Fixed, $/kW-year	14.8	15.1	14.8	15.1	26.5
O&M Cost– Variable, $/kW-year	6.7	6.7	6.7	6.6	1.0
NPV Disposal Cost, $/kW	0.5	0.6	0.5	0.6	1.2

Note: The total initial cost may calculated in two ways:
1. By mutiplying the sum of PCS, BOP and Battery initial costs expressed in $/kW by the reference power,
2. OR by mutiplying the sum of PCS and BOP expressed in $/kW by the reference power and then adding the product of Battery Initial cost expressed in $/kWh and the Battery Capacity

Fixed O&M costs are based on $2/kW for the PCS as prescribed in Chapter 5, plus battery maintenance in accordance with the vendor. The recommended maintenance program for Saft batteries consists of continuous remote monitoring and detailed inspections conducted at regular intervals, which include:

- Visual inspection for damage, leakage, or other physical problems with cells, interconnections, and connecting cables
- Cleaning the tops and sides of cells to remove dirt and deposited electrolyte salts
- Measurement of voltage, resistance, and specific gravity of electrolyte for each cell
- Replacing water lost during charging
- Measurement of resistance between terminals of adjacent cells
- Retorquing terminal connections as necessary
- Confirming the accuracy of DC voltage, DC current, and temperature sensors as necessary

The duration between such inspections depends on the use of the system. Systems which are not cycled often may require maintenance once in two years. Commonly cycled systems may require maintenance twice a year or more.

The O&M figures provided here are estimates based on those made for the GVEA BESS, and for the Saft Power Quality Battery. Fixed O&M costs are based on labor costs of $50 per hour (or $900 per module per year). In addition, an allowance for annual property taxes and insurance, based on 2% of the initial total capital costs, is included in the fixed O&M costs.

Variable O&M costs for the system include the cost of electrical losses to maintain the PCS and the battery during hot standby intervals.

An allowance for nickel-cadmium battery disposal costs is also included at the end of battery life, covering the cost of removing the battery from the plant. Batteries are usually accepted by manufacturers so that the active materials can be recovered and reused.

Lifecycle Benefit and Cost Analysis for Nickel-Cadmium Systems

Further insight to the value of energy storage can be gained through lifecycle cost analyses using a net present value (NPV) methodology and comparison with alternatives. The financial parameters in Table 7-3 are used to assess the applications described in the preceding sections and the assumed electricity rate structure is presented in Table 7-4.

Table 7-3
Financial Parameters

Dollar Value	2003
System Startup	June 2006
Project Life, years	20
Discount Rate (before tax), %	7.5
Property Taxes & Insurance, %/year	2
Fixed Charge Rate, %/year	9.81

Table 7-4
Electric Rates

Load Shifting On Peak Period	3	10
Number Cycles per year	60	250
On-Peak Energy, $/MWh	120	80
Off-Peak Energy, $/MWh	20	
Yearly Average Energy Charge, $/MWh	38	
Regulation Control, $MW-Hour (power), $/MWh	16	
Spinning Reserve, $MW-Hour (power), $/MWh	3	
Transmission Demand Charge, $/kW-mo	5	

The results of lifecycle cost benefit analyses of select nickel-cadmium applications are summarized in Table 7-5 and discussed below. The bases and methodology used in valuing energy storage applications is described in detail in Chapter 4. The details of the cost benefit analysis for each application are discussed below.

Table 7-5
Summary of Benefit and Cost Analyses of Nickel-Cadmium Systems

	Single Function			Combined Function	
Applications	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	App C: GFS -- 15 min FPD per cycle, 10 events/yr, 1 event/d	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr	App C1: GFS +GAS + GVS + RC	App C3: SPQ + LS3 + RC + SR
Alt Solution Value, $/kW	750	750	1,000	750	1,500
Initial Installed Cost, M$	6.21	6.00	6.21	6.00	8.93
Total Costs, M$	(9.0)	(8.8)	(9.0)	(8.8)	(14.8)
Total Benefits, M$	7.50	7.5	10.0	7.6	17.4
Benefit to Cost Ratio	0.84	0.857	1.11	0.863	1.18
NPV, M$	(1.5)	(1.3)	1.0	(1.2)	2.7
Battery Type	Saft Power Quality Battery 235 kW	Saft Pocket Plate SBH 920, 220-Module String	Saft Power Quality Battery 235 kW	Saft Pocket Plate SBH 920, 220-Module String	Saft Sintered Plate SPH 320, 74-Module String
Number of Strings	45	2	45	2	9
Battery 2006 Price, K$/string	81	1,712	81	1,712	688
Battery Price for NPV=0, K$/string	57	1,250	98	1,270	865

- Application A: Grid Angular Stability (GAS) – This application was evaluated on the assumption that an alternative system capable of mitigating GAS events can be obtained for capitalized acquisition and operating costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown inTable 7-5, this application yields a negative NPV of $(1.5) million for an initial investment of $6.2 million. As a measure of the sensitivity of NPV with respect to alternative system costs, Figure 7-6 illustrates the change in NPV over a range of $500 to $1000/kW, and shows that nickel-cadmium systems will compete against alternative solutions with net capitalized costs in excess of about $895/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the nickel-cadmium system were reduced from $81 to $57 thousand per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $750/kW.

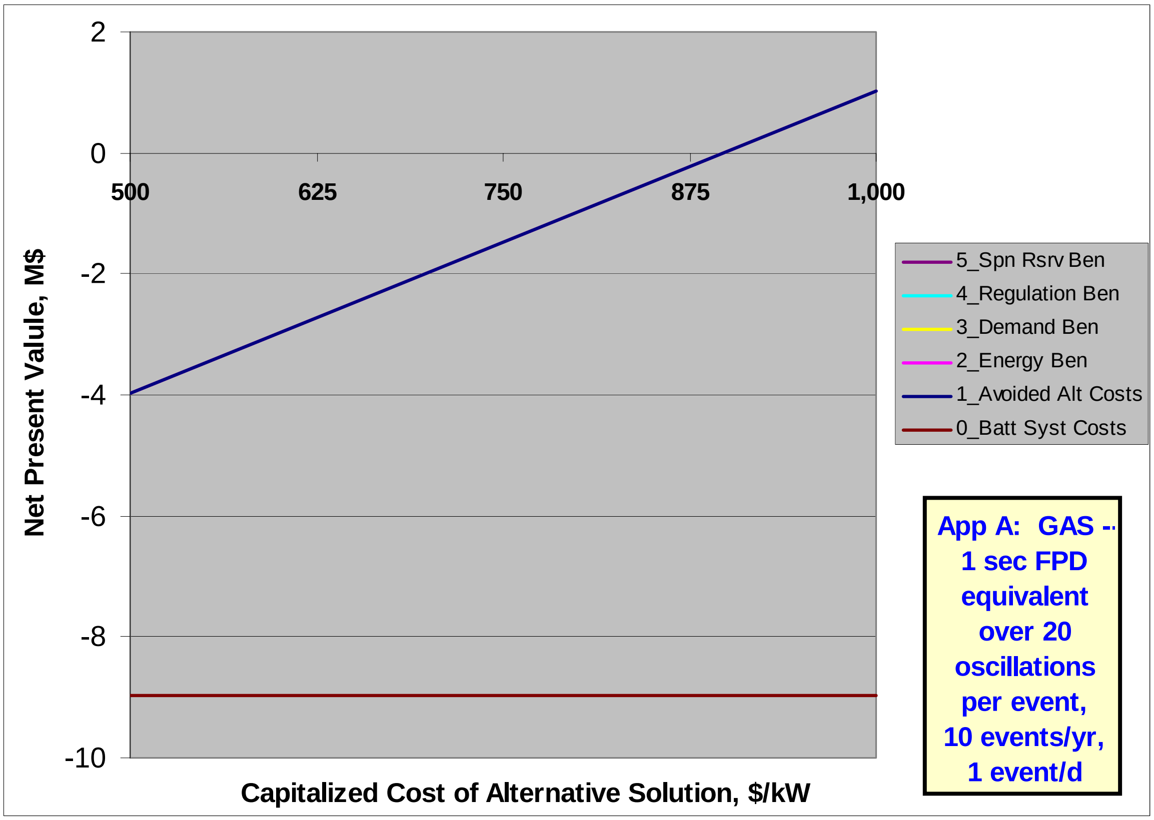

Figure 7-6
Application A: Nickel-Cadmium System NPV vs Cost of Alternative System

- Application C: Grid Frequency Stability (GFS) – This application was evaluated on the assumption that an alternative system capable of mitigating GFS events can be obtained for capitalized acquisition and operating costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 7-5, this application yields a negative NPV of $(1.3) million for an initial investment of about $6.0 million on this basis. As a measure of the sensitivity of NPV with respect to alternative system costs, Figure 7-7 illustrates the change in NPV over a range of $500 to $1000/kW and shows that this nickel-cadmium system will compete favorably against alternative solutions with net capitalized costs in excess of about $875/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the nickel-cadmium string were reduced from $1,712 thousand to $1,250 thousand per string, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $750/kW.

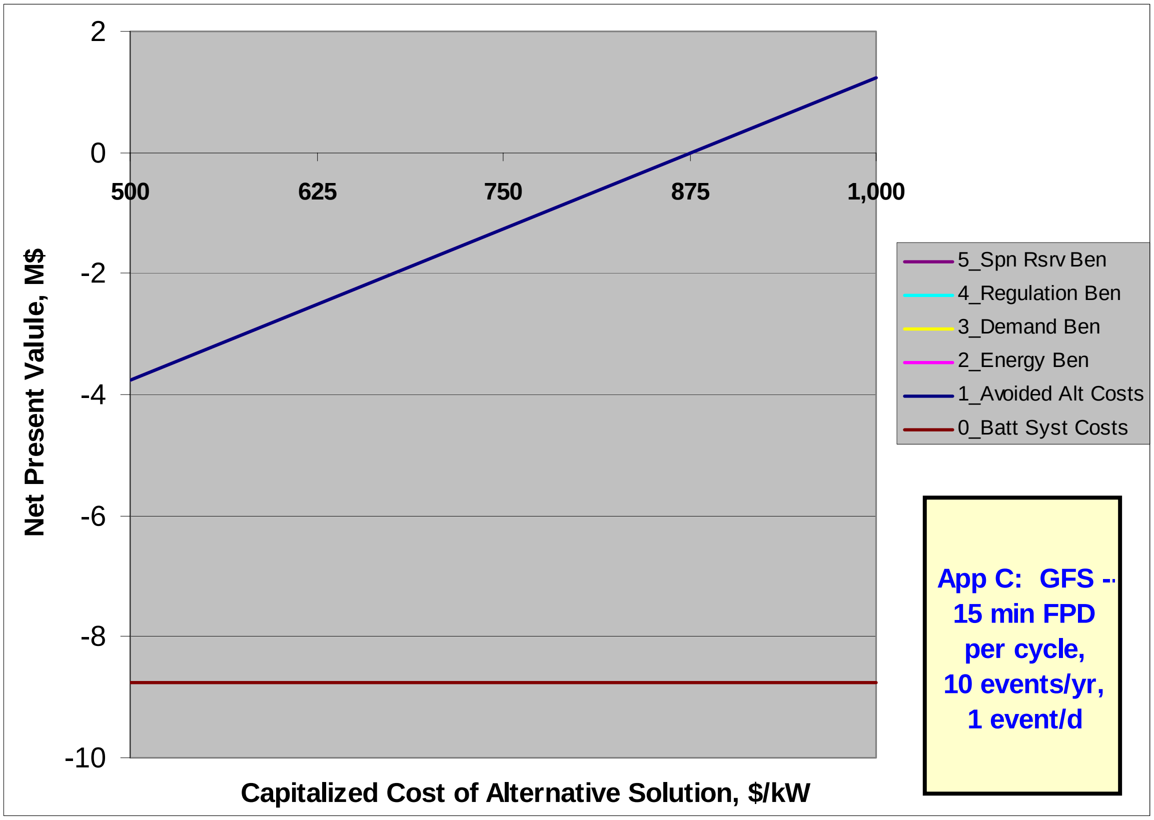

Figure 7-7
Application C: Nickel-Cadmium System NPV vs Cost of Alternative System

- Application F: Short Duration Power Quality (SPQ) – This application was evaluated on the assumption that an alternative system capable of mitigating SPQ events can be obtained for capitalized acquisition and operating costs of about $1000/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 7-5, this application yields a NPV of $1.0 million for an initial investment of about $6.2 million on this basis. As a measure of the sensitivity of NPV with respect to alternative system costs, Figure 7-8 illustrates the change in NPV over a range of $500 to $1500/kW and shows that nickel-cadmium systems will compete favorably against alternative solutions with net capitalized costs in excess of about $895/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the nickel-cadmium battery were increased from $81 to $98 thousand per system, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $1000/kW.

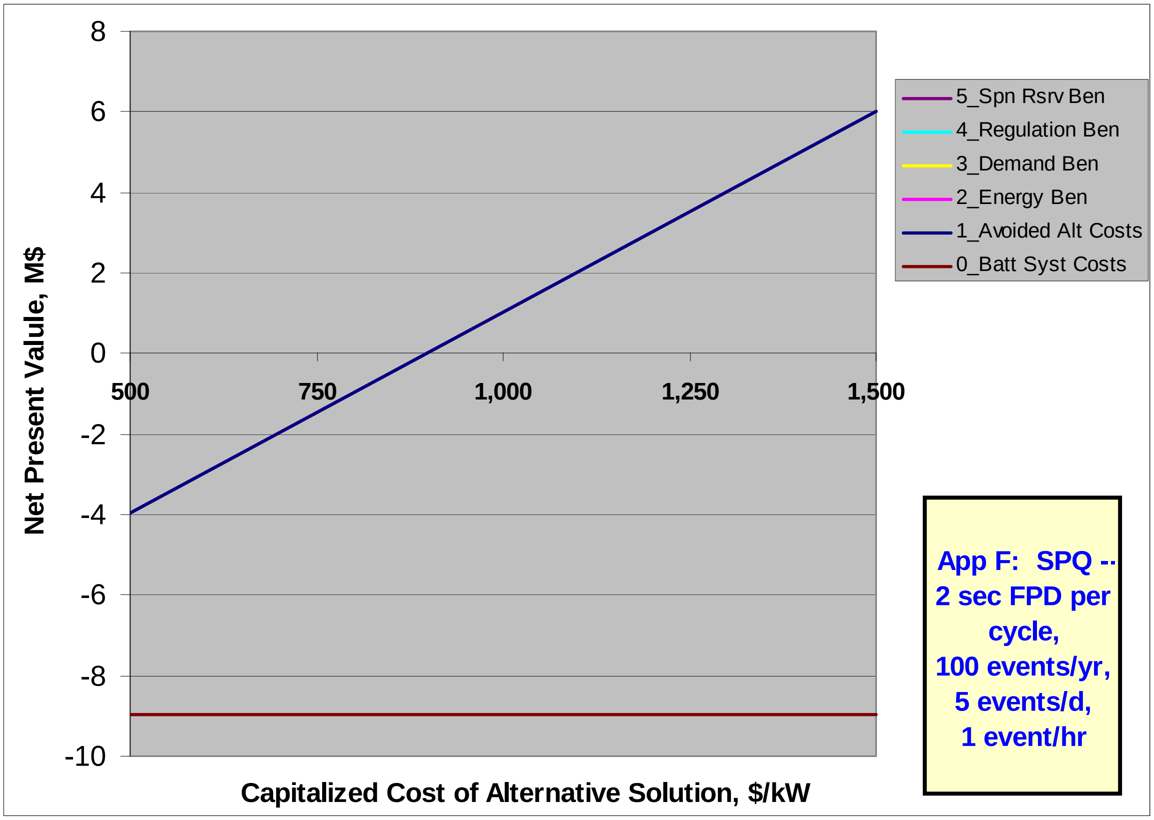

Figure 7-8
Application F: Nickel-Cadmium System NPV vs Cost of Alternative System

- Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC) – This application was evaluated on the assumption that an alternative system capable of mitigating GFS, GAS and GVS events can be obtained for capitalized acquisition and operating costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rate for regulation control is also included in the valuation. As shown in Table 7-5, this application yields a negative NPV of $(1.2) million for an initial investment of about $6.0 million on this basis. As a measure of the sensitivity of NPV with respect to alternative system costs, Figure 7-9 illustrates the change in NPV over a range of $500 to $1000/kW and shows that nickel-cadmium systems will compete favorably against alternative solutions with net capitalized costs in excess of about $865/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the nickel-cadmium string were reduced from $1,712 thousand to $1,270 thousand per string, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $750/kW. Note that the additional benefit gained from this combined application over the GFS application alone is very small. This is because the system can provide relatively little in the way of RC services.

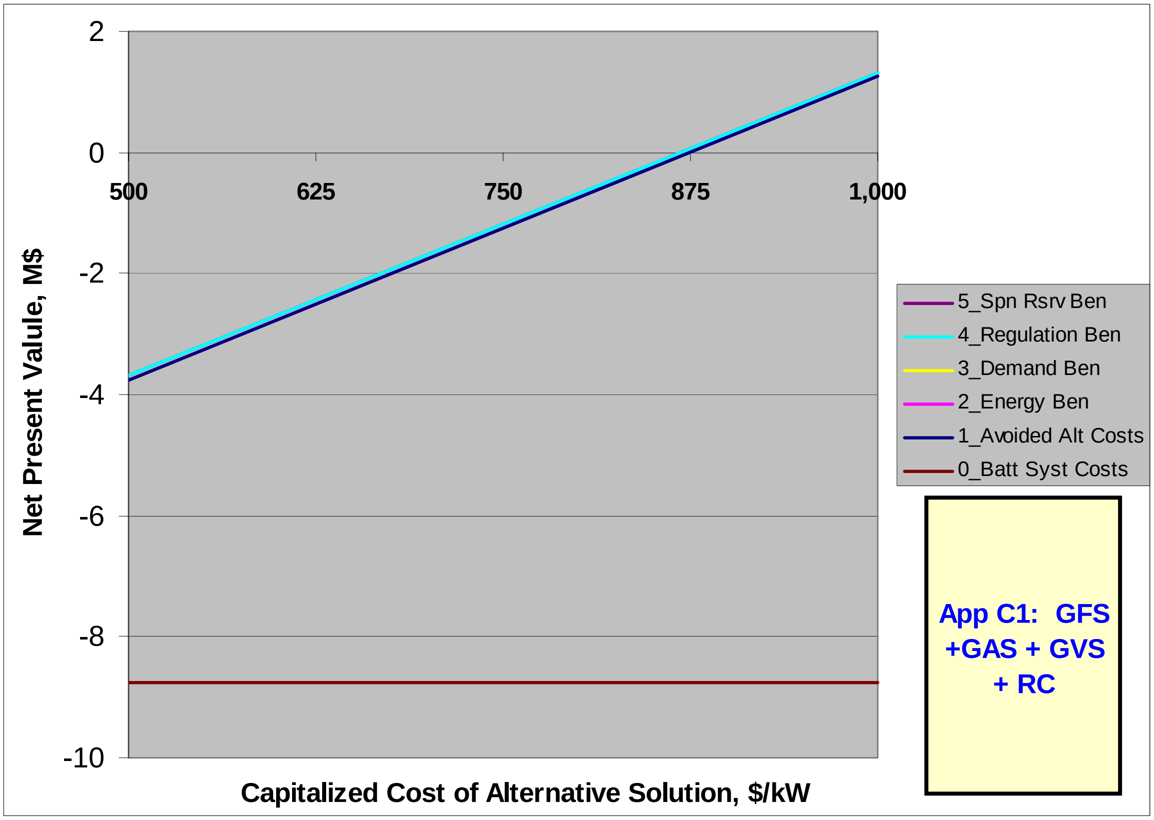

Figure 7-9
Application C1: Nickel-Cadmium System NPV vs Cost of Alternative System

- Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating SPQ events, plus avoided LS3 related upgrade costs, can be obtained for net capitalized costs of about $1500/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 3-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Table 7-5, this application yields a NPV of $2.7 million for an initial investment of about $8.93 million on this basis. As a measure of the sensitivity of NPV with respect to alternative system costs, Figure 7-10 illustrates the change in NPV over a range of $1000 to $2000/kW and shows that nickel-cadmium systems will compete favorably against alternative solutions with net capitalized costs in excess of about $1225/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the nickel-cadmium string were increased from $688 to $865 thousand per string, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $1500/kW. Note that the design for this application is significantly different from that for the SPQ application alone. This is necessitated by the repeated deep-cycle requirements for LS3, RC, and SR.

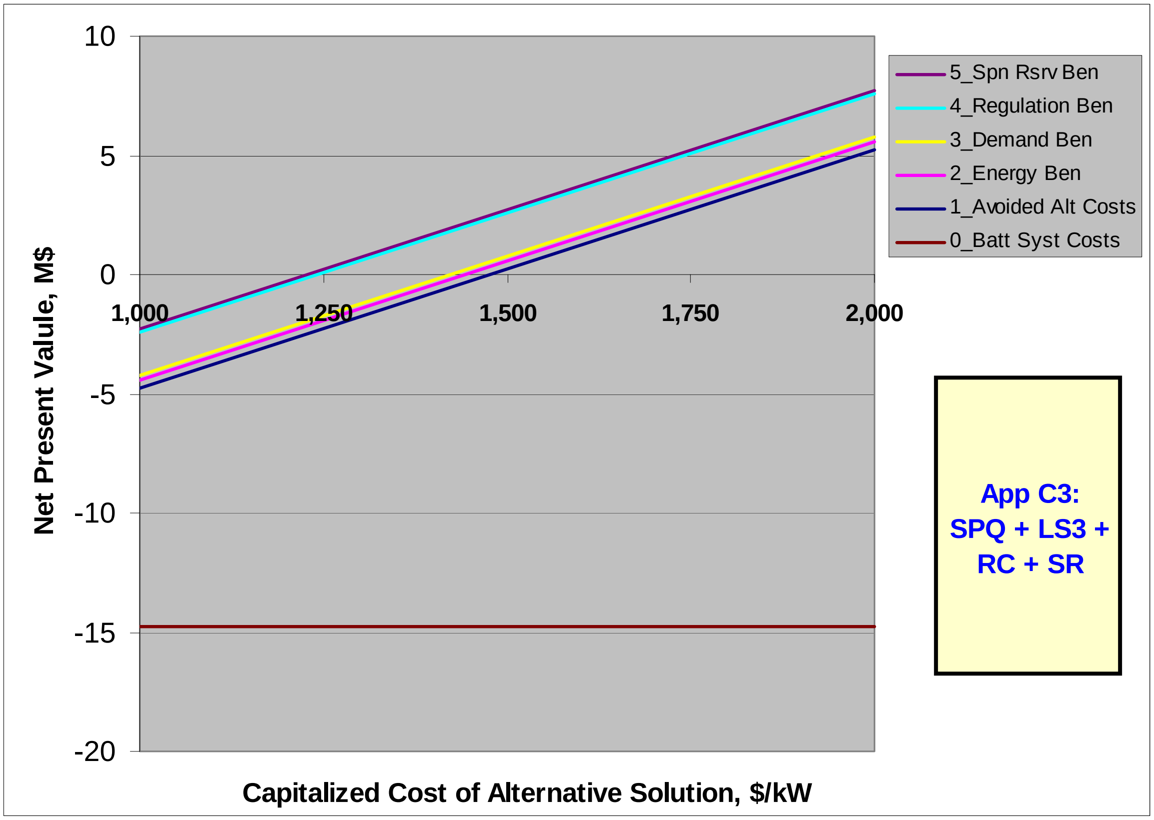

Figure 7-10
Application C3: Nickel-Cadmium System NPV vs Cost of Alternative System

Interpreting Results From Benefit-Cost Analyses

In general, nickel-cadmium battery systems are expected to be competitive in some single function applications as well as two of the combined function applications. Nickel-cadmium is best suited for applications where a relatively high discharge rate and a relatively large number of deep cycles are required. It should be noted that, in these examples, combination applications brought little additional value to the system in comparison to applications designed specifically for a single application. This seems to indicate that designing nickel-cadmium systems for simultaneous multiple applications requires costly changes which are only marginally justified by the additional benefit gained.

The reader is reminded that the foregoing analyses are intended as a guide to the initial consideration of energy storage options, and that these analyses are based on representative electric rates and costs for alternative systems as described in Chapter 4. The assumptions used herein should be reviewed in light of project specific applications, alternative solutions, electric rates and financial parameters.

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8
SODIUM-SULFUR BATTERIES

Introduction

Ford Motor Company is credited with initial recognition of the potential of the sodium-sulfur battery based on a beta-alumina solid electrolyte in the 1960's [1, 2]. By the early 1970's, Ford's work (Kummer and Weber) had catalyzed widespread research into sodium-sulfur battery technology, including programs in Europe (Brown Boveri (later ABB)) and in Japan (New Energy and Industrial Technology Development Organization (NEDO)), primarily for electric vehicle applications. By the late 1970's and early 1980's, a variety of developers had advanced sodium-sulfur technology for applications ranging from satellite communications to large stationary power. Notable contributors included Eagle Picher Industries in the U.S., Chloride Silent Power in the U.K., Asea in Sweden, Powerplex in Canada, and RWE in Germany. As recently as 1993, Ford equipped six electric Ecostar vehicles for use by the US Postal Service with sodium-sulfur batteries as part of a test program.

By the early 1980's, the Tokyo Electric Power Company (TEPCO) had selected sodium-sulfur technology as the preferred medium for dispersed utility energy storage to displace a growing reliance on central pumped hydro energy storage. TEPCO recognized that the key to development of sodium sulfur batteries suitable for utility-scale stationary power applications was in the production of ceramic components and sought the participation of NGK Insulators, Ltd., (NGK) for that role. By the late 1990's, NGK and TEPCO had deployed a series of large scale demonstration systems, including two, 6 MW_{ac}, 48 MWh_{ac} installations at TEPCO substations. At present, NGK is the only known vendor of sodium sulfur batteries for utility applications, and the technology presented herein pertains to NGK's sodium-sulfur (NAS®, registered in Japan) battery module product lines.

In April 2002, TEPCO and NGK announced commercialization of their sodium-sulfur battery product lines in Japan, plus their intent to introduce products globally. In September 2002, the first NAS battery demonstration project was deployed in the U.S. The project was hosted by the American Electric Power Company (AEP), and project partners include TEPCO, NGK, ABB, EPRI and DOE through the Sandia National Laboratories. In April 2003, NGK expanded their manufacturing capacity to 65 MW_{ac} or 1300 modules per year with plans for expansion to 150 to 200 MW_{ac} in a few years.

Description

Electrochemistry

The normal operating temperature of sodium-sulfur cells is about 300C. During discharge, the sodium (negative electrode) is oxidized at the sodium/beta alumina interface, forming Na^+ ions. These ions migrate through the beta alumina solid electrolyte and combine with sulfur that is being reduced at the positive electrode to form sodium pentasulfide (Na_2S_5). The sodium pentasulfide is immiscible with the remaining sulfur, thus forming a two-phase liquid mixture. After all of the free sulfur phase 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. Half-cell and overall-cell reactions are as follow:

Negative electrode: $$2NA \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} 2NA^+ + 2e^-$$ **Eq. 8-1**

Positive electrode: $$xS + 2e^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} S_x^{-2}$$ **Eq. 8-2**

Overall cell: $$2NA + xS \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} Na_2S_x$$ **(x = 5 to 3), E_{ocv} = 2.076 to 1.78 V** **Eq. 8-3**

Although the actual electrical characteristics of sodium-sulfur cells are design dependent, voltage behavior follows that predicted by thermodynamics. A typical cell response is shown in Figure 8-1. This figure is a plot of equilibrium potential (or open circuit voltage (OCV)) during charge and discharge as a function of depth of discharge. The OCV is a constant 2.076V over 60 to 75% of discharge while a two-phase mixture of sulfur and Na_2S_5 is present. The voltage then linearly decreases while discharged within the single-phase Na_2S_x regime to the selected end-of-discharge, usually about 1.8 V. Greater depths of discharge cause the formation of Na_2S_x species with progressively higher internal resistance and greater corrosivity [3, 4].

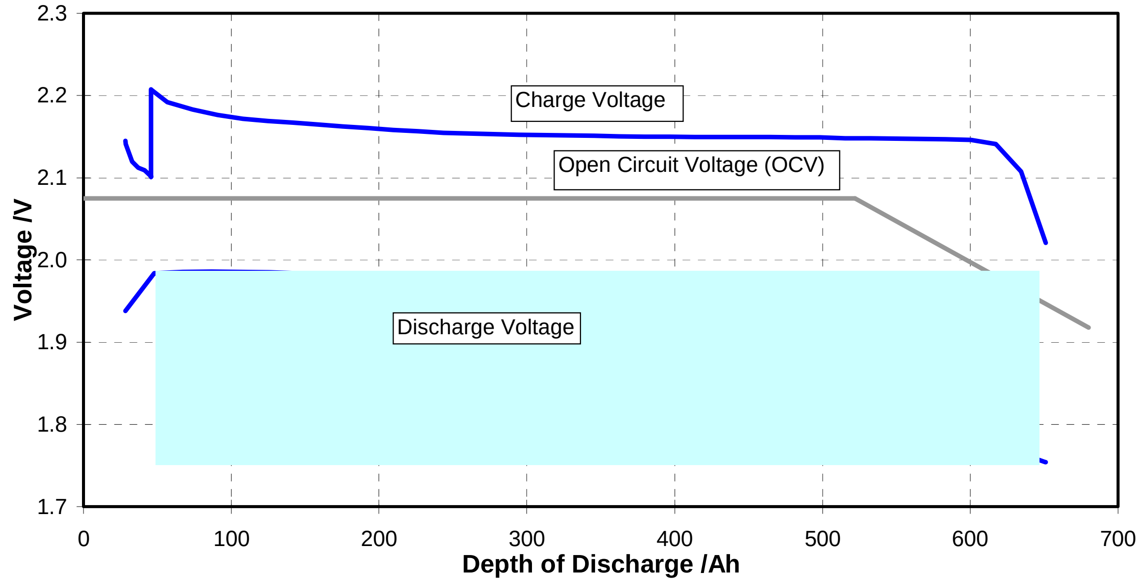

Figure 8-1
NAS Cell Voltage Characteristics (Courtesy NGK)

NAS Cell Design

The NAS cell design developed by NGK is illustrated in Figure 8-2. The negative sodium electrode in the center is surrounded by the beta alumina solid electrolyte tube, which in turn is surrounded by the positive sulfur electrode. In a charged state, liquid elemental sodium fills the central reservoir. As the cell is discharged, the liquid sodium is channeled through a narrow annulus between the inner surface of the beta alumina solid electrolyte and the safety tube. The safety tube is a design feature to control the amount of sodium and sulfur that can potentially combine in the unlikely event that the beta alumina tube fails. The volume of potential reactants is limited to that contained in the narrow annulus between the electrolyte tube and the safety tube, preventing the generation of sufficient heat to rupture the cell.

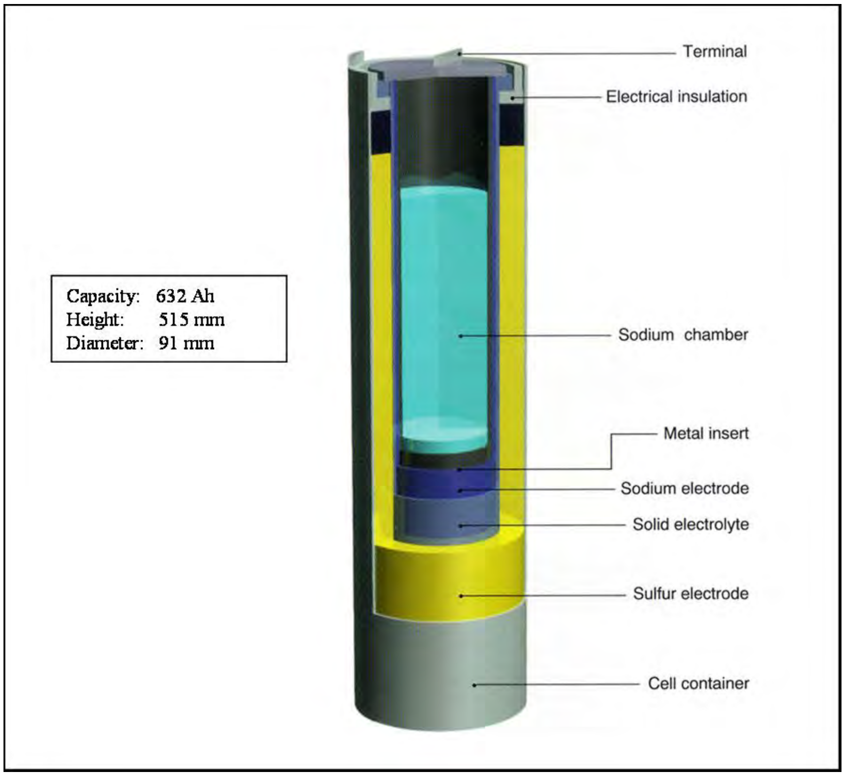

Figure 8-2
NAS Battery Cell (Courtesy NGK)

NAS Battery Module Design

NGK has developed the NAS T5 cell for use in their commercial battery modules which are designated the NAS PS (for peak shaving) Module and the NAS PQ (for power quality) Module. The properties of the NAS T5 cell and the PS and PQ Modules are provided in Table 8-1.

While both the PS and PQ Modules use the same T5 cell, the PS Module is designed for long duration discharge with modest voltage drop, and the PQ Module for pulse power delivery with discharge voltage as low as 0.9 V_{pc}. The most notable design differences are in cell arrangements and electrical protection. PS Modules use 320 or 384 cells in arrays of 8 cells in series to yield module DC voltages of 64 or 128, while all 320 cells within a PQ Module are series connected for 640V_{dc}. The PS Module arrangement allows fuses to be incorporated within each 8-cell string. Electrical protection for the deeper voltage drops and higher currents encountered in PQ Module applications are addressed via an external DC breaker and a fuse at the terminals of each module.

A NAS Battery Module consists of the cell arrangements described above within a thermally insulated enclosure equipped with electric heaters to maintain a minimum operating temperature of about 290C, depending on the application. Cells are closely spaced and connected in series and parallel for the PS modules and series for the PQ module. A vacuum is drawn on the gap between the inner and outer walls of the enclosure to manage heat loss. This design feature enables the heat transfer characteristics of the PQ Modules to be adjusted to the needs of the application. As indicated in Table 8-1, units used in standby applications reject heat at about 2.2 kW_{ac} under design basis conditions, while units for combined PQ and PS functions lose about 3.4 kW during standby. Figure 8-3 is a photograph of a NAS PS Module with the top cover removed to show cells. The interstices between cells are filled with sand which functions as both packing material and heat sink.

Table 8-1
NAS Cell and Module Properties

Parameter	NAS T5 Cell	NAS Battery Modules		
		E50 PS Module	**G50 Module**	**PQ50 Module**
Nominal Voltage, V_{dc}	2	64 or 128		640
Operating Temperature	[290 to 360C]			
Cell Arrangement ("s" series; "p" parallel)	Single	(8s x 6p) x 8s or (8s x 12p) x 4s	(8s x 5p) x 8s or (8s x 10p) x 4s	320s
Electrical Protection	NA	Internal fuse within each 8s string		DC breaker and external fuse
Rated PS Capacity (Notes 1, 2)	628 Ah	430 kWh_{ac}	360 kWh_{ac}	
Rated PS Power (Notes 1, 3)	NA	50 kW_{ac}		
Max Power for Interval Noted (Note 1, 4)	NA	100 kW_{ac} for ~2hr		250 kW_{ac} for 30sec
Pulse Factor (Note 5)	NA	2		5
Projected Calendar & Cycle Life	15 years: 4500 to 90%, 2500 to 100% DOD cycles			
Avg DC Efficiency, %	90	85		
Standby Heat Loss, kW	NA	3.4		2.2 (PQ) 3.4 (PQ+PS)
Dimensions, mm (in)	515L x 91Φ (20.3L x 3.6Φ)	2,270W x 1,740D x 720H (89.4W x 68.5D x 28.4H)		
Weight, kg (lb)	5.5 (12.1)	3500 (7920)		

Notes:
1. AC rating based on 95% inverter efficiency
2. Design basis Rated PS Capacity based on 1.82Vpc OCV at end of discharge and end-of-life
3. Design basis Rated PS Power for reference peak shaving profile yielding 100% DOD
4. Maximum power for short duration discharges (typically yield less than 100% DOD)
5. Pulse Factor: Ratio of maximum power to rated power for stated duration.

(Values above are the maximum achievable with operating temperature and electrical protection designs for the battery module.)

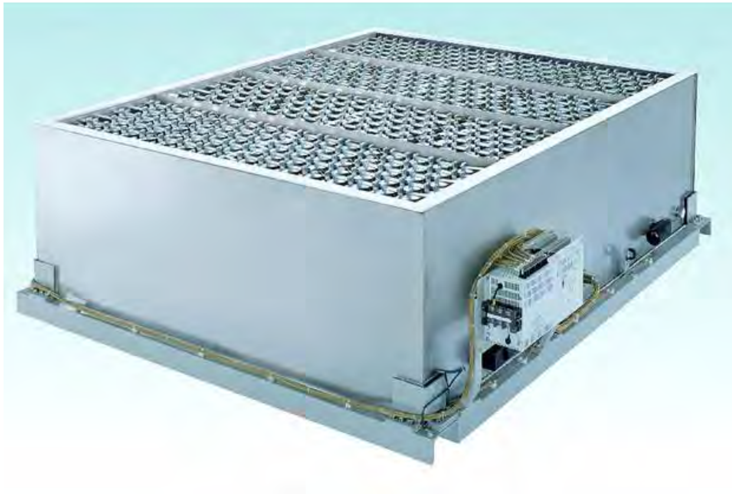

Figure 8-3
NAS PS Module (Courtesy NGK)

Voltage and temperature profiles during a 100% charge-discharge cycle of a NAS PS Module are shown in Figure 8-4. (Temperature sensors are located on the inner side and bottom surfaces of the enclosure and are insulated from cells by the sand filler; hence, temperature data lag duty cycle events due to the rate of heat transfer from cells to the sensor location.) The internal temperature of the module is observed to increase steeply during discharge mode due to the combined effects of ohmic heating (I^2R) and the exothermic cell reaction. During the charge mode, ohmic heating combines with the cell endothermic reaction to effect a gradual cooling. Resistance heaters on the inner side and bottom of the enclosure maintain the module at a temperature above 290C during standby.

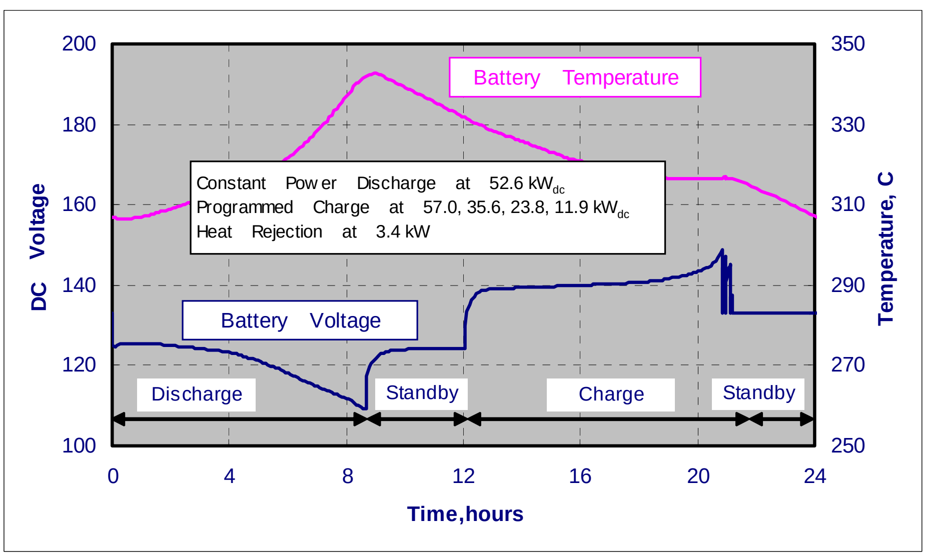

Figure 8-4
PS Module Voltage & Temperature During a Peak Shaving Cycle (Courtesy NGK)

Reference peak shaving profiles for all three modules are shown in Figure 8-5. These profiles show a gradual increase in power at the beginning of the discharge interval to minimize grid transients, a constant power plateau, and a gradual decrease in power at the end. These profiles illustrate a thermal management strategy that allows 100% depth of discharge within temperature limits over the minimum time interval. Since the majority of applications that only involve peak shaving do not require a rapid transition of power, these profiles are deemed to be an acceptable basis for defining basic performance parameters for NAS products. As shown on the figure, the Rated PS Capacity is 360 kWh_{ac} for the PQ50 and G50 Modules, and 430 kWh_{ac} for the E50 Module. The Rated PS Power for both modules is 50 kW_{ac}.

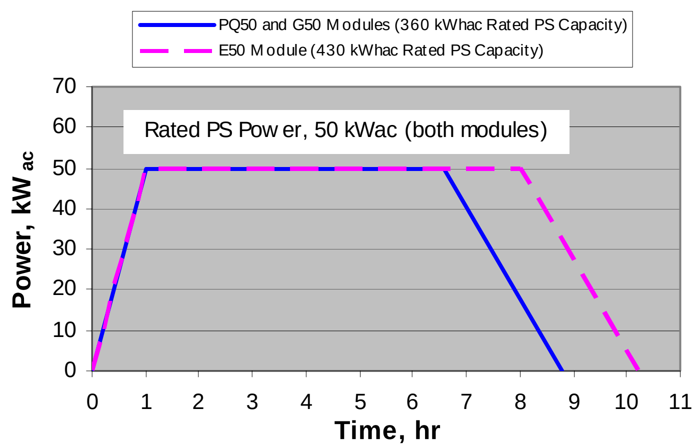

Figure 8-5
Reference Peak Shaving Profiles (Both Modules)

While gradual load changes yield the most energy efficient duty cycle, mitigation of power disturbances such as sags and momentary outages requires step load changes within a few milliseconds. All NAS modules can reach full power within one millisecond, and the PQ50 Module has been specifically developed for PQ and combined PQ and PS applications. Figure 8-6 illustrates the capability of the PQ Module to deliver step load pulses of power for durations ranging from 30 seconds to 3 hours. (Thermal management of longer duration discharges requires discharge profiles similar to those shown in Figure 8-5.) As noted in Table 8-1, NGK defines the term "Pulse Factor" as the ratio of the maximum power for the stated duration to the Rated PS Power. For example, the PQ Module can deliver 400% Rated PS Power (i.e., 4 times 50 kW equals 200 kW) for 15 minutes as indicated Figure 8-6.

The E50 and G50 Modules can deliver step load pulses corresponding to the profile shown in Figure 8-6 up to a Pulse Factor of about 2.0 with an associated reduction in deliverable stored energy. Alternatively, these modules can deliver 60 kW_{ac} (120% of rated power) for up to 3 hours, plus the balance of stored energy at a rate of 25 kW_{ac}.

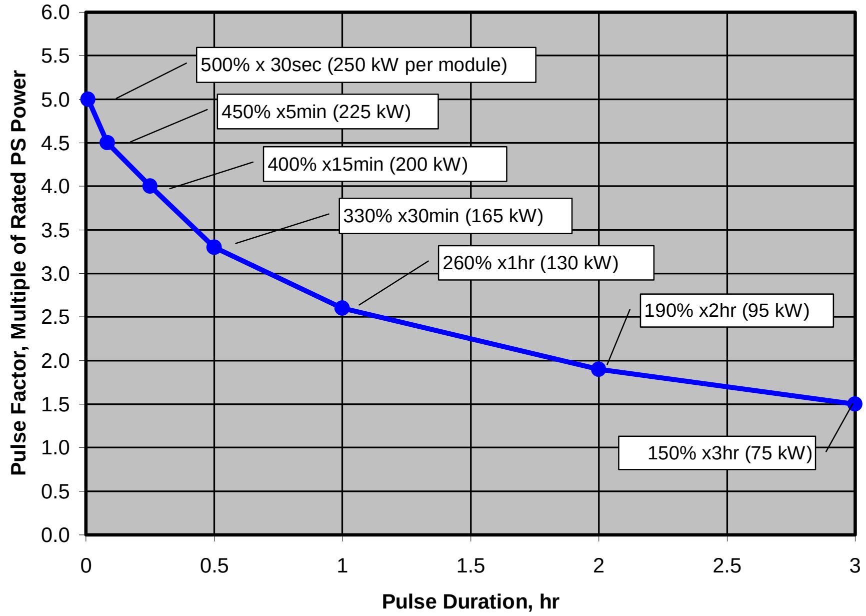

Figure 8-6
PQ50 Module Pulse Power Capability

The PQ Module was introduced in recognition that it is often necessary to combine energy storage functions to offer a cost competitive system. For example, in some circumstances, the mitigation of short duration power disturbances can be combined with peak shaving such that the same facility accomplishes both functions. Typically, the energy storage system is sized to protect the critical load using the Pulse Factor multiplier, and peak shaving is conducted at the Rated PS Power. Table 8-2 provides a list of operating regimes for the PQ Module including those that combine pulse power and peak shaving functions. The operating regimes are defined by NGK such that pulse power capability is maintained over the module life and battery temperatures remain within thermal limits during all modes of operation.

Table 8-2
NAS PQ Module Combined Pulse and PS Operating Regimes

Operating Regime	Pulse Factor (1)	Pulse Interval (2)	PS Energy, kWhac (3)	Recharge Interval, hr (4)	# PS Cycles Over Life (5)	Coincident Pulse & PS (6)
30 second pulse duration						
1	5.0	1hr	0	NA	0	NA
2	4.3	2x/hr	155	5	2500	Yes
3	3.0	1hr	360	10	2500	Yes
4	3.0	5x/hr	155	5	5000	Yes
5 minute pulse duration (plus 30 sec cumulative within any prior 1 hour)						
5	4.5	12hr	0	NA	0	NA
6	3.5	12hr	155	5	500	Yes
7	3.5	12hr	360	10	500	No
15 minute pulse duration (plus 30 sec cumulative within any prior 1 hour)						
8	4.0	12hr	0	NA	0	NA
9	3.7	12hr	155	5	500	No
1 hour pulse duration (plus 30 sec cumulative within any prior 1 hour)						
10	2.6	12hr	0	5	0	NA

Notes
(1) Pulse Factor: Multiple of Rated PS Power for short duration power delivery
(2) Pulse Interval: Interval between successive pulses of the magnitude noted. For 5 minute, 15 minute, and 1 hour PQ regimes; cumulative short pulses up to 30 seconds per hour prior to a 5 minute, 15minute , or 1 hour pulse are also acceptable.
(3) PS Energy: Energy delivered from NAS battery during PS cycle (see profile)
(4) Recharge Interval: Minimum interval to recharge unit for next cycle
(5) # PS Cycles Over Life: The design basis number of 42% (155kWh) or 100% (360kWh) DOD cycles over the life of the system
(6) Coincident PQ & PS: Acceptability of simultaneous pulse and PS events with respect to thermal management

With either PS or PQ module applications, the cycle life can be an important design parameter. Based on both accelerated testing results and modeling projections, NGK has established a cycle life versus depth-of-discharge (DOD) relationship as shown in Figure 8-7. This relationship is used in calculating the expected battery life in combined function applications such as load shifting with grid regulation control using the conventional cumulative damage concept.

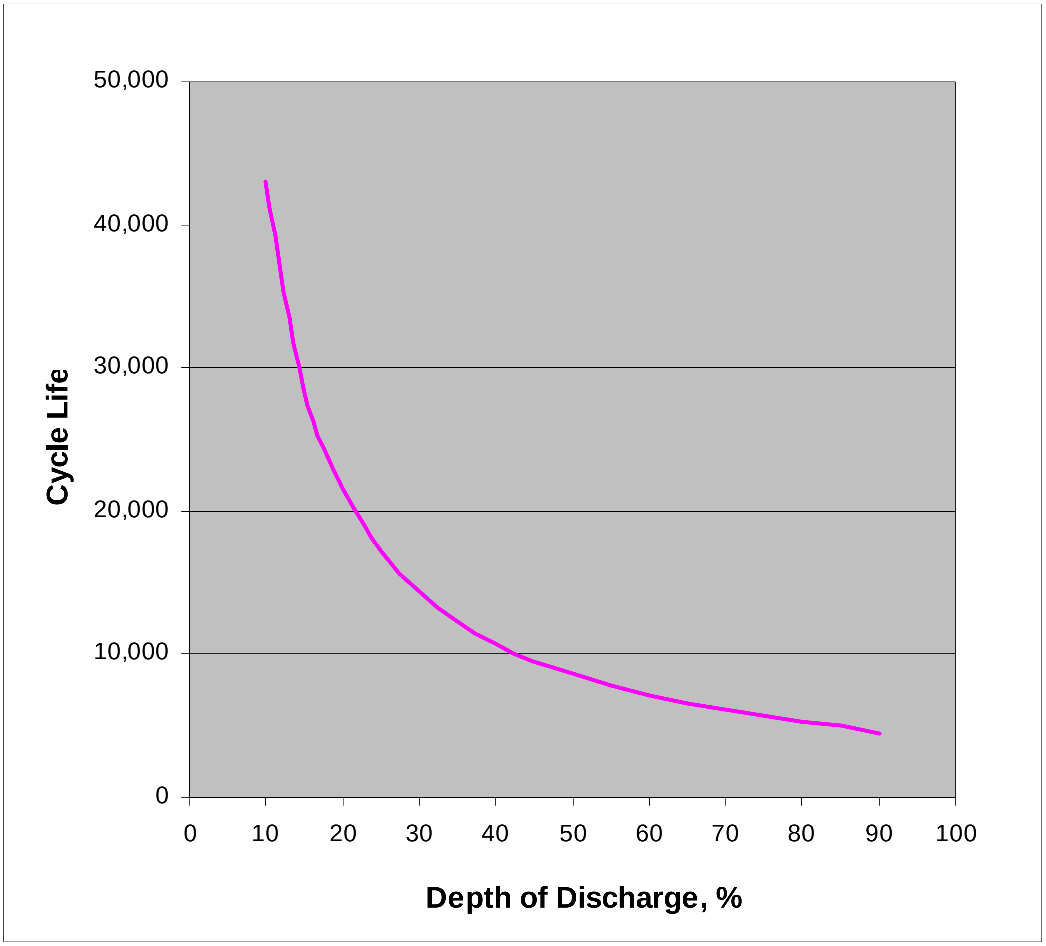

Figure 8-7
Projected NAS Battery Cycle Life (Courtesy NGK)

As described in [5], extensive safety testing of NAS battery modules has been conducted under simulated accident conditions for fire, flood, vibrations, and mishandling events, as well as for electrical malfunctions. Successful test results and operational experience gained from the demonstration projects have provided the bases for the NAS battery being approved by the Japanese Hazardous Material Safety Techniques Association for unrestricted siting and remote operation and monitoring. As with all reactive materials, there are procedures for shipping and handling, plus the local fire marshal is to be informed of the siting of reactive material quantities to assure appropriate fire extinguishing techniques and precautions are applied.

NAS Battery Installations

Figure 8-8 is a photograph of the 6 MW_{ac}, 48 MWh_{ac} NAS system at TEPCO's Ohito substation. A similar installation has been constructed at TEPCO's Tsunashima substation. These arrangements provide the bases for arrangement data used in economic evaluations.

Figure 8-8
6MW, 48MWh NAS System at TEPCO's Ohito Substation (Courtesy TEPCO)

Figure 8-9 shows a dimensioned layout for NGK's recently introduced NAS 20 Module Building Block product line. As illustrated, modules are arranged in exterior enclosures in four stacks of five modules each, corresponding to a nominal rated power of 1 MW_{ac}, 7.2 MWh.

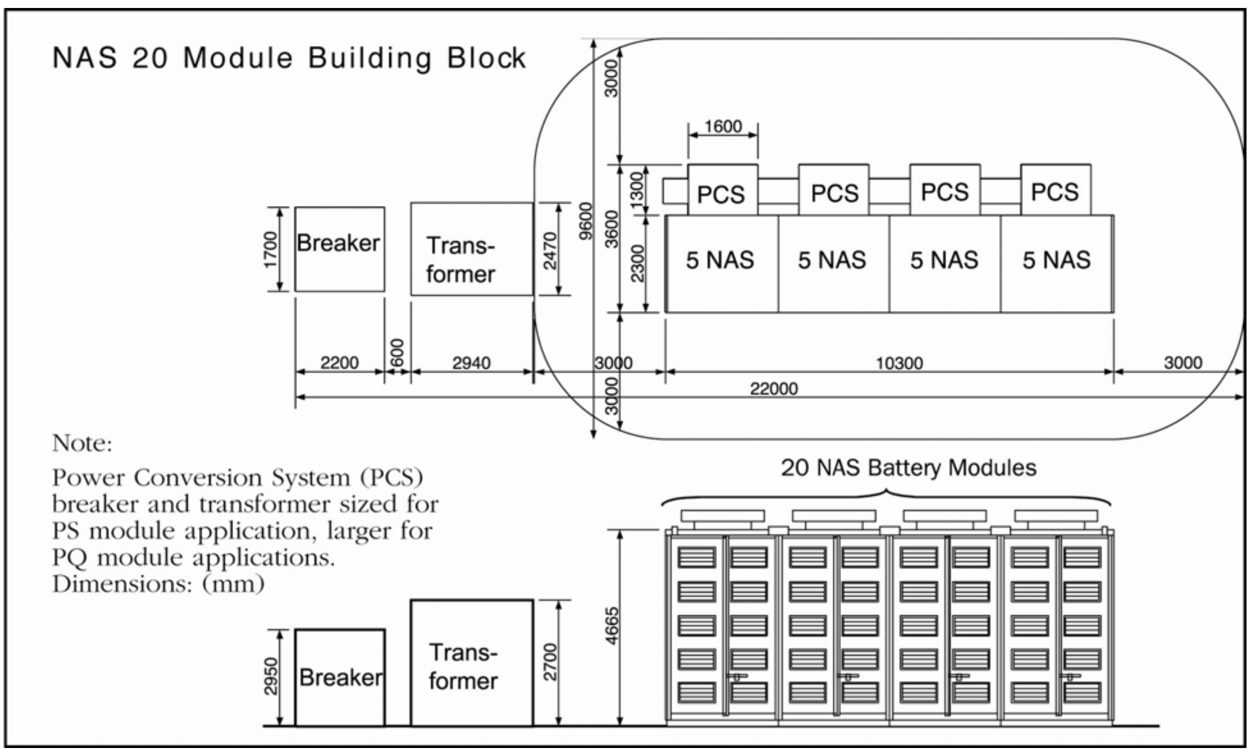

Figure 8-9
NGK's Standard 1 MW_{ac} Building Block (Dimensions, mm) (Courtesy NGK)

A goal of NAS battery development is to require minimal onsite maintenance. Current NAS system operation in Japan is unattended and fully automatic. NGK's recommended maintenance program consists of continuous remote monitoring and thorough inspections conducted at 3-year intervals. Details of the program are described in the later section titled, NAS Battery System Compliance with Application Requirements.

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.

Status of Sodium Sulfur Batteries

Development and Demonstrations

Table 8-3 lists 19 NAS battery demonstration and early commercial projects through March 2003 rated at 500kW_{ac} or more for cumulative capacity in excess of 32 MW_{ac} and 240 MWh_{ac}, including two, 6 MW_{ac}, 48 MWh_{ac} installations at TEPCO substations. Thirty projects smaller than 500 kW_{ac} have also been deployed and add another 3.5 MW_{ac} and 25 MWh_{ac} of NAS-based capacity.

The pre-commercial development and demonstration program sponsored by TEPCO was conducted in recognition of the empirical nature of ceramics technology. The cost, performance and reliability of NAS cells require that beta alumina solid electrolyte with high strength, low ionic resistivity and excellent stability is economically mass-produced. Proof that these requirements had been met required prototypic manufacturing facilities, full-scale demonstrations and the accumulation of sufficient data to warrant launching commercialization.

Table 8-3
In-Progress NAS Battery Systems Rated at 500 kWac or More

No.	Customer	Site	kW/kWh	Purpose	Start of Operation
1	TEPCO	Kawasaki Test Site	500/4000	Load Level	Jun-95
2	TEPCO Unit 1	Tsunashima Substation	6000/48000	Load Level	Mar-97
	Unit 2	(Unit 2 relocated, see "5")			Jul-97
	Unit 3				Jan-98
3	NGK	Head Office	500/4000	Load Level	Jun-98
4	TEPCO Unit 1	Ohito Substation	6000/48000	Load Level	Mar-99
	Unit 2	(Unit 2 relocated, see "18")			Jun-99
	Unit 3				Oct-99
5	TEPCO/TOKO	Saitama	2000/16000	Reloc "2", LL	Jun-99
6	Chubu EPCO	Odaka Substation	1000/8000	Load Level	Mar-00
7	TEPCO	Tsunashima Substation (New Unit 2)	2000/14400	Load Level	Nov-00
8	TEPCO	Shinagawa Substation	2000/14400	Load Level	Mar-01
9	TEPCO/Asahi Brewery	Kanagawa Plant	1000/7200	LL+UPS	Oct-01
10*	Metro City of Tokyo	Kasai Sewerage	1200/7200	LL+UPS	Oct-01
11	TEPCO/Takaoka	Oyama Plant	600/1440	LL+UPS	Oct-01
12	TEPCO/Takaoka	Oyama Plant	800/5760	Load Level	Feb-02
13	TEPCO/Fuji Xerox	Ebina Plant	1000/7200	Load Level	Feb-02
14	TEPCO/Pacifico	Media Center	2000/14400	LL+UPS	Apr-02
15	TEPCO	Chichibu Substation	1000/7200	Load Level	Jun-02
16*	TEPCO/Fujitsu	Akiruno Technology Ctr	3000/7200	LL+UPS (PQ=3)	Jun-02
17*	TEPCO/Tokyo Dome	Tokyo Dome Renovation	1000/7200	LL+EPS	Jul-02
18*	TEPCO/Ito Yokado	Maebashi Shopping Ctr	1000/7200	Reloc "4", LL	Jul-02
19	AEP	Gahanna, OH, USA	500/720	LL+UPS (PQ=5)	Sep-02
20	TEPCO	Ito Yokado Shopping Ctr	1000/7200	Reloc "17", LL	Oct-03
21*	TEPCO	Honda/Togichi Lab	1800/10800	Load Level	Dec-02
22*	TEPCO	Robinson Japan	1000/7200	LL+UPS	Dec-02
23*	TEPCO	Mitsui Norin/Sutama Factory	500/3600	LL+UPS	Jan-03
24*	TEPCO	City of Tokyo/Kasai Sewage	1000/7200	LL+EPS	Mar-03
25*	TEPCO	Muraya Water Station	1000/7200	LL&EPS	Mar-03
* Early commercial projects					

The first demonstration of NAS technology in the US is a multi-functional unit using two NAS PQ Modules for combined power quality and peak shaving. The demonstration is an EPRI Tailored Collaboration (TC) research project with American Electric Power (AEP). The NAS unit can deliver 500 kW_{ac} for up to 30 seconds for power quality protection plus 158 kWh_{ac} peak shaving at a maximum power of 100 kW_{ac} or it can provide 30 seconds power quality protection at 300 kW_{ac} plus deliver 720 kWh_{ac} peak shaving at a maximum power of 100kW_{ac}. Figure 8-10 is a photograph of the NAS unit installed at AEP's site.

This project evolved from an initial joint agreement between AEP, TEPCO and NGK. The power electronics and system integration was supplied by ABB. Extensive acceptance testing was conducted at ABB's factory in New Berlin, WI and the AEP site. The unit was formally commissioned in September 2002, at AEP's offices in Gahanna, Ohio (near Columbus). Performance monitoring for a period of two years and an evaluation of the economic potential of the project will be conducted under the EPRI/AEP TC project. An initial report on the design and acceptance testing is in [6]. Performance will also be monitored and assessed via a DOE sponsored program led by Sandia National Laboratories. After the first year of operational experience, the NAS battery has performed in accordance with specifications, and there have been no battery-related issues limiting operation. However, the PCS and control system have been the source of issues related to control logic and grid interactions typical first-of–a-kind equipment. The resolution of these issues has been addressed by AEP and ABB. AEP has given numerous status reports at industry meetings such as reported in [7].

Figure 8-10
AEP's 500 kWac (PQ) / 720 kWhac (PS) NAS Unit (Courtesy AEP)

Commercialization

As of April 2002, TEPCO and NGK formally commenced the sale of commercial NAS products in Japan, in concert with NGK's commitment to expand their manufacturing facilities. One year later, NGK started operation of expanded and new facilities with a nominal capacity of 65 MW_{ac} or 1300 modules per year. NGK plans to further expand 200MW_{ac} per year within a few years and targets 400 MW_{ac} per year in the longer term.

TEPCO distributes NAS systems within its service area to select commercial and industrial customers for combinations of peak shaving, emergency power and power quality while gaining benefits of increased asset utilization and customer commitment. A couple of other Japanese utilities have already followed the TEPCO business model and other Japanese utilities are also expected to do the same. NGK has also teamed with a major power electronics vendor to provide commercial systems in other Japanese markets. NGK also plans to expand manufacturing and team with one or more power electronics vendors to offer NAS systems in foreign markets commensurate with opportunities.

The status of the NAS battery product lines is characterized in Table 8-4. The NAS PS Module is best suited for energy management up to ~20 MW_{ac}, e.g., load leveling and broad peak demand reduction, plus mitigation of power disturbances and outages for up to several hours. The NAS PQ Module is best suited for pulse power applications up to ~100 MW_{ac} such as prompt spinning reserve, voltage and frequency support, short duration power quality protection and short peak demand reduction. Typical for many new power systems, a key challenge is the scale-up of mass production facilities to achieve the lower unit costs and prices for improved competitiveness needed for accessing the broader markets that are in turn needed to warrant the investments in the production facility scale-ups. Other challenges and issues relate to achieving the multiple functional values from combined applications within the restructured utility industry, which is also key to the economics for accessing broad markets. Along the way as sufficient experience is established, certification at the utility and the consumer level will need to be addressed.

Table 8-4
The Status of NAS Commercial Product Lines

Technology Variants/ Product Line	Peak Shaving (NAS PS Module)	Power Quality (NAS PQ Module)
Status	Commercial (in Japan)	Early Commercial (in Japan) Demonstration (in US)
Target Markets,	Utility and large Commercial/ Industrial >500kW_{ac} to ~20MW_{ac}	Utility and large Commercial/ Industrial >2MW_{ac} to ~100MW_{ac}
Funding Organizations	TEPCO, NGK	
Power Electronics Vendors	Teaming arrangements in progress	
Major Demonstrations (See Table 8-3)	See especially, TEPCO substations at Ohito and Tsunashima, 6MW_{ac}, 48MWh_{ac}	See Fujitsu, 3MW_{ac} (Pulse Factor: 3) and AEP, 500kW_{ac} (Pulse Factor: 5)
Lessons Learned	Confirmed commercial scale manufacturing of large cells and modules Confirmed utility scale operations	Value of prompt battery response PCS design and integration for combined PS and PQ
Major Development Trends	Mass production scale-up	
Challenges and Issues	Establish competitiveness, certification and system vendor(s) (outside Japan) Validate multiple functional value accrual	Establish competitiveness, certification and system vendor(s) (outside Japan) Stabilize PCS/integrated control system design(s). Validate multiple functional value accrual

T&D System Energy Storage Applications

Select Applications for NAS Battery Systems

This section presents the select applications for which the NAS is suited and describes the key features of the NAS systems when configured to meet the requirements of those applications. Screening economic analyses have shown that NAS battery systems are potentially competitive for some of the single function applications as well as all of the combined function applications, which are described in detail in Chapter 3. The following list briefly summarizes and reiterates key requirements for all applications. Those for which NAS is best suited are enclosed by borders.

Single Function Applications

Application A: Grid Angular Stability (GAS) – mitigation of power oscillations by injection and absorption of real power at periods of 1 to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 20 oscillatory cycles, cumulatively equivalent to a full power discharge (FPD) of 1-second duration and subsequent charge cycle; 1 event per day; 10 events per year. Valued at the cost of alternative solutions.

Application B: Grid Voltage Stability (GVS) – mitigation of degraded voltage by additional reactive power plus injection of real power for durations up to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 1 second FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application C: Grid Frequency Excursion Suppression (GFS) – "prompt" spinning reserve (or load) for mitigating load-generation imbalance. Requires energy storage to discharge real power for durations up to 30 minutes. The reference duty cycle for analysis is standby for infrequent events characterized by 15-minute FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application D: Regulation Control (RC) – system frequency regulation in concert with load following. The reference duty cycle for analysis is characterized by continuous cycles equivalent to 7.5-minute FPD and charge cycle (triangular waveform), 2 cycles per hour deployed with 10 minutes advance notice. Valued at market rates.

Application E: Spinning Reserve (SR) – reserve power for at least 2 hours with 10 minute notice. The reference duty cycle for analysis is standby for infrequent events characterized by 2-hour FPD, 1 event per day, 10 events per year. Valued at market rates.

Application F: Short Duration Power Quality (SPQ) – capability to mitigate voltage sags (e.g., recloser events). The reference duty cycle for analysis is standby for infrequent events characterized by 5 seconds FPD, 1 event per hour, 5 events per day, 100 events per year. Valued at the cost of alternative solutions.

Application G: Long Duration Power Quality (LPQ) – SPQ, plus capability to provide several hours reserve power. The reference duty cycle for analysis is standby for infrequent events characterized by SPQ plus standby for 4 hours FPD, 1 event per year. Valued at the cost of alternative solutions.

Application H: 3-hr Load Shifting (LS3) – shifting 3 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 3-hour FPD, 1 event per day, 60 events per year. Valued at market rates.

Application I: 10-hr Load Shifting (LS10) – shifting 10 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 10-hour FPD, 1 event per day, 250 events per year. Valued at market rates.

Combined Function Applications (In the Order Noted)

Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC)
Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR)
Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR)
Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR)
Application C5: Combined Applications I, D, E (LS10 + RC + SR)

NAS Battery System Compliance With Application Requirements

The NAS battery module performance parameters discussed above were used to develop approximate sizes and operational parameters for systems meeting the application requirements for the selected NAS applications described in the previous section. Key factors in sizing NAS systems include:

- Selection of the type of NAS module and pulse factor (which determines the minimum discharge voltage and therefore the PCS cost). For applications requiring less than 15 seconds (e.g., SPQ), NAS systems use a "discontinuous" (pulsed discharge) IGBT-based PCS that accommodates high currents for brief periods.
- State-of-charge management to ensure that the required power and energy are accessible and that the battery is appropriately recharged
- Thermal management to ensure that cell temperatures are maintained within the acceptable range and that the rate of heat loss is appropriate to the application (e.g., minimized for standby applications).
- Cycle life management to ensure that the system is operated within the service life of equipment, which is especially important for combined function, high cycle applications such as load shifting with regulation control.

Performance aspects of NAS battery systems for the selected applications are described below and summarized in Table 8-5. The reference power for all applications is 10 MW_{ac}.

- Application F: Short Duration Power Quality (SPQ) – This application requires that the system continuously detect and mitigate infrequent PQ events lasting to 2 seconds. Forty (40) NAS PQ50 Modules capable of discharging at a pulse factor of 5 (i.e., 250 kW_{ac} per module) for up to 30 seconds are equipped with a Type III PCS, sized for a minimum discharge voltage of 320 V_{dc} based on discontinuous IGBT converter design. The system will spend virtually its entire life in standby mode. Accordingly, the NAS system employs PQ50 modules designed to limit the rate of heat loss to 2.2 kW_{ac} per module, resulting in the NAS standby efficiency of 99.1%. The projected battery life for this application is 15 years, based on the anticipated shelf life.

Table 8-5
NAS Battery System Compliance With Application Requirements

Applications	Single Function		Combined Function				
	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr	**App I: LS10 -- 10 hr FPD per cycle, 250d/yr**	**App C1: GFS +GAS + GVS + RC**	**App C2: SPQ + LS10 + RC + SR**	**App C3: SPQ + LS3 + RC + SR**	**App C4: LPQ + LS3 + RC + SR**	**App C5: LS10 + RC + SR**
Battery Selection							
Type of Modules	PQ50	E50	PQ50	PQ50	PQ50	E50	E50
Number of Modules	40	258	61	67	67	200	258
Pulse Factor	5.0	1.0	3.3	3.0	3.0	1.0	1.0
Max Charge Voltage	775	1,550	775	775	775	1,550	1,550
Min Discharge Voltage	320	930	320	320	320	930	930
Maximum DOD, %	100%	90%	100%	90%	100%	100%	90%
Cumulative Cycle Fraction	0%	80%	84%	100%	79%	66%	89%
Replacement Interval, yr	15	15	15	15	15	15	15
PCS Selection							
PCS Type (Chapter 5)	III	II	I	III	III	I+SST	II
Duty Cycles							
Grid Support or Power Quality (GS or PQ)							
Power, MW	10		10	10	10	10	
Event Duration, Hr	0.001		0.25	0.001	0.001	4	
Load Shifting (LS)							
Power, MW		10		2.2	3.3	10.0	10.0
Load Shift Energy, MWh/yr		25,000		5,404	600	1,800	25,000
Load Shift Losses, MWh/yr		7,589		1,640	182	546	7,589
Cycle Life Fraction		80%		80%	9%	7%	80%
Regulation Control (RC)							
Power, MW			3.0	3.3	3.3	10.0	10.0
Hours per day, hr			20	16	20	20	20
Days per year, days			355	100	295	295	50
RC, MW-Hours/yr			21,515	5,333	19,667	59,000	10,000
RC Losses, MWh/yr			1,633	405	1,493	4,478	759
Cycle Life Fraction			84%	19%	70%	58%	8%
Spinning Reserve (SR)							
Power, MW				3.3	3.3	10	10.0
SR, MW-Hours				5,306	7,986	23,872	21,920
SR Losses, MWh/yr				20	20	61	61
Cycle Life Fraction				0.98%	0.98%	0.82%	0.63%
Summary System Data							
Standby Hours per Year	8,760	3,260	1,655	1,616	2,420	2,411	2,216
System Net Efficiency, % (See Note)	97.1%	88.1%	97.4%	96.9%	96.9%	91.8%	88.2%
NAS Standby Efficiency, %	99.1%	96.7%	99.6%	99.6%	99.4%	98.1%	97.8%
PCS Standby Efficiency, %	98.0%	100.0%	99.6%	99.6%	99.4%	99.4%	100.0%
System Footprint, MW/sqft (MW/m^2)	0.0041 (0.0441)	0.0011 (0.0123)	0.0033 (0.0354)	0.0031 (0.0335)	0.0031 (0.0335)	0.0014 (0.0152)	0.0011 (0.0123)
NAS Footprint, MW/sqft (MW/m^2)	0.0086 (0.0927)	0.0013 (0.0144)	0.0057 (0.0612)	0.0052 (0.0556)	0.0052 (0.0556)	0.0017 (0.0185)	0.0013 (0.0144)

Note: System net efficiency includes losses for energy conversion and system standby expressed on an annual basis, i.e., one minus inefficiency, where inefficiency equals the ratio of annual energy losses to the product of system rated power times 8760 hours, expressed in percent.

- Application I: 10-hr Load Shifting (LS10) – This application requires that the system provide 10-hour load shifting on a scheduled basis, i.e., prompt PCS response is not required and no PCS standby losses occur. The minimum discharge voltage is 930 V_{dc}. Two hundred fifty-eight (258) NAS E50 Modules capable of discharging at a pulse factor of 1 (i.e., 50 kW_{ac} per module) for up to 8.6 hours and equipped with a Type II PCS will provide load shifting for 10 hours per day at 10 MW_{ac} for 250 days per year. The E50 Module design allows heat loss at a rate of 3.4 kW per module, resulting in the NAS standby efficiency of 96.7%. The projected battery life for this application is 15 years, since cycle life (as measured by the cumulative cycle fraction of 80% at 90% DOD) exceeds shelf life.
- Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC) – This application requires that the system continuously detect and mitigate infrequent GFS, GAS, and GVS events lasting to 15 minutes for GFS. Sixty-one (61) NAS PQ50 Modules capable of discharging at a pulse factor of 3.3 (i.e., 165 kW_{ac} per module) for up to 30 minutes are equipped with a Type I PCS, sized for a minimum discharge voltage of 320 Vdc. In addition, this system will provide RC functions at a power of 3 MW_{ac} for 20 hours per day, 355 days per year. (The large number of cycles is acceptable because the depth-of-discharge for each cycle is only about 1.7%.) Because of the essentially continuous duty cycle associated with RC, the NAS system employs PQ50 modules designed to allow heat loss at a rate of 3.4 kW per module, resulting in the NAS standby efficiency of 99.6%. The projected battery life for this application is 15 years, since cycle life exceeds shelf life (i.e., the cumulative damage fraction is 84% at 100% DOD).
- Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR) – This application requires that the system continuously detect and mitigate infrequent SPQ events lasting to 2 seconds. Sixty-seven (67) NAS PQ50 Modules capable of discharging at a pulse factor of 3 (i.e., 150 kW_{ac} per module) for up to 30 seconds, while delivering 100% depth-of-discharge load shifting cycles, are equipped with a Type III PCS, sized for a minimum discharge voltage of 320 Vdc based on discontinuous IGBT converter design. In addition, this system will provide load shifting for 10 hours per day at 2.2 MW_{ac}, plus RC and SR at 3.3 MW_{ac} for 250 days per year. RC is provided for 16 hours per day, 100 days per year, and SR for the remaining 1592 hours per year. Because of the essentially continuous duty cycle associated with LS10 and RC functions, the NAS system employs PQ50 modules designed to allow heat loss at a rate of 3.4 kW per module, resulting in the NAS standby efficiency of 99.6%. The projected battery life for this application is 15 years, since cycle life (as measured by the cumulative cycle fraction of 100% at 90% DOD) equals shelf life.
- Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR) – This application is the same as Application C2 except the load shifting duty cycle requires 3 hours instead of 10 hours. As for Application C2, sixty-seven (67) NAS PQ50 Modules capable of discharging at a pulse factor of 3 (i.e., 150 kW_{ac} per module) for up to 30 seconds, while delivering 100% depth-of-discharge load shifting cycles, are required, along with a Type III PCS, sized for a minimum discharge voltage of 320 Vdc based on discontinuous IGBT converter design. In addition to load shifting for 3 hours per day at 3.3 MW_{ac} for 60 days per year, this system provides RC and SR at 3.3 MW_{ac}. RC is provided for 20 hours per day, 295 days per year, and SR for the remainder of the year. Because of the essentially continuous duty cycle associated with RC, the NAS system employs PQ50 modules designed to allow heat loss at a rate of 3.4 kW per module, resulting in the NAS standby efficiency of 99.4%.

The projected battery life for this application is 15 years, since cycle life (as measured by the cumulative cycle fraction of 79% at 100% DOD) exceeds shelf life.

- Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR) – This application requires that the system continuously detect and mitigate infrequent SPQ events lasting to 2 seconds, as well as full outage protection up to 4 hours. Two hundred (200) NAS E50 Modules capable of discharging at a pulse factor of 1 (i.e., 50 kW_{ac} per module) for up to 8.6 hours are equipped with a Type I PCS plus a static switch (SST), sized for a minimum discharge voltage of 930 V_{dc}. In addition, this system will provide load shifting for 3 hours per day at 10 MW_{ac} for 60 days per year, plus RC and SR at 10 MW_{ac}. RC is provided for 20 hours per day, 295 days per year, and SR for the remainder of the year. The E50 Module design allows heat loss at a rate of 3.4 kW per module, resulting in the NAS standby efficiency of 98.1%. The projected battery life for this application is 15 years, since cycle life (as measured by the cumulative cycle fraction of 66% at 100% DOD) exceeds shelf life.
- Application C5**:** Combined Applications I, D, E (LS10 + RC + SR) – This application requires that the system provide 10-hour load shifting, regulation control and spinning reserve functions on a scheduled basis using a Type II PCS, i.e., prompt PCS response is not required and no PCS standby losses occur. Two hundred fifty-eight (258) NAS E50 Modules capable of discharging at a pulse factor of 1 (i.e., 50 kW per module) for up to 8.6 hours equipped with a programmable PCS will provide load shifting for 10 hours per day at 10 MW_{ac} for 250 days per year , plus RC and SR at 10 MW_{ac}. RC is provided for 20 hours per day, 50 days per year, and SR for the remainder of the year. The E50 Module design allows heat loss at a rate of 3.4 kW per module, resulting in the NAS standby efficiency of 97.8%. The projected battery life for this application is 15 years, since cycle life (as measured by the cumulative cycle fraction of 89% at 90% DOD) exceeds shelf life.

Benefit and Cost Analyses

NAS Battery Pricing and Integrated System Costs

Since April 2003, NGK and TEPCO have established the full commercialization of the NAS battery in Japan, including commercial-scale manufacturing facilities, firm prices, commercial warranties and full service options. Market introduction for North America is underway through the development of select high value demonstration projects. Current nominal unit prices for utility scale applications in North America are in the range of $85K to $95K per module, depending on module type, number of modules, site location, etc. For the Handbook's reference deployment date of 2006 and rating of 10MW_{ac}, nominal unit prices are based on NGK's planned expansion of their manufacturing capacity. For any replacement modules over the assumed 20 year project lifetimes, fully mature price estimates are applied. The resultant NAS PQ and PS module prices applied for the benefit-cost assessments herein are:

NAS Module	2006 Prices, K$	Mature Prices, K$
E50	$75	$55
G50	$68	$50
PQ50	$75	$55

In addition to the NAS battery modules, the related NAS scope of supply includes the battery management system, DC circuit breakers (PQ modules only), exterior enclosures, import duties and fees, shipment from Japan to an inland site, plus technical support for system integration, installation and startup.

The cost of integrated NAS systems is obtained by combining the cost of the NAS battery scope of supply with the appropriate PCS and BOP costs as described in Chapter 5. The PCS and BOP costs shown in Table 8-6 are based on the methodology described in Chapter 5. NAS systems for short duration discharge applications (e.g., SPQ) use Type III "discontinuous" IGBT-based PCS which accommodate high currents for brief periods at reduced cost compared to continuous ratings. Since the cost of exterior enclosures is included in the NAS battery scope of supply, the cost of exterior space and foundations for NAS batteries is included at $20/sqft.

Table 8-6
Capital and Operating Costs for NAS Battery Systems

Applications	Single Function		Combined Function				
	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr	App I: LS10 -- 10 hr FPD per cycle, 250d/yr	App C1: GFS +GAS + GVS + RC	App C2: SPQ + LS10 + RC + SR	App C3: SPQ + LS3 + RC + SR	App C4: LPQ + LS3 + RC + SR	App C5: LS10 + RC + SR
NAS Battery Capacity, MWh_{ac}	0.006	100	2.50	22	10	40	100
PCS Initial Cost, $/kW	153	204	449	202	202	289	204
BOP Initial Cost, $/kW	100	100	100	100	100	100	100
NAS Battery Initial Cost, $/kW	305	1,964	461	508	508	1,523	1,964
NAS Battery Initial Cost, $/kWh	550,000	196	1,845	235	508	381	196
Total Capital Cost, M$	5.6	22.7	10.1	8.1	8.1	19.1	22.7
O&M Cost – Fixed, $/kW-year	13.8	51.2	23.1	19.2	19.2	43.2	51.2
O&M Cost– Variable, $/kW-year	9.6	13.4	2.6	2.6	3.9	8.1	9.1
NPV NAS Disposal Cost, $/kW	6.7	43.2	10.1	11.2	11.2	33.5	43.2

Note: The total initial cost may be calculated in two ways:
1. By mutiplying the sum of PCS, BOP and Battery initial costs expressed in $/kW by the reference power,
2. OR by mutiplying the sum of PCS and BOP expressed in $/kW by the reference power and then adding the product of Battery Initial cost expressed in $/kWh and the Battery Capacity

Fixed O&M costs for the PCS are based on $2/kW as required by provisions in Chapter 5, plus NAS battery maintenance in accordance with the vendor. 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
- Retorquing terminal connections
- 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 1000 cycles)

Based on experience gained at TEPCO demonstration projects, the levelized annual labor for NAS battery installations of 20 modules and greater averages 3 hours per module. Fixed O&M costs are based on labor costs of $50 per hour (or $150 per module per year). In addition, an annual allowance for property taxes and insurance, based on 2% of the total initial capital costs, is included in the fixed O&M costs.

Variable O&M costs for the system include the cost of electrical losses to maintain the PCS during hot standby intervals and the NAS operating temperature regime. An allowance for NAS battery disposal costs is included at $3,750 per module at the end of battery life, including the cost of shipping, recycling useable material and disposition of sodium residuals.

Lifecycle Benefit and Cost Analysis for NAS Battery Systems

Further insight to the value of energy storage can be gained through lifecycle cost analyses using a net present value (NPV) methodology and comparison with alternatives. For the convenience of the reader, the financial parameters and electric rate structure set forth in Chapters 4 and 5 and used in the analyses are summarized in Table 8-7 and Table 8-8.

Table 8-7
Financial Parameters

Dollar Value	2003
System Startup	June 2006
Project Life, years	20
Discount Rate (before tax), %	7.5
Property Taxes & Insurance, %/year	2
Fixed Charge Rate, %/year	9.81

Table 8-8
Electric Rates

Load Shifting On Peak Period	3	10
Number Cycles per year	60	250
On-Peak Energy, $/MWh	120	80
Off-Peak Energy, $/MWh	20	
Yearly Average Energy Charge, $/MWh	38	
Regulation Control, $MW-Hour (power), $/MWh	16	
Spinning Reserve, $MW-Hour (power), $/MWh	3	
Transmission Demand Charge, $/kW-mo	5	

The results of lifecycle cost benefit analyses of select NAS battery applications are summarized in Table 8-9 and discussed below. The bases and methodology used in valuing energy storage applications is described in detail in Chapter 4. The details of the cost benefit analysis for each application are discussed below.

Table 8-9
Summary of Benefit and Cost Analyses of NAS Battery Systems

	Single Function		Combined Function				
Applications	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr	App I: LS10 -- 10 hr FPD per cycle, 250d/yr	App C1: GFS +GAS + GVS + RC	App C2: SPQ + LS10 + RC + SR	App C3: SPQ + LS3 + RC + SR	App C4: LPQ + LS3 + RC + SR	App C5: LS10 + RC + SR
Alt Solution Value, $/kW	1,000	750	750	1,500	1,500	2,000	750
Initial Installed Cost, M$	5.58	22.68	10.10	8.09	8.09	19.12	22.68
Total Costs, M$	(8.4)	(31.9)	(13.3)	(11.0)	(11.1)	(26.4)	(31.5)
Total Benefits, M$	10.0	37.6	10.4	20.2	18.9	31.8	39.5
Benefit to Cost Ratio	1.20	1.18	0.78	1.83	1.70	1.20	1.26
NPV, M$	1.6	5.7	(3.0)	9.2	7.8	5.4	8.1
NAS Module	PQ50	E50	PQ50	PQ50	PQ50	E50	E50
Number of Modules	40	258	61	67	67	200	258
NAS 2006 Price, K$/module	75	75	75	75	75	75	75
NAS Price for NPV=0, K$/module	109	93	34	189	172	97	101

- Application F: Short Duration Power Quality (SPQ) – This application was evaluated on the assumption that an alternative solution capable of mitigating SPQ events can be obtained for net capitalized costs of about $1000/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 8-5, this application yields a NPV of $1.6 million for an initial investment of about $5.6 million on this basis. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 8-11 illustrates the change in NPV over a range of $500 to $1500/kW and shows that NAS systems will compete favorably against alternative solutions with net capitalized costs in excess of about $840/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of NAS PQ50 modules were increased from $75,000 to $109,000 per module, the NPV would equal zero, i.e., costs and benefits would be equal.

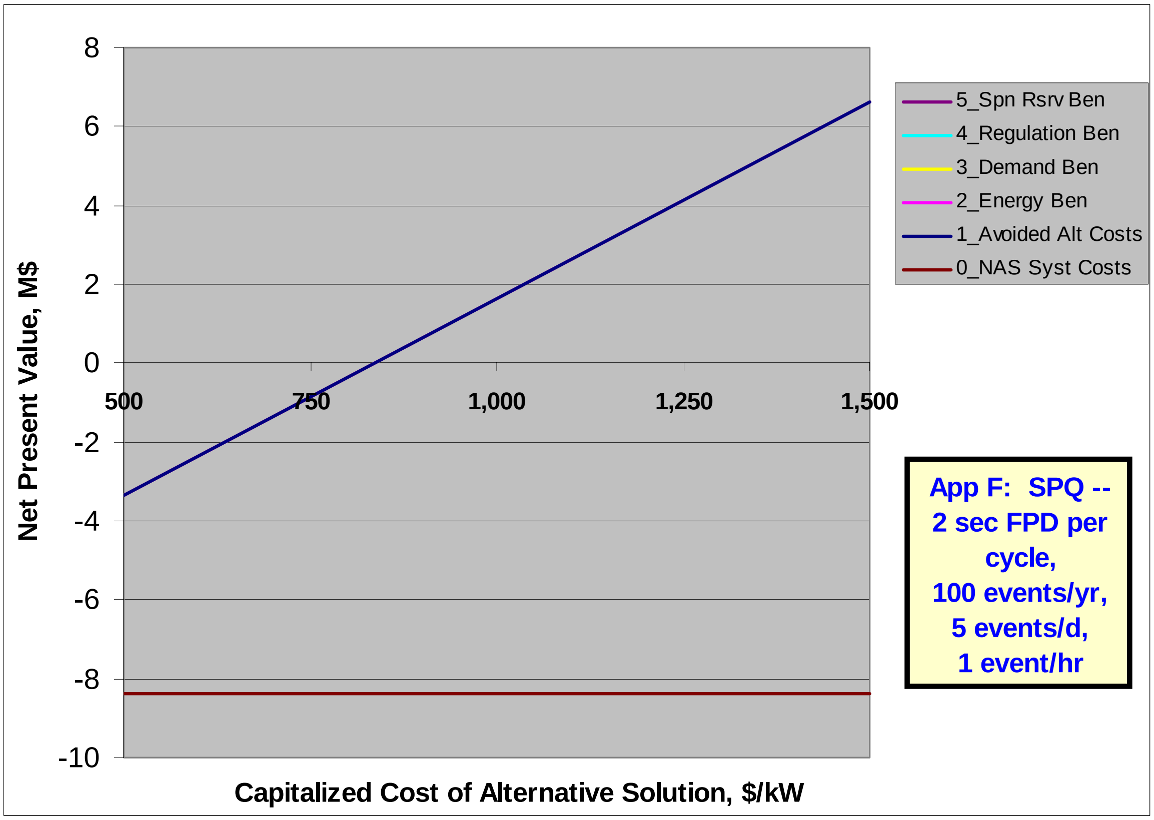

Figure 8-11
Application F: NAS System NPV vs Cost of Alternative Solution

- Application I: 10-hr Load Shifting (LS10) – This application was evaluated on the assumption that an alternative solution capable of avoiding upgrade costs can be obtained for net capitalized costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. In addition, the benefits of market rates for on-peak energy and demand charges and off-peak energy rates to recharge the battery are included. As shown in Table 8-5, this application yields a NPV of $5.7 million for an initial investment of about $22.7 million. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 8-12 illustrates the change in NPV over a range of $500 to $1000/kW and shows that NAS systems will compete favorably against alternative solutions over this range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of NAS PQ50 modules were increased from $75,000 to $93,000 per module, the NPV would equal zero, i.e., costs and benefits would be equal at the alternative solution value of $750/kW.

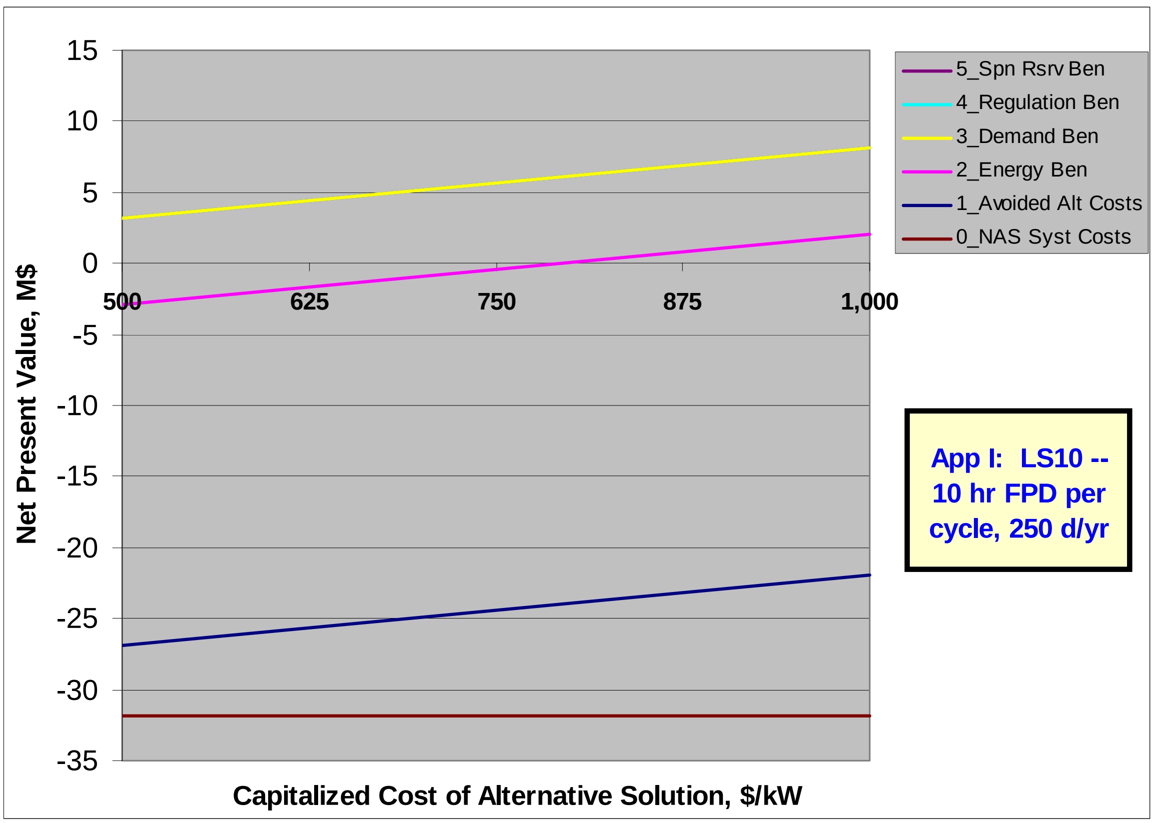

Figure 8-12
Application I: NAS System NPV vs Cost of Alternative Solution

- Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC) – This application was evaluated on the assumption that an alternative solution capable of mitigating GFS, GAS and GVS events can be obtained for capitalized acquisition and operating costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rate for regulation control is also included in the valuation. As shown in Table 8-5, this application yields a negative NPV of ($13.3) million for an initial investment of about $10.1 million. However, the benefit to cost ratio is about 0.8, and NAS is deemed to be marginally competitive in that it should be considered in circumstances where its intrinsic properties (e.g., its relatively small space requirements) are of high value. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 8-13 illustrates the change in NPV over a range of $500 to $1000/kW, as well as the incremental value of regulation control, and shows that NAS systems will only compete favorably against alternative solutions with net capitalized costs somewhat greater than $1000/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of NAS PQ50 modules were decreased from $75,000 to $34,000 per module, the NPV would equal zero, i.e., costs and benefits would be equal, at the alternative solution value of $750/kW.

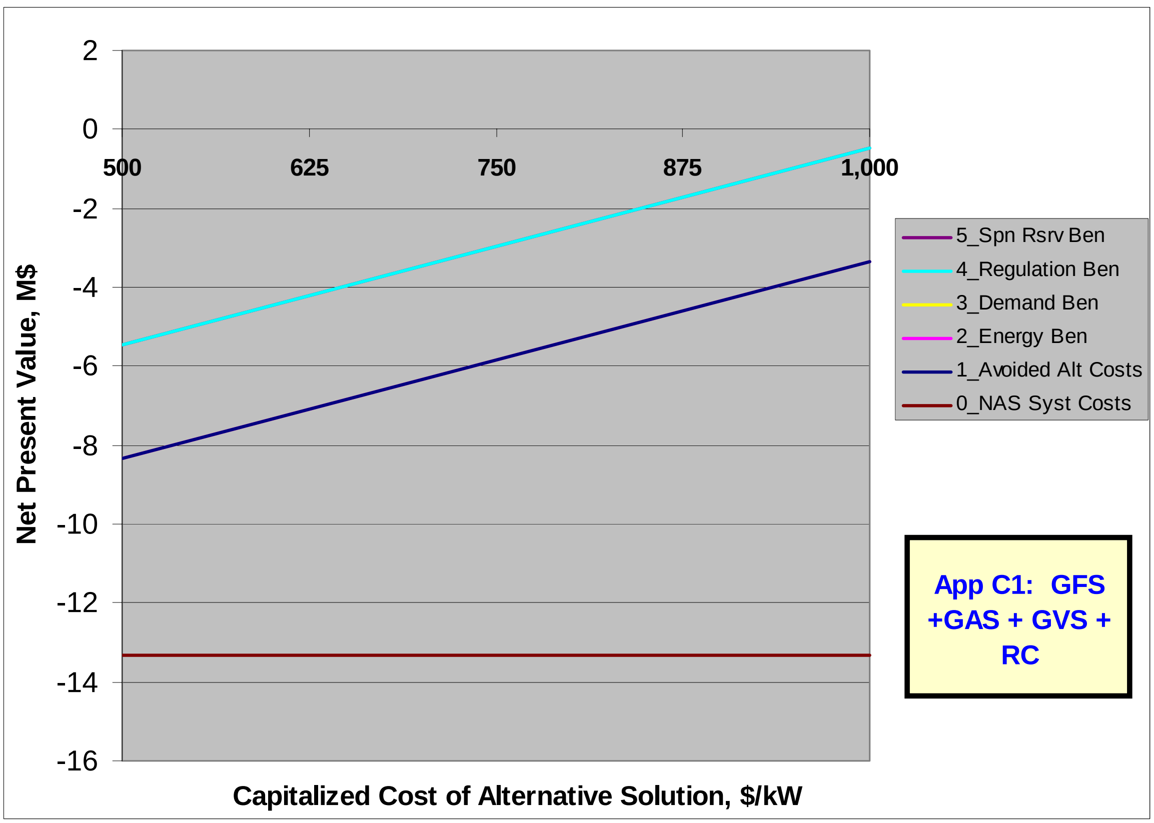

Figure 8-13
Application C1: NAS System NPV vs Cost of Alternative Solution

- Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating SPQ events, plus avoid LS10 related upgrade costs, can be obtained for net capitalized costs of about $1500/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 10-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Table 8-5, this application yields a NPV of $9.2 million for an initial investment of about $8.1 million on this basis. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 8-14 illustrates the change in NPV over a range of $1000 to $2000/kW, as well as the incremental value of load shifting (both energy and demand), regulation control and spinning reserve functions. With these value elements, NAS systems will compete very favorably against alternative solutions with net capitalized costs over the entire range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of NAS PQ50 modules were increased from $75,000 to 189,000 per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $1500/kW.

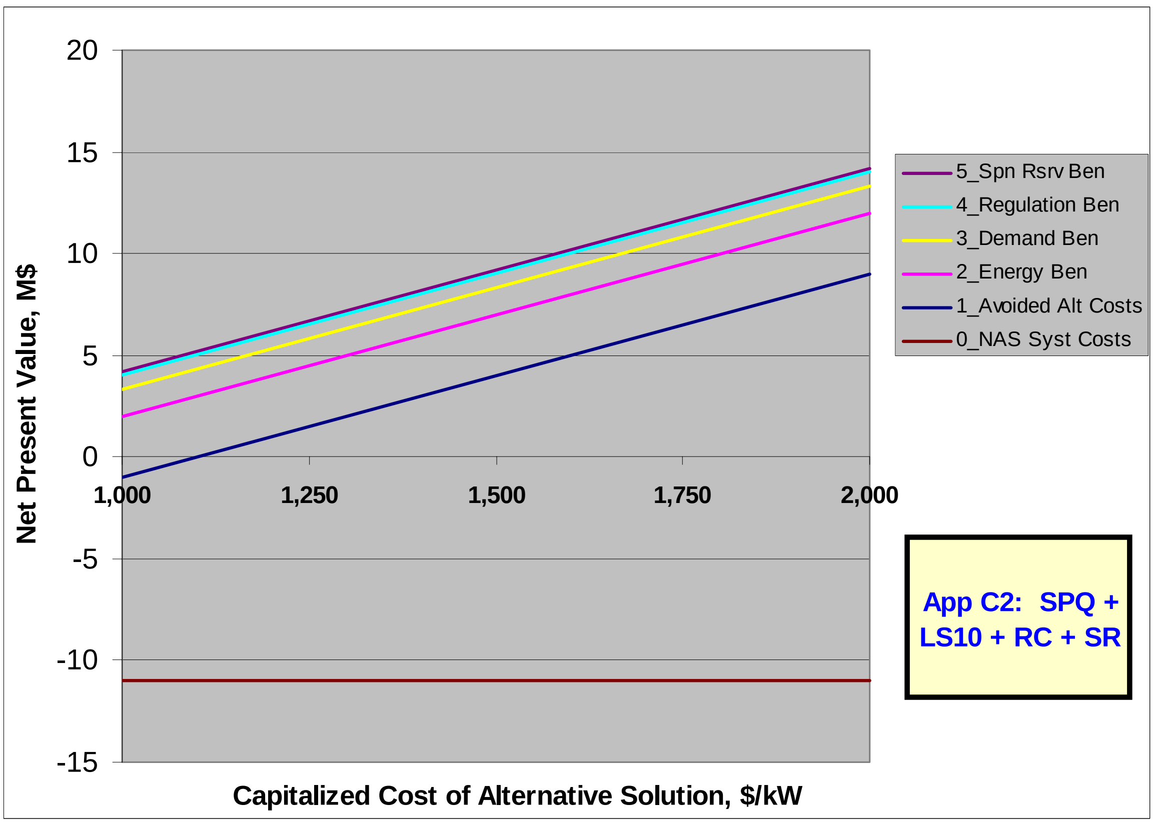

Figure 8-14
Application C2: NAS System NPV vs Cost of Alternative Solution

- Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating SPQ events, plus avoided LS3 related upgrade costs, can be obtained for net capitalized costs of about $1500/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 3-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Table 8-5, this application yields a NPV of $7.8 million for an initial investment of about $8.1 million on this basis. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 8-15 illustrates the change in NPV over a range of $1000 to $2000/kW, as well as the incremental value of load shifting (both energy and demand), regulation control and spinning reserve functions. With these value elements, NAS systems will compete very favorably against alternative solutions over the entire range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of NAS PQ50 modules were increased from $75,000 to $172,000 per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $1500/kW.

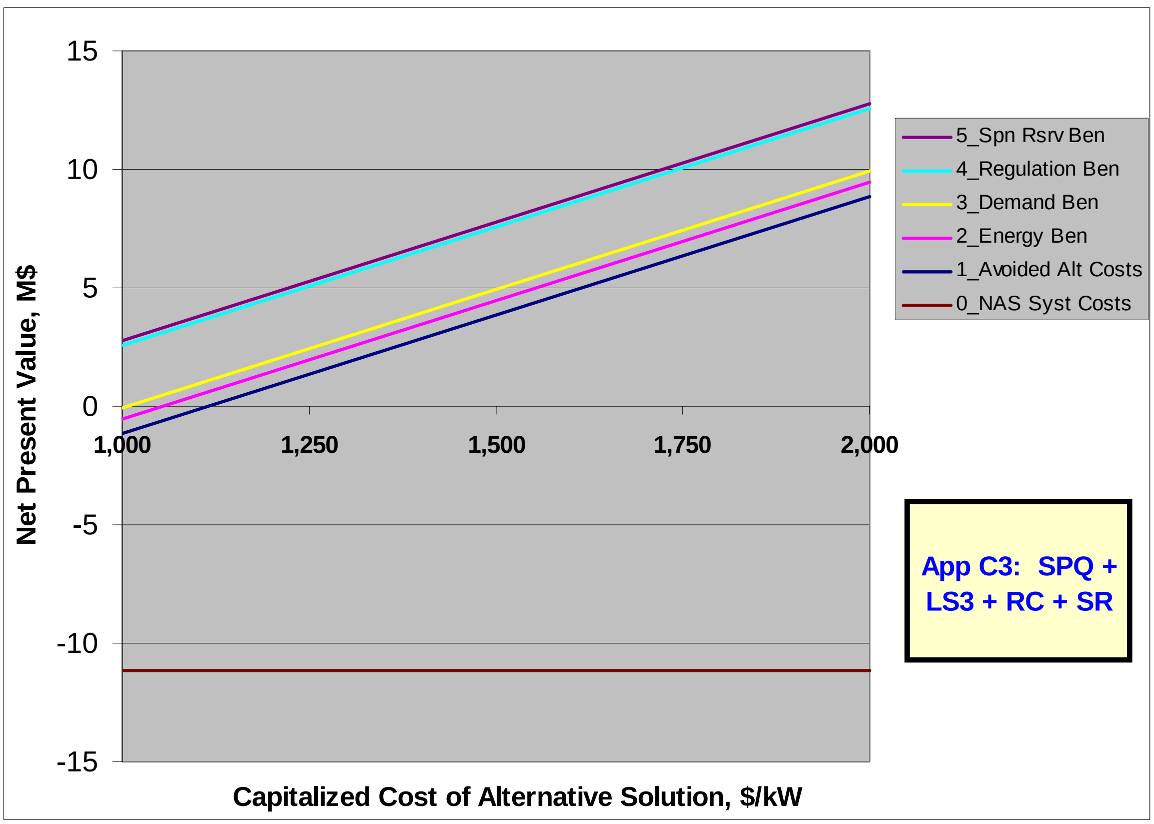

Figure 8-15
Application C3: NAS System NPV vs Cost of Alternative Solution

- Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating LPQ events, plus avoided LS3 related upgrade costs, can be obtained for net capitalized costs of about \$2000/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 3-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Table 8-5, this application yields a NPV of \$5.4 million for an initial investment of about \$19.1 million on this basis. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 8-16 illustrates the change in NPV over a range of \$1500 to \$2500/kW, as well as the incremental value of load shifting (both energy and demand), regulation control and spinning reserve functions. With these value elements, NAS systems will compete favorably against alternative solutions over this range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of NAS E50 modules were increased from \$75,000 to \$97,000 per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at \$2000/kW.

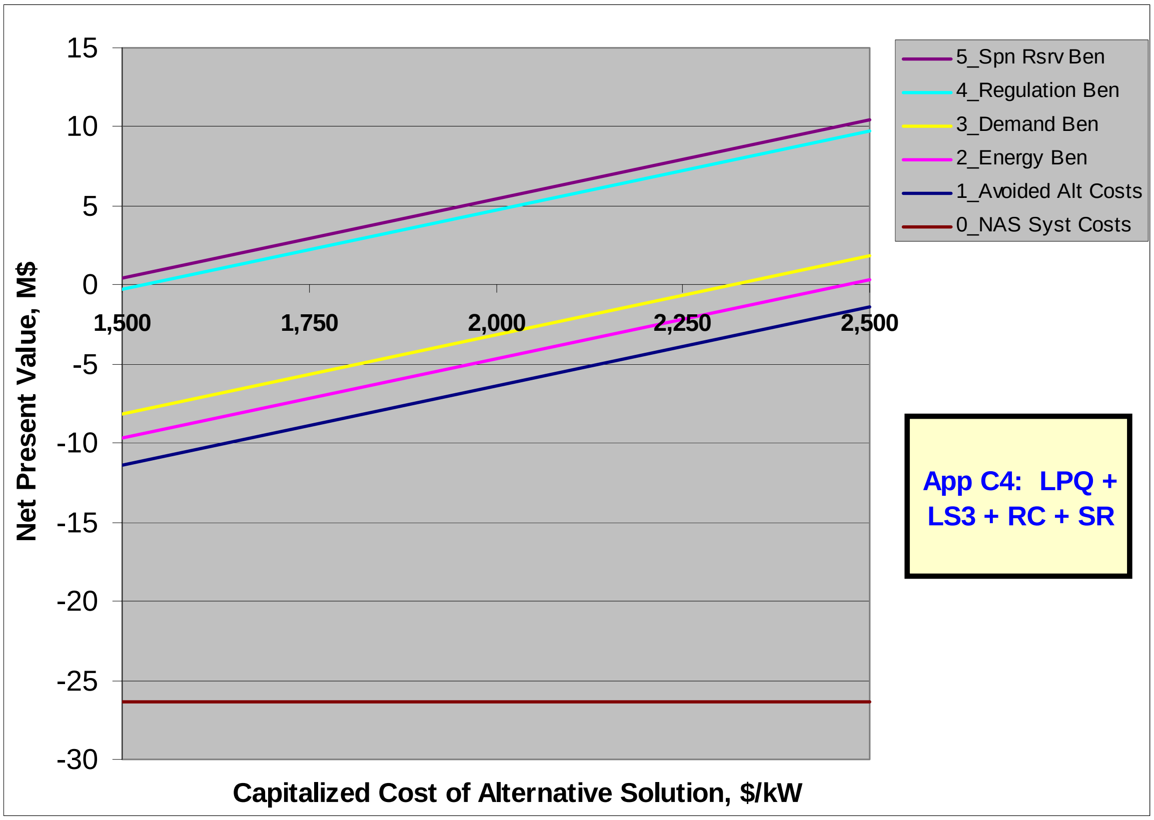

Figure 8-16
Application C4: NAS System NPV vs Cost of Alternative Solution

- Application C5: Combined Applications I, D, E (LS10 + RC + SR) – This application was evaluated on the assumption that an alternative to LS10 related upgrade costs can be obtained for net capitalized costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. In addition, market rates for 10-hour load shifting, regulation control, and spinning reserve are included in the valuation. As shown in Table 8-5, this application yields a NPV of $8.1 million for an initial investment of about $22.7 million. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 8-17 illustrates the change in NPV over a range of $500 to $1000/kW and shows that NAS systems will compete favorably against alternative solutions over this range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of NAS PQ50 modules were increased from $75,000 to $101,000 per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $750/kW.

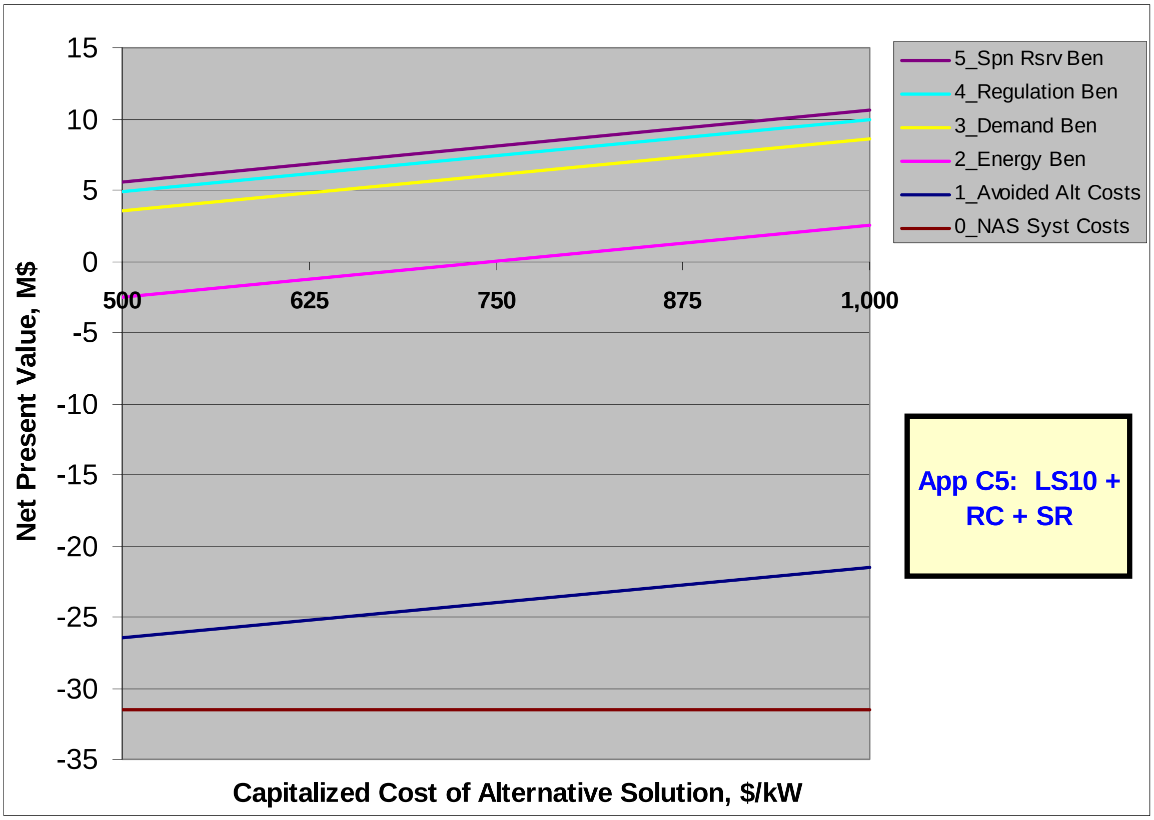

Figure 8-17
Application C5: NAS System NPV vs Cost of Alternative Solution

Interpreting Results from Benefit-Cost Analyses

In general, NAS battery systems are expected to be competitive for high value, single and combined function applications of a few seconds or several hours. NAS is penalized as a result of high PCS cost by its low minimum discharge voltage for pulse durations greater than can be accommodated by "discontinuous" IGBT-based PCS.

The reader is reminded that the foregoing analyses are intended as a guide to the initial consideration of energy storage options, and that these analyses are based on representative electric rates and costs for alternative solutions as described in Chapter 4. The assumptions used herein should be reviewed in light of project specific applications, alternative solutions, electric rates and financial parameters.

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9
ZINC-BROMINE BATTERIES

Introduction

Rechargeable zinc battery technology has long been considered attractive for large-scale energy storage systems, because of the high energy density and relatively low cost of zinc. Similarly, flow batteries are recognized as a favorable technology for large systems, because they are eminently scalable and allow a great deal of flexibility in system design. The zinc-bromine flow battery is a combination of these two technologies, with significant potential for use in large-scale utility applications.

The zinc-bromine battery has undergone major development, characterization, and field testing efforts. General consensus is that the technology, at large, is ready for the product stage for some utility applications, particularly load-leveling and other applications requiring high efficiency and high energy density without the necessity of very high power density.

However, available zinc-bromine products are still at a relatively early level of maturity. It will take some improvements in product design and in manufacturing, as well as years of experience in the field, before these systems are commercially mature.

Description

The first zinc-bromine rechargeable battery was patented in 1885, but commercial development was slow because of problems associated with both electrodes. Zinc electrodes are notoriously difficult to recharge because of their tendency to form dendrites on charge, which can cross the electrolyte and connect with the opposite electrode. Bromine, meanwhile, is highly soluble in the aqueous electrolyte, leading to crossover and direct reaction with the zinc.

Two notable development programs arose out of the increased interest in energy storage technologies in the mid-1970s. The first, developed by Gould, Inc., was later developed by the Energy Research Corporation (now Evercel) in the 1980s. The other, developed by the Exxon Research and Engineering Company, was licensed by Exxon to several manufacturers, including Johnson Controls, Inc. (JCI), Studiengesellschaft für Energiespeicher und Antriebssysteme (SEA), Toyota Motor Corporation, Meidensha Corporation, and Sherwood Industries of Australia [1].

The technology continued to show a great deal of potential in electric vehicle applications, but this market faded as electric vehicle efforts declined in the mid 1990s. Development for utility applications has continued through the 1990s up to the present day. At present, only one major zinc-bromine developer, ZBB Energy Corporation, is operating at a high level of activity.

Chemistry

Zinc-bromine batteries are of a type known as *flow batteries,* in which one or both active materials is in solution in the electrolyte at all times. In the case of zinc bromine, the zinc is solid when charged but dissolved when discharged, while the bromine is always dissolved in the aqueous electrolyte.

The basic zinc-bromine cell configuration is shown in Figure 9-1. Each cell is composed of two electrode surfaces and two electrolyte flow streams separated by a microporous film. The positive electrolyte is called a *catholyte*; the negative is correspondingly the *anolyte*. Both electrolytes are aqueous solutions of zinc bromide ($ZnBr_2$).

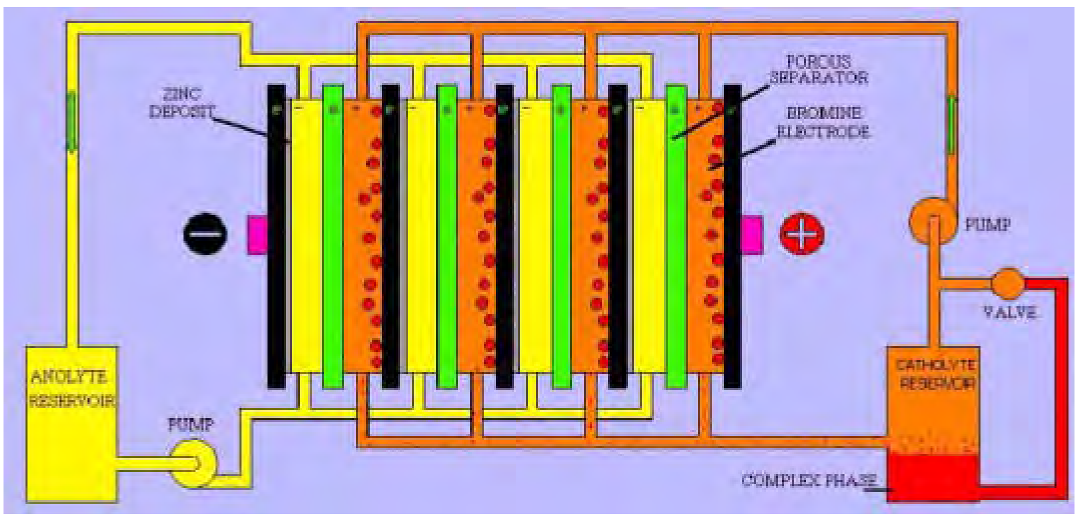

Figure 9-1
Zinc-Bromine Cell Configuration *(Courtesy ZBB Energy Corporation)*

The electrochemistry of the zinc-bromine cell can be described as follows:

Positive: $$Br_2(aq) + 2e^- \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} 2Br^-(aq) \qquad \textbf{Eq. 9-1}$$

Negative: $$Zn \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} Zn^{2+}(aq) + 2e^- \qquad \textbf{Eq. 9-2}$$

During charge, elemental zinc is plated onto the negative electrode. Elemental bromine is formed at the positive electrode. Ideally, this elemental bromine will remain only in the positive electrolyte. The microporous separator allows zinc ions and bromide ions to migrate to the opposite electrolyte flow stream for charge equalization. At the same time, it inhibits elemental bromine from crossing over from the positive to the negative electrolyte, reducing self-discharge due to direct reaction of bromine with zinc.

The reactants and products in the above equations are actually approximations for the true state of zinc, bromide, and bromine in solution. Both zinc and bromide ions form complex ions that are more stable in aqueous solution. Dissolved elemental bromine interacts with bromide ions to form polybromide ions. Complexing agents, usually quaternary ammonium salts, are added to the electrolyte to cause these polybromide ions to form a low-solubility liquid phase. This phase is removed in the positive electrolyte reservoir and stored separately, effectively reducing the concentration of bromine in the electrolyte and, therefore, reducing the incidence of crossover and self-discharge [1].

The cell electrodes are composed of carbon plastic, and are designed to be bipolar. This means that a given electrode serves both as the cathode for one cell and the anode for the next cell in series. Carbon plastic must be used because of the highly corrosive nature of bromine. The positive electrode surface is coated with a high-surface-area carbon to increase surface area.

As described above, the two electrolytes differ only in the concentration of elemental bromine; both should have the same zinc and bromide ion concentrations at any given time during the charge/discharge cycle. This can best be accomplished through the use of an ion-selective membrane as the separator. This membrane would allow the passage of zinc and bromide ions without allowing elemental bromine or polybromide to pass through. In practice, such membranes have proven more costly and less durable than nonselective membranes. For these reasons, nonselective microporous membranes are usually used for the separator.

The electrolyte is circulated for a number of reasons. Circulation serves to quickly remove bromine (in the form of polybromide) from the positive electrode, freeing up the surface area for further reaction. It also allows the polybromide to be stored in a separate tank to minimize self-discharge. On the negative electrode, the flow inhibits the formation of zinc dendrites. Finally, the circulation simplifies thermal management, through the use of a heat exchanger. The two electrolytes can flow in the same direction within a cell (co-current), or in opposite directions (counter-current), depending on the design.

Note that the cells are constructed in series electrically, but in parallel hydraulically. This means that there are leakage currents, called shunt currents, between cells through the electrolyte. These currents can lead to a number of problems. Shunt currents can be minimized through appropriate design of the hydraulic channels to lengthen the path such currents would follow. This design increases the pressure drop in the piping and makes the electrolytes harder to pump. Battery design requires a trade-off to find the optimum point between small shunt currents and small pressure drop.

Battery Construction

The zinc-bromine battery has three main subsystems:

- The cell stacks

- Electrolyte containment
- Electrolyte circulation systems

Most of the components of the cell stack are composed of thermoplastics, manufactured by extrusion or injection molding. The stack is assembled in such a way as to eliminate leakage. Historically, this has been done using gaskets or adhesives, or vibration welding. Figure 9-2 shows an exploded diagram of a cell stack.

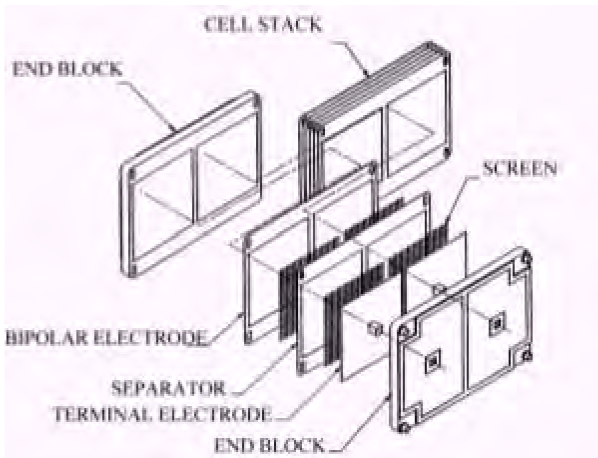

Figure 9-2
Exploded Diagram of Zinc-Bromine Cell Stack (Courtesy ZBB Energy Corporation)

As seen in Figure 9-1, the electrolyte circulation systems each consist of a reservoir, at least one pump, and tubing to each individual cell. The positive electrolyte reservoir is specially constructed to collect the complexed polybromide. A valve ensures that this polybromide is not recirculated during charge. During discharge, the valve opens, allowing the polybromide into the system.

The negative electrolyte loop sometimes contains a heat exchanger for thermal management of the battery. The heat exchanger must be specially constructed to survive the extremely corrosive electrolyte; plastic is often used for this purpose.

Performance Characteristics

Discharge and Charge Voltage

The zinc-bromine cell has a nominal voltage of 1.8 V_{dc}. During charge, the voltage will rise up to about 2 V_{dc}/cell, and the cutoff voltage for 100% discharge is 0.5 to 1.0V_{dc}/cell. Figure 9-3 shows a typical voltage curve for a charge and discharge cycle of a 60-cell zinc-bromine stack.

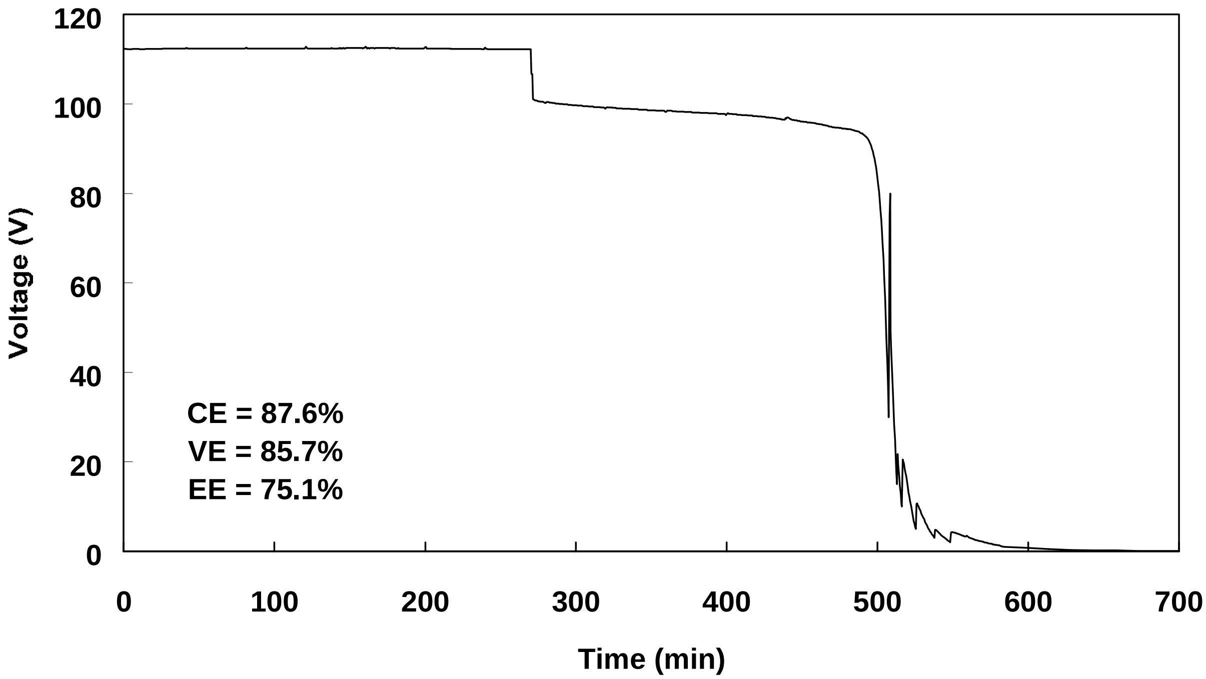

Figure 9-3
Charge and Discharge Voltage Curve for a 60-Cell Zinc-Bromine System (Courtesy ZBB Energy Corporation)

The battery can be discharged down to zero V_{dc}/cell, at which point the negative plate is completely free of zinc. This operation is called *stripping*. Stripping is desirable to ensure that zinc deposition during charge is smooth across the electrode and across all cells. It is usually recommended that a stripping cycle be performed every 5 to 10 cycles to ensure high efficiency.

Efficiency

Zinc-bromine batteries exhibit high efficiency relative to other battery systems. In tests performed at Sandia National Labs on several batteries over a large number of cycles, average round-trip energy DC-DC efficiency was consistently found to be between 70% and 80% [4, 5].

Energy efficiency is a function of several variables, including design variables such as pump and pipe sizing, as well as operational variables such as operating temperature, charge and discharge current, and frequency of stripping. In well-designed, consistently manufactured systems, the DC-DC efficiency is likely to exceed 70% and may be as high as 75%.

Self-Discharge

Self-discharge is the term used to describe energy losses during the period between charge and discharge, when the battery is fully charged. This effect is generally undesirable, since it causes a decrease in the energy stored, reduces the efficiency, and generates heat in the cells.

In zinc-bromine batteries, self-discharge arises largely from bromine cross-over to the anode side. Testing has shown the effect to be about 1% per hour on a watt-hour basis [1]. Self-discharge can be minimized by stopping electrolyte circulation during stand periods, limiting the degree of crossover to bromine that is in the cell when circulation ceases. This also reduces the effectiveness of thermal management systems, however. Testing has shown that significant temperature rises can occur as a result of self-discharge during stand [5]. For this reason, most control systems circulate the electrolyte intermittently during stand.

There are other, less-obvious sources of self-discharge, including the corrosion of zinc through reaction of water. This corrosion produces zinc oxide and hydrogen. There is conflicting evidence as to whether this effect is significant; it seems to be dependent on the design of the cell and the negative electrode [1, 5]. In cases where hydrogen production is significant, there should be provisions to account for venting of hydrogen, as well as replacement of water lost in this manner.

Effects of Temperature

Zinc-bromine systems are designed to operate at or slightly higher than room temperature, between 20ºC and 50ºC. While temperature has an effect on the performance zinc-bromine batteries, the magnitude of the effect is reduced by counteracting intrinsic forces within the cell, and by the thermal design of the battery.

Battery efficiency is a weak function of temperature. At higher temperatures, greater ionic mobility in the electrolyte results in lower resistivity in the electrolyte, improving voltaic efficiency. Bromine cross-over is also increased, however, reducing coulombic efficiency. These effects tend to cancel each other out. The same is true of operation at lower temperature.

The inclusion of the circulating electrolyte and heat exchanger in the zinc-bromine design makes the system better at rejecting waste heat than many other storage battery systems. This means that temperature effects are slower to manifest than they are with other batteries. However, this also means that the batteries are susceptible to special failure modes, such as pump failure.

Degradation and Life Expectancy

The most common factor in degradation and eventual failure of zinc-bromine batteries arises from the extremely corrosive nature of the elemental bromine electrolyte. This substance tends to attack all the components of the zinc-bromine system that are exposed to it. Past failure modes have included damaged seals, corrosion of current collectors, and warped electrodes. The active materials themselves do not degrade. The significance of this fact is that the lifetime is not strongly dependent on the number of cycles or the depth of discharge, but on the number of hours that the system has been operational.

Significant progress has been made with materials for carbon electrodes and other components. At present, 2000 cycles, or about 6000 hours of continuous operation, is considered a reasonable estimate of lifetime for zinc-bromine systems [1].

System Design

Zinc-bromine system design is somewhat dependent on the philosophy of the designer. The principal sizing variables are voltage, power rating, and energy capacity. The voltage of a system is dependent on the number of cells in series in the stack. The power rating of a stack is dependent on the electrode area (which determines current density) and the number of stacks in parallel, as well as the stack voltage.

The energy capacity is dependent on both the size of the cells and the size of the electrolyte storage tanks. The zinc negative electrode is limited by the thickness of the negative side of the cell; particularly, the zinc plate must not become so thick that it interferes with electrolyte flow and impedes operation. A bigger factor in determining energy capacity, however, is the size of the electrolyte tanks, since this determines the amount of active material which is available for charge and discharge.

It is possible to produce a system meeting the technical requirements from a single, large stack of the required voltage and power characteristics, together with a single pair of large electrolyte storage tanks that provide sufficient energy capacity. This method requires manufacturing a new design for each installation, however.

To improve flexibility and reduce cost, most manufacturers have instead approached systems design with a modular approach. In this approach, modules of a fixed size are arranged in series-parallel combinations to produce the desired voltage, power rating, and energy capacity. The effectiveness of this approach depends on the size of the module. Modules that are too large result in systems that are significantly oversized; modules that are too small result in large packaging factors and increased system complexity.

Safety and environmental characteristics should also be considered when designing a large system. The most prominent safety hazard in the zinc-bromine system is elemental bromine. Liquid bromine, should it escape, is hazardous to personnel, particularly when inhaled. This danger is minimized by ensuring that bromine is more common in the complexed polybromide state than as free bromine. The polybromide form is significantly less dangerous. Nonetheless, an electrolyte spill will result in the slow release of bromine vapors, and any zinc-bromine facility must be equipped to detect such a spill and be prepared to take appropriate steps to handle it.

In theory, there are no gases released by zinc-bromine systems in normal operation. In some cases, however, hydrogen generation has occasionally been observed in zinc-bromine systems.

Depending on the size of the system, vendor recommendations, and general safety procedures, the installation of a hydrogen sensor may be required.

During normal operation, zinc-bromine batteries do not present unusual environmental hazards. They do, however, contain materials which can become environmental contaminants. Bromine is a toxic material and should be recovered in the event of a spill or when the unit is decommissioned. Zinc-bromide is a corrosive and should be dealt with appropriately. Zinc is considered a transition-metal contaminant in some locales, and should be properly recovered when the unit is decommissioned.

Operation and Maintenance

Zinc-bromine batteries require some supervision and maintenance, as do all batteries. Sophisticated controls are usually built into zinc-bromine systems to ensure that the battery is operating properly, and will alert operators if there is a problem. Such problems may include pump failures, electrolyte leaks, or cell voltage imbalance.

The most common maintenance function is the stripping cycle, which is usually performed once every 5 cycles. This translates to about once a week in diurnal load-leveling applications. This function, too, can be automated with a good control system.

The addition of water to the electrolytes to replace water loss to gassing is generally not required for zinc-bromine systems. While gassing has been observed in some systems, the degree of water loss was relatively small. Nonetheless, it is possible to add water to the circulating electrolyte to compensate for water loss, should it become necessary.

The stack components have limited life, usually estimated at about 2000 cycles of 100% DOD. After this time, the stack must be replaced to ensure proper performance. For a diurnal load-leveling application that operates 5 times a week, this would mean stack replacement would occur after about 7 years. Manufacturers have not quoted lifetimes for the circulating system (including pumps) or for the electrolyte reservoirs.

Technology Status

Notable Vendors and Developers

While many companies have worked with zinc-bromine batteries, only one, ZBB Energy Corporation, is conducting business at a significant level today. The companies listed here are those whose work on zinc-bromine is most well known.

Energy Research Corporation (ERC)

ERC licensed Gould's zinc-bromine technology in the late 1970s in the effort to produce a zinc-bromine system for load-leveling applications. This effort, partly funded by EPRI, continued into the late 1980s. In 1993, ERC spun off its battery development group as Evercel, which concentrated on nickel-zinc batteries. As of this writing, Evercel has not maintained a high level of activity in zinc-bromine systems.

Exxon

Exxon Research and Engineering Co. began their zinc-bromine technology development activities in the mid-1970s. In the mid-1980s, Exxon licensed its technology to Johnson Controls, SEA, Toyota, and Meidensha. Exxon has not itself maintained significant research activities in the zinc-bromine area.

Gould

Gould, Inc. developed its zinc-bromine technology from the mid-1970s with support from DOE and EPRI. The Gould design was in most respects similar to the Exxon technology, with circulation of electrolyte through both sides of a bipolar cell stack and storage of bromine as a liquid polybromide complex. Gould licensed this technology to Energy Research Corporation in the early 1980s, but did not maintain significant research or development activities itself.

Johnson Controls, Inc.

Johnson Controls Battery Group, Inc. licensed the Exxon version of zinc-bromine technology in the mid-1980s, and worked extensively to develop and characterize the technology. Of note are the extensive development and characterization programs performed by Johnson Controls and Sandia National Labs in the early 1990s. In 1994, Johnson Controls sold its interest in zinc-bromine technology to ZBB Energy Corporation.

Meidensha

Meidensha licensed the Exxon technology for use in electric utility applications. This reached its highest point in the early 1990s during the Moonlight Project, under which a 1 MW_{ac}, 4 MWh zinc-bromine system was installed in Fukuoka, Japan (see Field Tests section). The company also tested a 30 kWh zinc-bromine system at Miyako Island in conjunction with a solar stirling generator. The company does not appear to have pursued further development since that time.

Powercell Corporation

Now defunct, Powercell Corporation was the result of the purchase of SEA by a Massachusetts company in 1993. The company produced a number of promising demonstration units, and in 1998 introduced a commercial product known as the PowerBlock. This system was rated for a continuous power rating of $100kW_{dc}$, and could deliver 100kWh if discharged at $25kW_{dc}$ [1]. The PowerBlock system was tested in conjunction with two microturbines near the Denver International Airport (see Field Tests section). Powercell Corporation filed for bankruptcy in early 2002. Its technology was purchased by Premium Power Acquisition Corporation (later Premium Power Corporation).

Premium Power Corporation

Premium Power Corporation (PPC) purchased the technology rights for Powercell Corporation's zinc-bromine technology from that company in early 2002. In September 2002, PPC signed an MOU with Composite Power Corporation (CPC) to allow CPC to market the PowerBlock technology. CPC likewise agreed to contribute resources towards the development and manufacturing of the technology. To date, there have been no other significant product announcements from PPC, and it is unclear whether the company intends to release the PowerBlock or any other zinc-bromine product.

Studiengesellschaft für Energiespeicher und Antriebssysteme (SEA)

SEA in Mürzzuschlag, Austria, licensed the Exxon technology for electric vehicle applications. The company installed the technology in several vehicles, notably a Volkswagen bus which was used by the Austrian Postal Service on mountainous routes. SEA later became a part of Powercell Corporation.

Toyota Motor Corporation

Toyota also developed zinc-bromine batteries for vehicles, designing them into a conceptual urban transportation vehicle known as the EV-30 in the mid-1990s. The prototype did not move into a product phase, and does not appear to have been developed further.

ZBB Energy Corporation

ZBB is the major remaining developer of zinc-bromine batteries. The company was formed in Western Australia by a research group from Murdoch University in Perth, Australia. The company subsequently purchased the zinc-bromine technology developed by Exxon and Johnson Controls. ZBB's research and development group continues to reside in Western Australia, but the company has retained the Johnson Controls engineering group and has a new manufacturing facility in Wisconsin, where it has made its principal headquarters.

ZBB has developed a number of demonstration projects, based on a 50 kW-h battery module that is used as a building block for larger systems. Each module is constructed of 3 cell stacks, each with 60 cells. The three stacks are connected in parallel, with common electrolytes. Each module also contains its own electrolyte reservoirs and circulation systems. The modular design allows the ability to produce batteries of the desired voltage, energy, and power rating through the construction of series-parallel arrangements.

ZBB has introduced a 250 kW_{ac}, 500 kW_{ac}-h system in a modified 20 foot by 8-foot container. The container includes a 4-quadrant inverter that provides the additional benefit of reactive power support for distribution lines. The standard size is designed to make transportation and installation as easy as possible. With minor modifications, the 500 kW_{ac}-h system is can be used in several applications.

Transmission and distribution deferral forms an important part of the target market for the system. The system can be used to supply (or absorb) both real power and reactive power in areas where this would allow deferral of transmission and distribution investments. The simple installation and long life of the units makes it easy to transport the device to a new area once T&D investment is made.

The company also considers wind power stabilization an important application for the ZBB system. Traditional wind generation introduces a stability problem to the grid when they form a significant portion of the installed generation capacity. Energy storage can be used to stabilize uneven generation by ensuring a steady output. The ZBB system can be appropriately sized and configured to fit wind farms.

A third target application is what is sometimes called "island power." In these situations, a relatively small grid serves a limited service area. Such a grid is very susceptible to sharp changes in load and unexpected failures of generation. The usual method of maintaining grid reliability without dropping loads in these situations is the activation of large diesel generators. While effective, this can be expensive in terms of fuel and maintenance. As an alternative, energy storage can be used to provide power and stability by following the load while generation is operated efficiently. In island power applications where renewable energy (wind or solar) is used as a significant component of the generation the ZBB system can shift the renewable power from when it is generated to when it is needed, enhancing the economics in these applications.

Field Tests

Extensive zinc-bromine field tests have been conducted in both electric vehicle applications and in utility applications. This section will discuss only utility applications.

Imajuku Energy Storage Test Plant (Fukuoka, Japan)

The Imajuku plant was installed in 1990 at the Imajuku substation by a consortium of companies including the New Energy Industrial Technology Development Organization, the Kyushu Electric Power Company, and Meidensha Corporation. The plant was built as the culmination of a long-term project as part of the Moonlight Project, under the auspices of the Japanese Ministry of International Trade and Industry (MITI).

The Imajuku plant was rated at 1 MW_{ac}, with the capacity to deliver that power for 4 hours (4 MWh_{ac}). The system was used for peak-shaving, discharging directly into the grid during times of peak demand and recharging during low demand periods.

The system was composed of 24 submodules, each sized at 25 kW_{dc}. The system operated between 720 V_{dc} at end of discharge, and 1400 V_{dc} at end of charge. The average discharge current was about 900 A. The DC battery output was supplied to a self-commutated inverter sized for 1000 kVA with a self-cooled output transformer. The system completed over 1300 cycles by 1993 [1].

PowerBlock Near Denver International Airport (Denver, Colorado)

In 1998, Powercell Corporation installed a PowerBlock module near the Denver International Airport. This module was used to store energy developed by two Capstone microturbines, which operated directly from a natural gas well on the premises.

Detroit Edison / Sandia National Labs 400 kWh System (Detroit, Michigan)

In 2001, ZBB Energy installed a transportable 400 kWh zinc-bromine system on a Detroit Edison site in Lum, Michigan in a load management application. This system consisted of 8 50 kWh modules mounted on a truck and configured as two independent strings, allowing a 2 to 10 hour discharge. The system was installed at a substation at the end of a 4.8 kV_{ac} distribution line, to provide relief to an 800 kVA transformer. The transformer normally operated near capacity, and was expected to exceed capacity during peak times during the summer months.

Figure 9-4
ZBB 400 kWh System at Lum, Michigan (Courtesy ZBB Power Engineering)

The system was tested for three months in the summer and autumn of 2001. The testing was considered a success, and led to a general upgrade of the system to support remote web-based dispatch and web-based monitoring. The upgraded system was installed in June 2002 [6].

United Energy 400 kWh System (Melbourne, Australia)

ZBB Energy installed this system in November 2001 for a peak shaving application. Here again, the peak-shaving ability of the device is used to provide relief to a transformer which experiences a high load during peak power times. The system underwent extensive tests on several functionalities of the system, such as storage capacities over various dispatch schedules, peak shaving, power factor control and reactive power compensation, monitoring, availability, and maintenance. The test system continues to operate successfully [6].

PowerLight / NYSERDA Photovoltaic 50 kWh System

ZBB Energy recently paired with PowerLight Corporation, a PV manufacturer, to develop a 50 kWh stand-alone battery system for peak shaving, UPS, and other applications. An initial 50 kW_{dc}, 100 kW-h system is now being installed at an industrial site in New York State. The project is funded by the New York State Energy Research and Development Agency (NYSERDA).

This test site is the first application of ZBB Energy's new "upright" 25 kW_{ac}, 50 kW-h system. The most important feature of this unit is the self-contained power conditioning system (PCS), a 25 kW_{ac}, 30 kVA system developed by SatCon Canada. Both the zinc-bromine battery and the PCS are integrated into a single enclosure suitable for outdoor installation, and capable of supporting HVAC. This system is likely to be used as a building block for future systems [6, 8].

Figure 9-5
ZBB 50 kWh System With Integrated PCS (Courtesy ZBB Energy Corporation)

Technology Development

The most exciting developments in zinc-bromine technology in recent times have been the gradual steps towards the release of commercial products. In the last 5 years, two companies have put forward commercial versions of their products for utility applications, and have field tested these systems in various locations.

Technology development activities by ZBB Energy Corporation, the only major developer of zinc-bromine systems at this time, are focused on improved product design and manufacturing, and product improvements based on results from field testing. These efforts have included improved control algorithms and software. There are also efforts to enhance manufacturing techniques to improve quality and uniformity of product, and to reduce cost.

T&D System Energy Storage System Applications

Select Applications for Zinc-Bromine Battery Systems

This section presents the select applications for which zinc-bromine products are suited and describes the key features of the zinc-bromine systems when configured to meet the select application requirements. Screening economic analyses have shown that present zinc-bromine products are potentially competitive for one of the single function applications as well as one of the combined function applications, which are described in detail in Chapter 3. They are also marginally competitive in another of the single function applications, as well as another of the combined function applications. The following list briefly summarizes all of the Chapter 3 applications, with a reiteration of the key application requirements. Those for which current zinc-bromine products are best suited are enclosed by borders.

Single Function Applications

Application A: Grid Angular Stability (GAS) – mitigation of power oscillations by injection and absorption of real power at periods of 1 to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 20 oscillatory cycles, cumulatively equivalent to a full power discharge (FPD) of 1 second duration and subsequent charge cycle; 1 event per day; 10 events per year. Valued at the cost of alternative solutions.

Application B: Grid Voltage Stability (GVS) – mitigation of degraded voltage by additional reactive power plus injection of real power for durations up to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 1 second FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application C: Grid Frequency Excursion Suppression (GFS) – "prompt" spinning reserve (or load) for mitigating load-generation imbalance. Requires energy storage to discharge real power for durations up to 30 minutes. The reference duty cycle for analysis is standby for infrequent events characterized by 15-minute FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application D: Regulation Control (RC) – system frequency regulation in concert with load following. The reference duty cycle for analysis is characterized by continuous cycles equivalent to 7.5-minute FPD and charge cycle (triangular waveform), 2 cycles per hour deployed with 10 minutes advance notice. Valued at market rates.

Application E: Spinning Reserve (SR) – reserve power for at least 2 hours with 10 minute notice. The reference duty cycle for analysis is standby for infrequent events characterized by 2-hour FPD, 1 event per day, 10 events per year. Valued at market rates.

Application F: Short Duration Power Quality (SPQ) – capability to mitigate voltage sags (e.g., recloser events). The reference duty cycle for analysis is standby for infrequent events characterized by 5 seconds FPD, 1 event per hour, 5 events per day, 100 events per year. Valued at the cost of alternative solutions.

Application G: Long Duration Power Quality (LPQ) – SPQ, plus capability to provide several hours reserve power. The reference duty cycle for analysis is standby for infrequent events characterized by SPQ plus standby for 4 hours FPD, 1 event per year. Valued at the cost of alternative solutions.

Application H: 3-hr Load Shifting (LS3) – shifting 3 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 3-hour FPD, 1 event per day, 60 events per year. Valued at market rates.

Application I: 10-hr Load Shifting (LS10) – shifting 10 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 10-hour FPD, 1 event per day, 250 events per year. Valued at market rates.

Combined Function Applications (In the Order Noted)

Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC)

Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR)

Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR)

Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR)

Application C5: Combined Applications I, D, E (LS10 + RC + SR)

Zinc-Bromine Battery System Compliance With Application Requirements

The ZBB battery module performance parameters discussed above were used to develop approximate sizes and operational parameters for systems meeting the application requirements for the selected applications described in the previous section. Key factors in sizing zinc-bromine systems include:

- Selection of the power rate which characterizes the principle application. ZBB modules deliver power at a maximum rate of 500 kW_{ac}, and operate best at 250 kW_{ac}. Operation at lower rates is possible, but parasitic loads have an impact on the energy capacity and efficiency at lower rates. For applications requiring less than 15 seconds (e.g., SPQ), zinc-bromine systems use a “discontinuous” (pulsed discharge) IGBT-based PCS that accommodates high currents for brief periods.
- State-of-charge management to ensure that the required power and energy are accessible and that the battery is appropriately recharged. Note that the ZBB module is best recharged at a four-hour rate.
- Appropriate maintenance for the application. Applications with very short discharges, such as regulation control, require that stripping cycles be performed on the zinc-bromine module at regular intervals. The intervals between stripping will vary on the frequency and depth-of-

discharge of operation; generally, stripping must be performed more frequently for applications requiring frequent shallow discharges than for those requiring less frequent, deep discharges.

- Cycle and calendar life management to ensure that the system is operated within the service life of equipment, which is especially important for combined function, high cycle applications such as load shifting with regulation control.

Performance aspects of zinc-bromine battery systems for the selected applications are described below and summarized in Table 9-1. The reference power for all applications is 10 MW_{ac}.

- Application A: Grid Angular Instability (GAS) – This application requires that the system continuously detect and mitigate power oscillations. Oscillations require that the system alternately inject and absorb full power, for an equivalent of a 1 sec full power discharge. Twenty-two (22) ZBB 500 kWh modules, capable of discharging at 500 kW_{ac} per module for up to 30 seconds, are equipped with a Type III PCS, sized for a pulse factor of 4 and a minimum discharge voltage of 350 V_{dc} based on discontinuous IGBT converter design. The system will spend virtually its entire life in standby mode, with only occasional deep-cycles to check capacity, and stripping cycles to maintain performance. The resulting standby efficiency is 97.2%. The projected battery life for this application is 20 years.
- Application F: Short Duration Power Quality (SPQ) – This application requires that the system continuously detect and mitigate infrequent PQ events lasting to 2 seconds. Twenty-two (22) ZBB 500 kWh modules, capable of discharging at 500 kW_{ac} per module for up to 30 seconds, are equipped with a Type III PCS, sized for a pulse factor of 4 and a minimum discharge voltage of 350 V_{dc} based on discontinuous IGBT converter design. The system will spend virtually its entire life in standby mode, with only occasional deep-cycles to check capacity, and stripping cycles to maintain performance. The resulting standby efficiency is 97.2%. The projected battery life for this application is 20 years.
- Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR) – This application requires that the system continuously detect and mitigate infrequent SPQ events lasting up to 2 seconds. Twenty-two (22) ZBB 500 kWh modules, capable of discharging at 500 kW_{ac} per module for up to 30 seconds, are equipped with a Type III PCS, sized for a pulse factor of 4 and a minimum discharge voltage of 350 V_{dc} based on discontinuous IGBT converter design. In addition, this system will provide load shifting for 3 hours per day at 2.6 MW_{ac} for 60 days per year, plus RC and SR at 2.6 MW_{ac}. RC is provided for 3 hours per day, 50 days per year, and SR for the remaining 8,189 hours per year. Because of the shallow cycling for RC, the battery will require stripping procedures at regular intervals. The projected battery life for this application is 20 years, as the cycle life (as measured by the cumulative number of hours of operation) exceeds the shelf life.
- Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR) – This application requires that the system continuously detect and mitigate infrequent PQ events and provide reserve power for up to 4 hours, with one event per year. Eighty-five (85) ZBB 500 kW-h modules are equipped with a Type I PCS plus a static switch, sized for a minimum discharge voltage of 350 V_{dc}. In addition, this system will provide load shifting for 3 hours per day at 10 MW_{ac} for 60 days per year, plus RC and SR at 10 MW_{ac}. RC is provided for 5 hours per day, 40 days per year, and SR for the remaining 8,132 hours per year. Because of

the shallow cycling for RC, the battery will require stripping procedures at regular intervals. The projected battery life for this application is 20 years, as the cycle life (as measured by the cumulative number of hours of operation) exceeds the shelf life.

Table 9-1
Zinc-Bromine Battery System Compliance With Application Requirements

	Single Function		Combined Function	
Applications	**App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d**	**App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr**	**App C3: SPQ + LS3 + RC + SR**	**App C4: LPQ + LS3 + RC + SR**
Energy Storage Selection				
Type of Product	ZBB 500 kWh System	ZBB 500 kWh System	ZBB 500 kWh System	ZBB 500 kWh System
Number of Modules	22	22	22	85
Pulse Factor	4.0	4.0	4.0	1.0
Max Charge Voltage	775	560	560	560
Min Discharge Voltage	350	350	350	350
Maximum DOD, %	90%	90%	90%	90%
Cumulative Cycle Fraction	0%	0%	96%	100%
Replacement Interval, yr	20	20	20	20
PCS Selection				
PCS Type (Chapter 5)	III	III	III	I + SST
Duty Cycles				
Grid Support or Power Quality (GS or PQ)				
Power, MW	10	10	10	10
Event Duration, Hr	0.000	0.001	0.001	4
Load Shifting (LS)				
Power, MW			2.6	10
Load Shift Energy, MWh/yr			470	1,817
Load Shift Losses, MWh/yr			181	700
Cycle Life Fraction			60%	60%
Regulation Control (RC)				
Power, MW			2.6	10
Hours per day, hr			3	5
Days per year, days			50	40
RC, MW-Hours/yr			392	2,000
RC Losses, MWh/yr			38	193
Cycle Life Fraction			29%	33%
Spinning Reserve (SR)				
Power, MW			2.6	10
SR, MW-Hours			21,395	81,324
SR Losses, MWh/yr			20	77
Cycle Life Fraction			6.67%	6.64%
Summary System Data				
Standby Hours per Year	8,760	8,760	8,209	8,152
System Net Efficiency, %	97.2%	97.2%	97.1%	94.1%
Energy Storage Standby Efficiency, %	99.2%	99.2%	99.2%	97.0%
PCS Standby Efficiency, %	98.0%	98.0%	98.1%	98.1%
System Footprint, MW/sqft (MW/m^2)	0.0021 (0.0225)	0.0021 (0.0225)	0.0021 (0.0225)	0.0007 (0.0073)
Energy Storage Footprint, MW/sqft (MW/m^2)	0.0029 (0.0308)	0.0029 (0.0308)	0.0029 (0.0308)	0.0007 (0.008)

Benefit and Cost Analyses

Zinc-Bromine Battery Pricing and Integrated System Costs

ZBB Energy Corporation has developed pilot-scale commercialization of the 500 kWh system, including pilot-scale manufacturing facilities, firm prices, commercial warranties, and full service options. Market introduction is underway through the development of several high-value demonstration projects. The nominal unit price for utility-scale applications in North America is about $163K per module, depending on the number of modules. For the Handbook's specified deployment date of 2006 and rating of 10 MW, nominal unit prices are based on 2003 prices.

ZBB Zinc-Bromine Systems	2006 Prices, K$	Mature Prices, K$
Price per kWh	$325	$250
Price per module (250kW, 500kWh)	$162.5K	$125

In addition to the ZBB battery modules, the related scope of supply includes the battery control and management system, DC circuit breakers (for PQ modules), exterior enclosures, environmental controls, and technical support for system integration, installation, and startup.

The cost of integrated zinc-bromine systems is obtained by combining the cost of the zinc-bromine battery scope of supply with the appropriate PCS and BOP costs as described in Chapter 5. The PCS and BOP costs shown in Table 9-2 are based on the methodology described in Chapter 5. Zinc-bromine systems for short duration discharge applications (e.g., SPQ) use Type III "discontinuous" IGBT-based PCS which accommodate high currents for brief periods at reduced cost compared to continuous ratings as described in Section 5.3. Since the cost of exterior enclosures is included in the zinc-bromine battery scope of supply, the cost of exterior space and foundations for zinc-bromine batteries is included at $20/sqft.

Table 9-2
Capital and Operating Costs for Zinc-Bromine Battery Systems

Applications	Single Function		Combined Function	
	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr	App C3: SPQ + LS3 + RC + SR	App C4: LPQ + LS3 + RC + SR
Battery Capacity, MWh_{ac}	0.003	0.006	8	40
PCS Initial Cost, $/kW	173	173	173	476
BOP Initial Cost, $/kW	100	100	100	100
Battery Initial Cost $/kW	366	366	366	1,413
Battery Initial Cost $/kWh	1,320,000	660,000	467	353
Total Capital Cost, M$	6.4	6.4	6.4	19.9
O&M Cost – Fixed, $/kW-year	12.8	25.8	30.0	39.8
O&M Cost– Variable, $/kW-year	9.4	9.4	8.8	16.1
NPV Disposal Cost, $/kW	1.8	1.8	1.8	7.0

Note: The total initial cost may calculated in two ways:
1. By mutiplying the sum of PCS, BOP and Battery initial costs expressed in $/kW by the reference power,
2. OR by mutiplying the sum of PCS and BOP expressed in $/kW by the reference power and then adding the product of Battery Initial cost expressed in $/kWh and the Battery Capacity

Fixed O&M costs for the PCS are based on $2/kW as required by provisions in Chapter 5, plus zinc-bromine battery maintenance in accordance with the vendor. ZBB's recommended maintenance program consists of continuous remote monitoring, stripping cycles as required by the cycling regime, and detailed inspections conducted at biannual intervals. Stripping cycles help to ensure that proper operation and long life for the system, and are required at regular intervals for those regimes which involve a large number of relatively shallow cycles. These cycles are conducted separately on individual modules, so that there is no reason to take the system off-line. The biannual detailed inspections include the following steps:

- Physical inspection for abnormal conditions of connecting cables and exterior enclosure
- Inspection of pumps and other moving parts

- Inspecting for unusual vibrations, noise or odors
- Full-discharge and recharge, with collection and analysis of battery voltage and current data

The maintenance program offered by ZBB, which includes biannual inspections, costs $5000 annually. In addition, the levelized annual labor associated with stripping cycles (for those applications which require them) is estimated at 18 hours per module. Fixed O&M costs are based on labor costs of $50 per hour (or $900 per module per year). In addition, an annual allowance for property taxes and insurance, based on 2% of the total initial capital costs, is included in the fixed O&M costs.

Variable O&M costs for the system include the cost of electrical losses to maintain the PCS and the battery during hot standby intervals. An allowance for zinc-bromine battery disposal is included at $3,500 per module at the end of battery life, including the cost of shipping, recycling useable material, and disposition of zinc and bromine residuals.

Lifecycle Benefit and Cost Analysis for Zinc-Bromine Battery Systems

Further insight to the value of energy storage can be gained through lifecycle cost analyses using a net present value (NPV) methodology and comparison with alternatives. For the convenience of the reader, the financial parameters and electric rate structure set forth in Chapters 4 and 5 and used in the analyses are summarized in Table 9-3 and Table 9-4.

Table 9-3
Financial Parameters

Dollar Value	2003
System Startup	June 2006
Project Life, years	20
Discount Rate (before tax), %	7.5
Property Taxes & Insurance, %/year	2
Fixed Charge Rate, %/year	9.81

Table 9-4
Electric Rates

Load Shifting On Peak Period	3	10
Number Cycles per year	60	250
On-Peak Energy, $/MWh	120	80
Off-Peak Energy, $/MWh	20	
Yearly Average Energy Charge, $/MWh	38	
Regulation Control, $MW-Hour (power), $/MWh	15	
Spinning Reserve, $MW-Hour (power), $/MWh	5	
Transmission Demand Charge, $/kW-mo	5	

The results of lifecycle cost benefit analyses of select zinc-bromine battery applications are summarized in Table 9-5 and discussed below. The bases and methodology used in valuing energy storage applications is described in detail in Chapter 4. The details of the cost benefit analysis for each application are discussed below.

Table 9-5
Summary of Benefit and Cost Analyses of Zinc-Bromine Battery Systems

Applications	Single Function		Combined Function	
	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr	App C3: SPQ + LS3 + RC + SR	App C4: LPQ + LS3 + RC + SR
Alt Solution Value, $/kW	750	1,000	1,500	2,000
Initial Installed Cost, M$	6.38	6.38	6.38	19.89
Total Costs, M$	(10.4)	(10.0)	(10.4)	(31.8)
Total Benefits, M$	7.50	10.0	16.5	25.9
Benefit to Cost Ratio	0.72	1.00	1.60	0.81
NPV, M$	(2.9)	0.0	6.2	(5.9)
Battery Module	ZBB 500 kWh System	ZBB 500 kWh System	ZBB 500 kWh System	ZBB 500 kWh System
Number of Modules	22	22	22	85
Battery 2006 Price, K$/module	163	163	163	163
Price for NPV=0, K$/module	52	163	395	104

- Application A: Grid Angular Stability (GAS) – This application was evaluated on the assumption that an alternative system capable of mitigating GAS events can be obtained for capitalized acquisition and operating costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 9-5, this application yields a negative NPV of $(2.9) million for an initial investment of $6.4 million. As a measure of the sensitivity of NPV with respect to alternative system costs, Figure 9-6 illustrates the change in NPV over a range of $500 to $1000/kW, and shows that zinc-bromine systems are marginally viable over this range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the nickel-cadmium system were reduced from $163 to $52 thousand per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $750/kW.

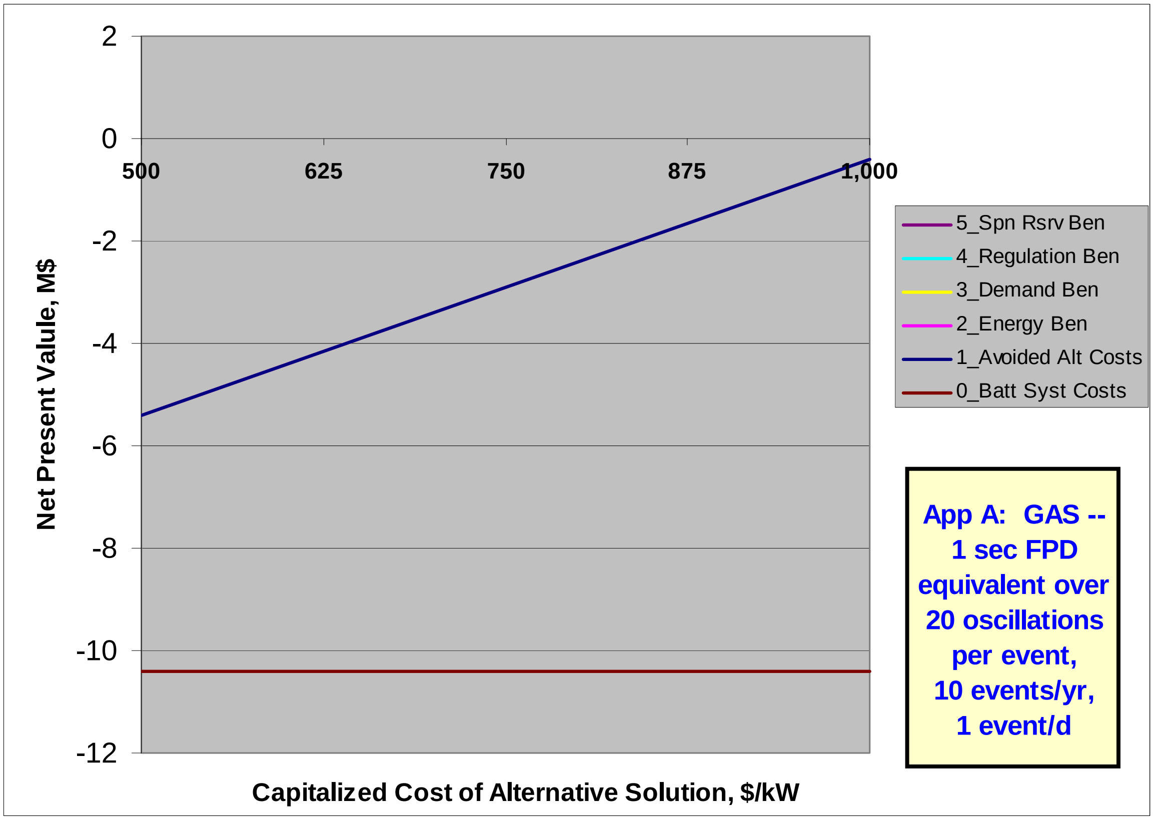

Figure 9-6
Application A: Zinc-Bromine System NPV vs Cost of Alternative System

- Application F: Short Duration Power Quality (SPQ) – This application was evaluated on the assumption that an alternative solution capable of mitigating SPQ events can be obtained for net capitalized costs of about $1000/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 9-5, this application yields a NPV of about $0 for an initial investment of about $6.4 million on this basis – that is, costs and benefits are roughly equal for this application. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 9-7 illustrates the change in NPV over a range of $500 to $1500/kW and shows that zinc-bromine systems will compete favorably against alternative solutions with net capitalized costs in excess of $1000/kW.

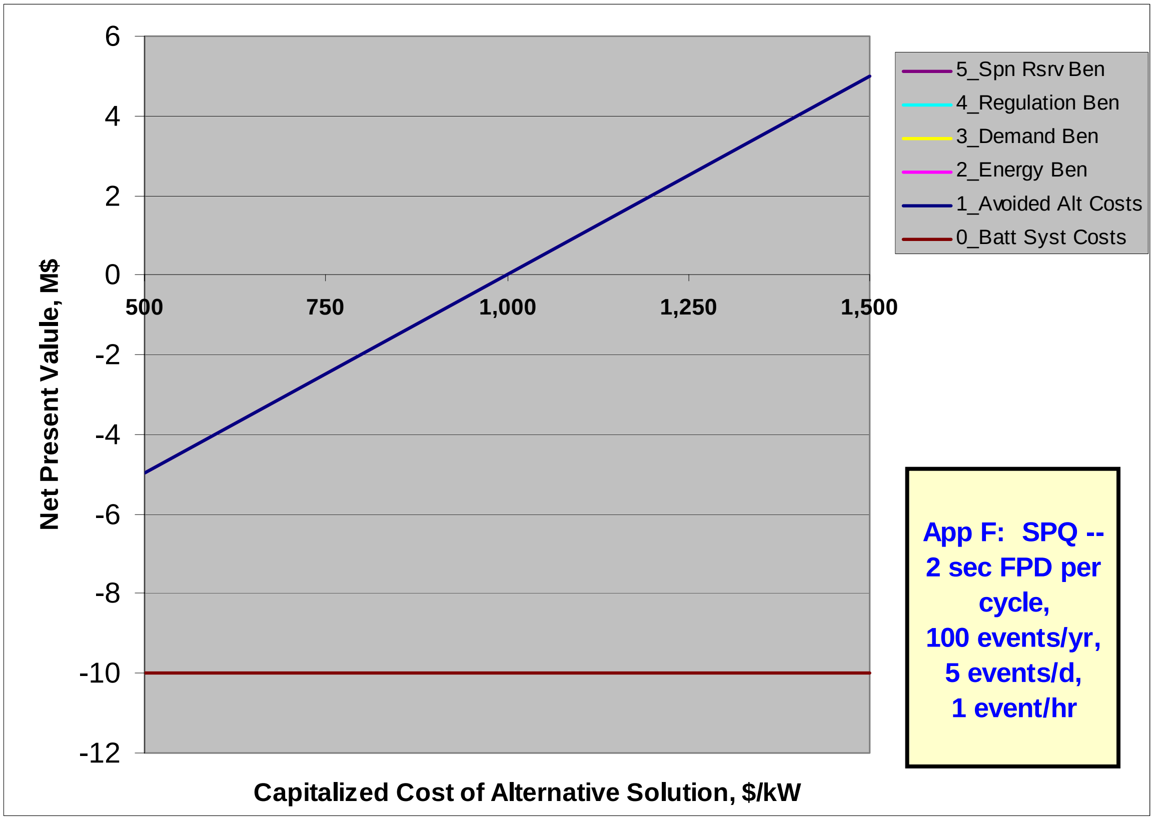

Figure 9-7
Application F: Zinc-Bromine System NPV vs Cost of Alternative Solution

- Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating SPQ events, plus avoided LS3 related upgrade costs, can be obtained for net capitalized costs of about $1500/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 3-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Table 9-5, this application yields a NPV of $6.2 million for an initial investment of about $6.4 million on this basis. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 9-8 illustrates the change in NPV over a range of $1000 to $2000/kW, as well as the incremental value of load shifting (both energy and demand), regulation control and spinning reserve functions. With these value elements, zinc-bromine systems will compete very favorably against alternative solutions over this range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of zinc-bromine modules were increased from $163 to $395 thousand per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $1500/kW.

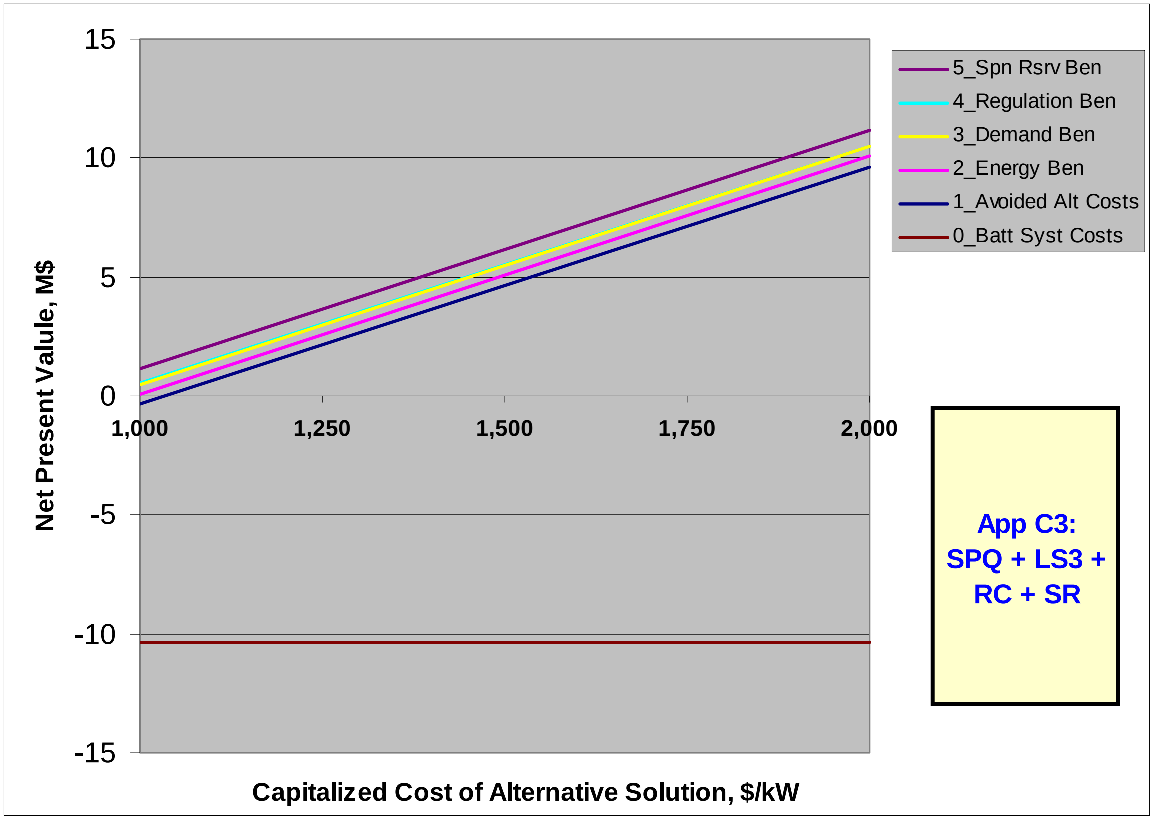

Figure 9-8
Application C3: Zinc-Bromine System NPV vs Cost of Alternative Solution

- Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating LPQ events, plus avoided LS3 related upgrade costs, can be obtained for net capitalized costs of about $2000/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 3-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Table 9-5, this application yields a negative NPV of $(5.9) million for an initial investment of about $19.9 million on this basis. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 9-9 illustrates the change in NPV over a range of $1500 to $2500/kW, as well as the incremental value of load shifting (both energy and demand), regulation control and spinning reserve functions. With these value elements, this zinc-bromine system will compete marginally against alternative solutions at the high end of this range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of ZBB modules were reduced from $163 to $104 thousand per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $2000/kW.

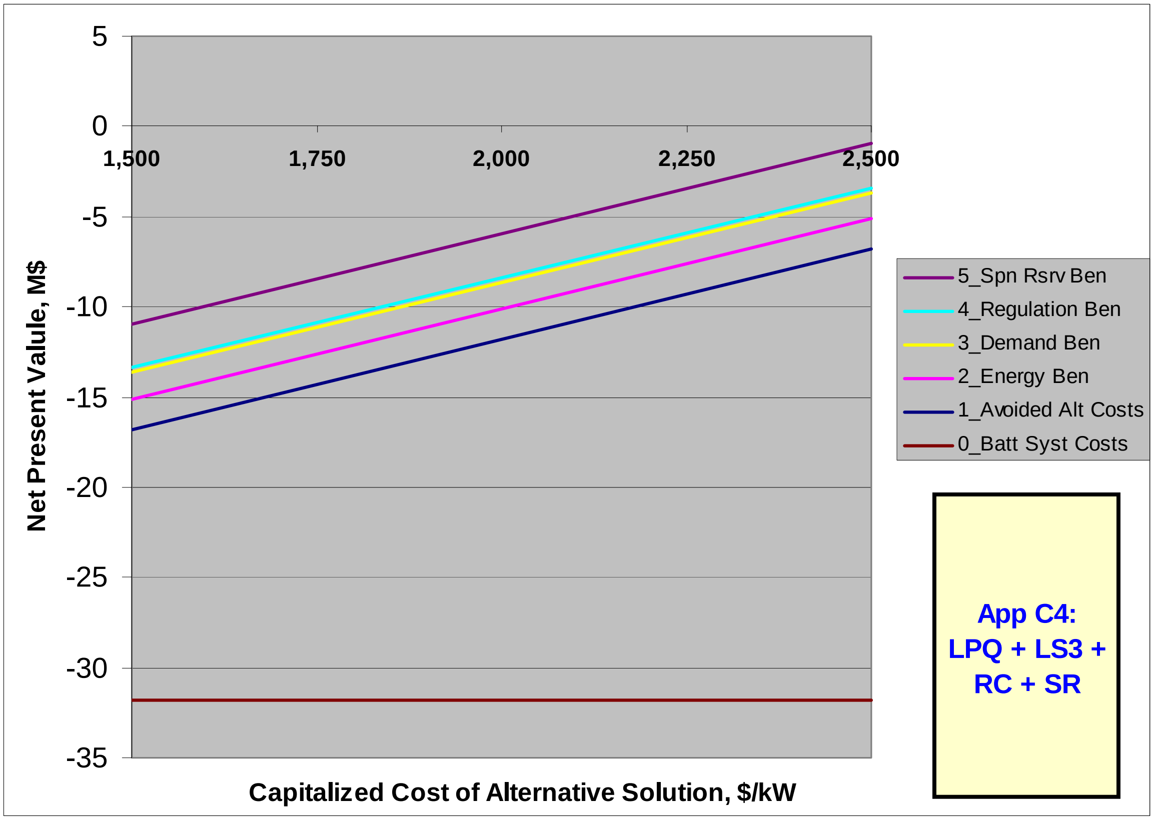

Figure 9-9
Application C4: Zinc-Bromine System NPV vs Cost of Alternative Solution

Interpreting Results from Benefit-Cost Analyses

In general, zinc-bromine battery systems are expected to be competitive for some single function applications and attractive investments for at least one combined function applications described above. They are especially attractive in SPQ applications which allow the use of "discontinuous" IGBT-based PCS.

The reader is reminded that the foregoing analyses are intended as a guide to the initial consideration of energy storage options, and that these analyses are based on representative electric rates and costs for alternative solutions as described in Chapter 4. The assumptions used herein should be reviewed in light of project specific applications, alternative solutions, electric rates and financial parameters.

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10
VANADIUM REDOX BATTERIES

Introduction

The Vanadium Redox Battery (VRB) is a flowing-electrolyte battery (or "flow battery") that stores chemical energy in external electrolyte tanks sized in accordance with application requirements. Aqueous liquid electrolyte is pumped from storage tanks through reaction stacks where chemical energy is converted to electrical energy (discharge) or electrical energy is converted to chemical energy (charge).

Early work on various redox batteries was undertaken by NASA in the 1970s and later by the Electro-Technical Laboratory (ETL) in Japan. In 1984, this foundation was applied to the VRB at the University of New South Wales (UNSW) in Sydney, Australia. Their work focused on the vanadium / vanadium redox couple, electrolyte stability at high concentrations, and production of electrolyte from raw materials. Several proof-of-concept systems were built by UNSW and others including a battery to store electricity produced by solar photovoltaic panels (Thai Gypsum Products, Thailand), an emergency back-up system for submarines (Australian Department of Defense), a battery for an electric golf car, and a 200 kW_{ac} / 800 kWh load-leveling battery (Mitsubishi Chemicals/Kashima-Kita Electric Power Corporation, Japan).

In 1998, intellectual property rights to the technology were sold to Pinnacle VRB, Ltd. (Sydney, Australia). Pinnacle VRB was subsequently acquired in 2001 by VRB Power Systems, Inc., of Vancouver, Canada. Sumitomo Electric Industries (SEI) of Osaka, Japan acquired the ETL technology and, under license to Pinnacle VRB, further developed the technology by designing cell stacks and complete integrated systems.

In addition to the UNSW/SEI development efforts, several VRB-related technologies have been under development since 1995 by Squirrel Holdings, Ltd (Thailand). These include a series-flow battery, electrolyte production, and a vanadium-based fuel cell that is fueled by locally-grown agricultural crops.

Description

As illustrated in Figure 10-1, the VRB cell is based upon electron transfer between different ionic forms of vanadium. 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+}.

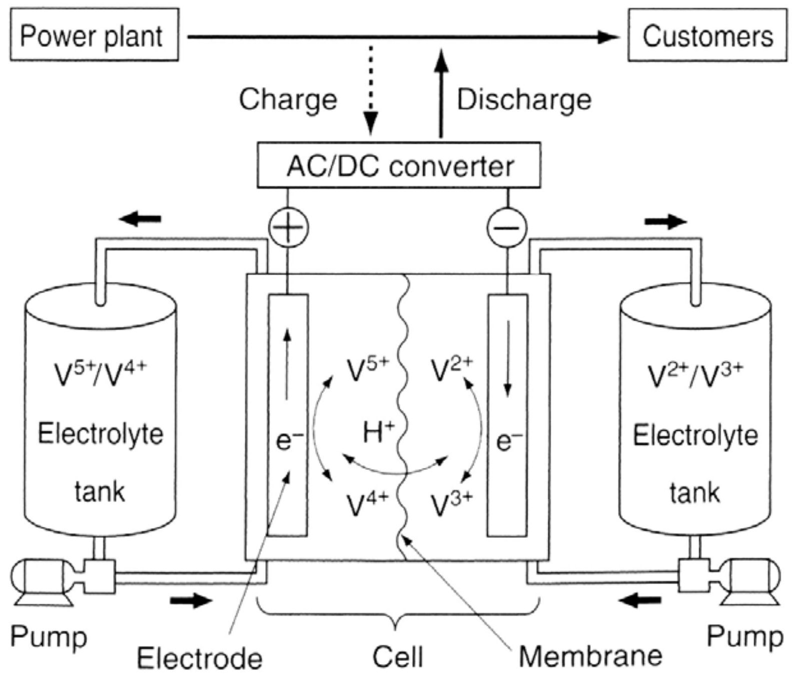

Figure 10-1
Principles of VRB (Courtesy SEI)

Overall, the reactions that take place at the electrodes are given by the following equations:

Positive electrode: $V^{4+} \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} V^{5+} + e^-$ **Eq. 10-1**

Negative electrode: $V^{3+} \underset{\text{Charge}}{\overset{\text{Discharge}}{\rightleftarrows}} V^{2+} + e^-$ **Eq. 10-2**

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. It is stored in external tanks and pumped as needed to the cells.

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.

Cells have a nominal voltage of about 1.2 V_{dc} as defined by the electrochemical properties. To achieve useful voltages (such as those used as inputs to a DC-to-AC power conversion system), cells are combined ("stacked") electrically in series. In most constructions, "cell stacks" are fed by distributing electrolyte through a manifold to each cell. Figure 10-2 illustrates a typical parallel-feed cell-stack design that combines electrodes, membranes, and frames.

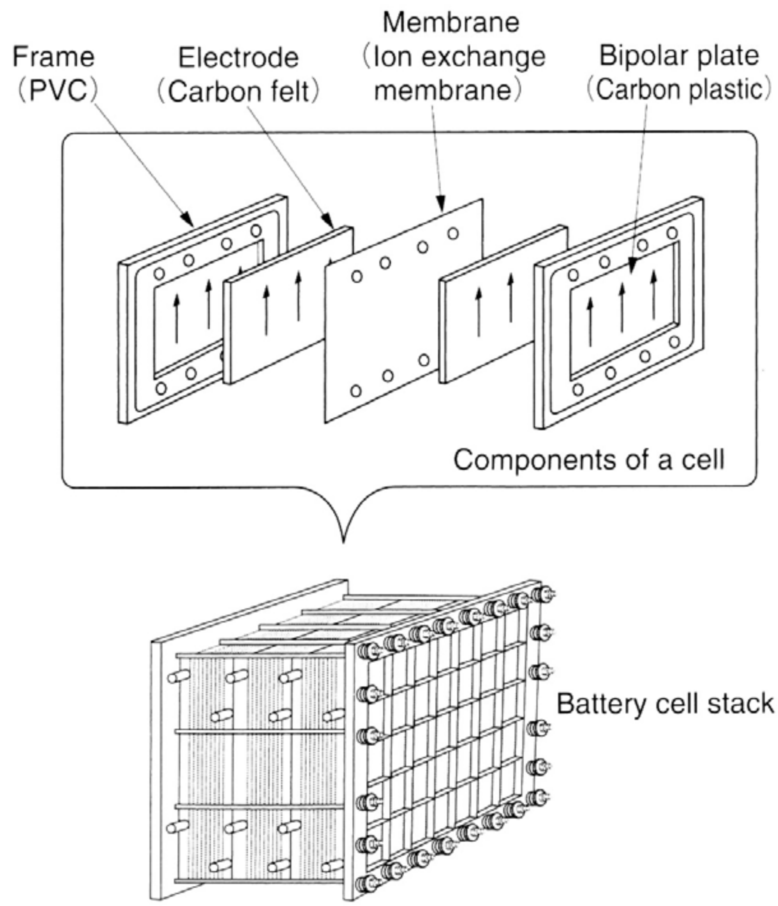

Figure 10-2
Construction of a VRB Cell Stack (Courtesy SEI)

Technology Attributes

Capacity

The capacity of a battery energy storage system (BESS) is measured in both maximum power level (kW) and energy storage capability (kWh). In the case of the VRB, these two system ratings are independent of each other. In principle, the battery stack and PCS capabilities determine the kW rating, while the electrolyte concentration and storage tank dimensions determine the amount of energy that can be stored.

For a given power level, the incremental cost of energy storage is based primarily upon the cost of additional electrolyte storage. The VRB technology favors applications having a high kWh/kW ratio, i.e., applications requiring several hours of storage. Most VRB systems fielded to date for commercial based applications are capable of discharging at maximum design power for a period of 4 to 10 hours.

Space Requirements

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.

For example, in one project, the tanks and stacks were located on separate floors, increasing the height requirement, but decreasing the footprint. In another project, tanks were made from rubber bladders that could be folded and passed through confined passageways and then expanded and installed in an unused underground office basement area.

Maintenance Requirements

Without extended field experience, the system maintenance requirements are not well established. However, there are only two moving parts in a typical system – pumps on the positive and negative sides. Thus, maintenance costs are relatively low. Further, the VRB system operates at atmospheric pressure and the temperature never exceeds 40 degrees C. Primary maintenance items are annual inspections and replacement of pump bearings and impeller seals at intervals of about every five years. As necessary, smaller parts, such as electronic boards, sensors, relays, and fuses are replaced.

Life

The critical system component is the cell stack, which can degrade in performance over time and require replacement or refurbishment. While over 14,000 cycles have been reported, VRB Power recommends replacement of cell stacks after about 10 years [1]. 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

Several losses must be accounted for in characterizing the VRB performance:

- **Transformer losses:** Most utility scale and industrial PCSs are designed with outputs around 480 V_{ac}. To connect to utility distribution voltages, a transformer must be installed resulting in losses of a few percent. Even for non-utility systems, isolation transformers are installed to prevent DC injection into the AC grid.
- **PCS losses:** Whether charging or discharging, power flow through the PCS is subject to losses related to voltage drops across the switching devices. PCS throughput efficiency depends somewhat on load and PCS design, but is typically about 95%.
- **Battery DC losses:** The energy to charge the battery is typically 20% greater than the energy delivered during discharge for a full power rated discharge interval. Internal battery losses include voltaic losses such as ionic flow resistance and coulombic losses such as cell-

to-cell shunt currents (stray ionic flow through the stack manifold). Actual DC losses depend on rate of charge and discharge (the system is slightly more efficient at lower rates).

- **Pumping losses:** Pumping power is an auxiliary load that is drawn whenever electrolyte must be supplied to the stacks, i.e., during charge and discharge. In some applications such as backup power, it is possible to charge the battery, then turn the pumps off for long periods of time. The actual efficiency penalty for pumping depends upon the frequency of cycling and the pump design.

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 75% over the life of the system.

Response Time

The battery is capable of transitioning from zero output to full output within a few milliseconds – virtually instantaneously – provided the stacks are primed with reactants. However, the controls and communications equipment (sensing the load requirements and signaling the PCS to take action) and the PCS typically respond within 10 to 20 milliseconds.

For short-term voltage sag protection, there is sufficient stored electrolyte in the stacks to respond without the pumps running. Five times rated output is available at a state-of-charge (SOC) of 50 to 80% and at least 2.5 times at a SOC as low as 10%. Afterwards, with the pumps idling, they are on-line within seconds to sustain the protection. 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.

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, which is 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.

As with all storage technologies, every charge/discharge cycle results in some loss of energy due to system inefficiencies. For typical grid-connected applications, this means that from a global perspective, there may be increased air emissions associated with the generation of this lost energy. Of course, for renewable energy applications, there are no air emissions considerations, and in some applications, the VRB serves to increase the utilization of renewable sources.

DC Electrical Characteristics

In most VRB systems, the DC bus is connected to the cell stack terminals. The DC voltage is determined by the cell count, and is typically 100 V_{dc} or more. One and 5 kW cell stack assemblies are also available for solar and telecom applications through VRB Power Systems Inc. When power requirements exceed the current ratings of a single stack, multiple stacks are connected in parallel. However, other configurations are possible. Stacks can be placed in series to boost DC voltage, but this requires separate electrolyte hydraulic plumbing and storage to minimize ion flow losses ("shunt currents") that increase with voltage. Cellenium is developing an unconventional power conversion technology in which individual cells are tapped and switched, providing near-sinusoidal outputs with incremental voltage steps equal to the cell voltage.

It is likely that future VRB systems will be manufactured in several standard AC configurations to eliminate project-specific engineering costs. Today's systems, however, include custom-specified PCSs and project specific DC designs.

As the battery is charged and discharged, the DC bus varies in voltage. The open circuit voltage varies with the battery state-of-charge, and charging or discharging produces a corresponding increase or decrease in bus voltage. The PCS must be designed to handle the full voltage "window".

As charged electrolyte is stored in separate anolyte and catholyte tanks, no self-discharge occurs during extended periods of downtime. This would be advantageous in applications such as spinning reserve that require availability of stored energy, but do not require instantaneous power on demand. Under these conditions, the pumps would be powered down, causing the stacks to drain back into the tanks, and the battery would retain its full charge without incurring ongoing parasitic pump losses. It could be restored to full power in a matter of minutes by restarting the pumps and flooding the stacks. Alternatively, the pumps could be in an idling state at a loss of about 500W per pump, and charged electrolyte would be available all the time for prompt spinning reserve.

While it would be possible to design the hydraulic system to retain active electrolyte in the stacks when the pumps were off, the battery would self-discharge over a period of a few days, depending upon the stack (and associated manifold) volume, the number of cells (stack voltage), and the concentration of electrolyte. Furthermore, the energy storage capacity would be negligible.

The battery is typically connected to the DC bus that feeds the PCS. In this configuration, the PCS would be designed to operate within the voltage window of the cell stack or series of cell stacks. An alternative configuration is to insert a DC/DC chopper circuit between the battery and the DC bus so that the PCS operates at a voltage independent of the battery state-of-charge.

AC Electrical Interconnection

Most VRB applications require a PCS to convert the DC energy of the battery into usable AC electric power. Modern power conversion technology provides for bi-directional power flow, so the same equipment can be used for both charging and discharging the battery.

A wide range of PCS configuration options are possible. These include off-grid systems, such as would be required for remote renewable energy applications that provide constant AC voltages to the load. Grid-connected systems, such as would be used for utility and industrial applications, are connected at a fixed voltage and vary current to and from the grid.

The systems are designed to meet all utility interconnection requirements, such as

- Over/under voltage protection
- Overcurrent protection
- Over/under frequency protection
- Manual disconnect switches

These requirements vary by utility, and they typically vary by power rating or interconnection voltage. The approach to common PCS applications and costs for this Handbook is addressed in Chapter 5.

Status of Vanadium Redox Batteries

Commercial Licensing

The largest VRB suppliers are Sumitomo Electric Industries (SEI) of Japan and VRB Power System, Inc.[11] of Canada. VRB Power System, Inc. is also the controlling shareholder of Pinnacle VRB, who has licensed SEI to use the technology. These companies each have non-exclusive rights to manufacture and market their products anywhere in the world[12]. In turn, they pay either royalties or site licenses to Pinnacle, depending upon the project location.

Key patents held by Pinnacle relate to the use of vanadium in each of the two half-cell reactions, the construction of cells such as the bipolar electrodes, and the electrolyte formulae that allows for high concentrations of vanadium sulfide in solution without precipitating into solid. SEI and VRB Power each hold other VRB-related patents that are independent of the Pinnacle patents.

[11] Formerly Vanteck Technology Corporation

[12] The licensing agreements call for certain restrictions, and they differentiate between applications as to whether royalties or license fees apply. However, in practice, these terms are not expected to materially impact the commercialization efforts of either supplier.

SEI and VRB Power are both competitors and potential supply channels to each others. SEI has developed important stack manufacturing expertise and capacity, however, alternative suppliers are under development. VRB Power has a strategic alliance with Highveld Steel and Vanadium Corporation (South Africa), producer of 38% of the world's vanadium supply.

Cellenium (Thailand) is not a licensee of Pinnacle, and it is unclear whether they plan to (1) enter into a license agreement, (2) to delay commercialization until after the patents expire, or (3) to contest the legality of the patents. Cellenium has exclusive rights to a number of international patents as the sole licensee of Squirrel Holdings, Ltd.

Sumitomo Electric Industries, Ltd.

SEI is a major supplier to the electric power industry with 8,500 employees and nearly $7B in annual sales. Since 1985, SEI has researched and developed the VRB system, and has fielded a number of demonstration systems in Japan.

SEI markets its VRB products worldwide and has commercial sales of MW-scale systems in Japan. In North America, SEI's products are marketed exclusively by Reliable Power Inc. (Arlington, Virginia). SEI intends to establish a VRB manufacturing company in North America as the demand for VRB systems increases.

Various demonstration and commercial projects serve to establish the viability of the technology in a variety of applications and operating modes. While incremental improvements to the technology are anticipated, the basic research is complete, and efforts are primarily focused on product development and manufacturing. Table 10-1 identifies the current SEI commercial based projects in Japan [2]. In addition, there are several small R&D based projects at laboratories, including a unit in Italy. Recently, SEI has initiated the development of a 4 MW_{ac} /6 MWh wind farm based project in Japan with J Power (part of EPDC).

Multiple cell stack designs have been and will be manufactured by SEI to meet a variety of application requirements. One such design, provided to Vantech (now VRB Power) for the Stellenbosch project, incorporated 100 cells in series, is rated at 42 kW continuous (130 kW peak), has dimensions of 1.2m (L) x 0.9m (W) x 1.1m (H), and a weight of 1,400 kg. Other projects in Japan incorporated stacks with ratings of 20 kW and 50 kW.

Table 10-1
SEI Project Experience

Location	Application	Ratings	Operation
Utility Company	Peak shaving	450 kW_{ac} / 2 hr	Mar 1995
Office Building	Peak shaving	100 kW_{ac} / 8hr	Feb 2000
Utility Company	Peak shaving	200 kW_{ac} / 8 hrs	Jun 2000
Institute of Applied Energy	Stabilization of wind turbine output	170 kW_{ac} / 6hr	Mar 2001
Golf Course	PV hybrid	30kW_{dc} / 8hr	Apr 2001
High Tec Factory.	UPS / Peak shaving	3 MW / 1.5 sec plus 1.5 MW / 1 hr	Apr 2001
Utility Company	Peak shaving	250 kW_{ac} / 2 hr	May 2001
University	Peak shaving	500 kW_{ac} / 10hr	Jul 200l
Utility Company	Peak shaving	100 kW_{ac} / 1 hr	Mar 2003
Office Building	UPS / Peak shaving	120 kW_{ac} / 8 hr	Jun 2003
High Tec Factory	UPS / Peak shaving	300 kW_{ac} / 4 hr	Aug 2003

VRB Power Systems

VRB Power is a small C$100 million technology development company based in Vancouver, BC. VRB Power is listed on the TSX Venture Exchange ("VRB"), the OTC Pink Sheets ("VRBPF") and on the Frankfurt Exchange ("VNK"). The company has invested several million dollars on the advancement of VRB technology, with most of the effort in systems design rather than research.

The company has strategic relationships with Highveld Steel and Vanadium Corporation (South Africa) for vanadium material supply, SEI for cell stacks (Figure 10-3) and TSI-Eskom (South Africa) for power electronics. VRB Power is also developing small systems (1 to 5 kW), and a commercial product is projected by July 2004.

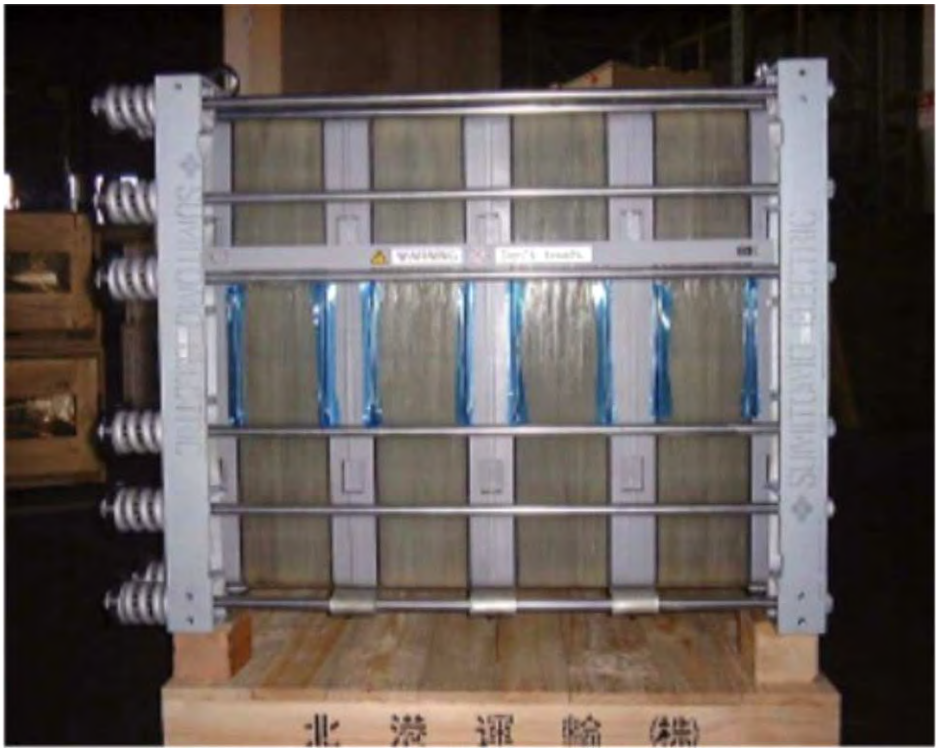

Figure 10-3
SEI Cell Stack (Courtesy VRB Power)

To prove the system design and reliability of a large-scale system in the field, VRB Power 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 V_{dc}) arranged in series with two hydraulic systems. Figure 10-4 shows the stacks and tanks from this project. Building upon the success of this project, the company has installed a 250 kW_{ac} and 2 MWh system in Moab Utah for PacifiCorp and through its subsidiary Pinnacle VRB, a 200 kW_{ac} and 800 kWh system at the King Island wind power plant in Australia. The latter system will be used to stabilize wind power fluctuations and maximize energy production.

Figure 10-4
Typical VRB Stacks and Tanks (Courtesy VRB Power)

Cellenium Company, Ltd.

Cellennium was originally involved in the development of the VRB under the company name Thai Gypsum that, in 1995, demonstrated an early battery in a solar photovoltaic application. In its current corporate form, the company is not a licensee of the Pinnacle technology, and it is unique among the developers in its approach to the marketplace. The company is pursuing three separate vanadium technologies:

- A 1 kW battery with a unique “series” flow design and biomass application;
- A technique for dissolving vanadium pentoxide in acid to produce electrolyte; and
- A power conversion technology that uses the VRB stack design.

Cellenium is headquartered in Thailand with subsidiaries in US and Europe. Research is conducted by a variety of organizations in the U.S. (Washington and Arizona), Sweden, Italy, Switzerland, and Thailand. Several million dollars of private investment has funded its development activities, and an additional $5-10M will be required for commercialization over the next two years.

Unlike the Pinnacle technology, Cellenium uses a unique series flow through its stacks as illustrated in Figure 10-5. This design virtually eliminates shunt currents and ensures that each cell has the same flow rate, however each cell operates at a different voltage, unlike parallel flow designs.

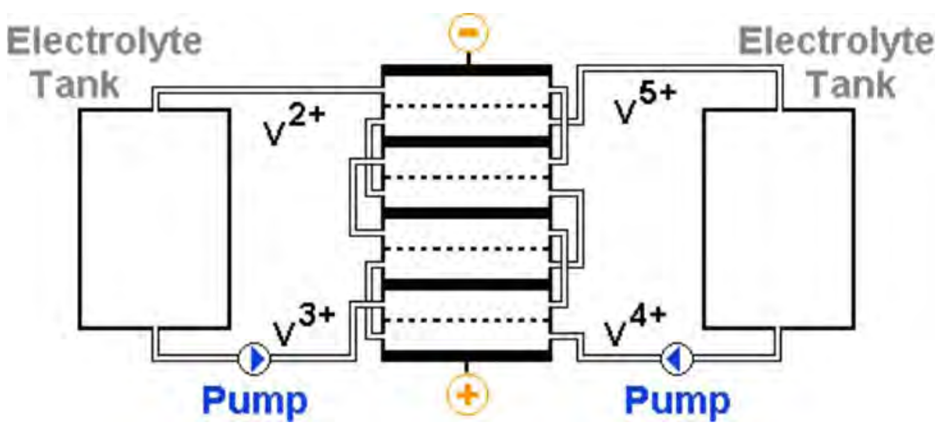

Figure 10-5
Cellenium Series Flow Design

Cellenium is developing other non-storage vanadium technologies, including a vanadium sulfate fuel cell technology that is capable of converting locally-produced sugar crops into electricity. Their market strategy focuses primarily on this application rather than the storage battery.

While the Cellenium VRB is capable of connecting to a conventional PCS, the company is developing a unique “inductionless” power conversion technology that would replace the conventional PCS. By tapping each individual cell within the stack, an AC waveform can be produced by switching individual cells. The “AC terminals” on the battery can produce a relatively smooth waveform with a peak of 170 V_{dc} and a step resolution of 1.3 V_{dc} (the cell voltage). The system can be used as a frequency converter or a standard AC/DC converter.

Pre-commercial 1 kW Cellenium VRB prototypes include systems used for (1) solar grid connected applications, (2) solar stand alone applications, and (3) load leveling applications.

Status of VRB Technology

Table 10-2 summarizes the current commercial status of the Vanadium Redox Battery.

Table 10-2
Current Commercial Status of VRB Technology

Technology/Company	SEI	VRB Power	Cellenium
Status	Early-commercial	Early-commercial	Developmental
Funding Organization	Publicly traded company	Publicly traded company	Private funding in Thailand
Major Demonstrations (all ratings are AC)	Office Building, 100 kW / 8hr (Feb 2000) Utility Company 200 kW / 8 hr (2000) Institute of Applied Energy, 170kW / 6h (Mar 2001) High Tec Factory, 3 MW / 1.5 sec plus 1.5 MW / 1 hr (Apr 2001) Utility Company, 250 kW / 2 hr (2001) University, 500 kW / 10 hr (Jul 200l)	Univ. of Stellenbosch, 250 kW / 2 hr (Aug 2001) PacifiCorp, 250 kW / 8 hr (Late 2003) King Island, 200 kW / 4 hr (Fall 2003)	Three units, each 1 kW (Planned)

Table 10-2 (cont.)
Current Commercial Status of VRB Technology

Technology/Company	SEI	VRB Power	Cellenium
Lessons Learned	Construction and utility interconnection experience Experience with multiple applications (wind, PV, peak shaving, power quality) Developed capabilities to scale up to large power levels		Proven series flow concept
Development Trends/Plans	Market expansion worldwide Larger, scaled-up systems Standardized product lines		Vanadium sulfate fuel cell “Inductionless” power conversion technology
Issues	Systems not safety or performance certified (e.g., UL listing) Long term cycling experience lacking Relatively large footprint Little ongoing maintenance experience		IP rights uncertain Funding for commercial development

T&D System Energy Storage System Applications

Select Applications for VRB Battery Systems

This section presents the select applications for which VRB batteries are suited and describes the key features of VRB systems configured to meet requirements of select applications. Screening economic analyses have shown that VRB battery systems are potentially competitive for one single function application as well as four of the combined function applications, which are described in detail in Chapter 3. The following list briefly summarizes all of the Chapter 3 applications, with a reiteration of the key application requirements. Those for which VRB batteries are best suited are enclosed with borders

Single Function Applications

Application A: Grid Angular Stability (GAS) – mitigation of power oscillations by injection and absorption of real power at periods of 1 to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 20 oscillatory cycles, cumulatively equivalent to a full power discharge (FPD) of 1-second duration., 1 event per day; 10 events per year. Valued at the cost of alternative solutions.

Application B: Grid Voltage Stability (GVS) – mitigation of degraded voltage by additional reactive power plus injection of real power for durations up to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 1 second FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application C: Grid Frequency Excursion Suppression (GFS) – "prompt" spinning reserve (or load) for mitigating load-generation imbalance. Requires energy storage to discharge real power for durations up to 30 minutes. The reference duty cycle for analysis is standby for infrequent events characterized by 15-minute FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application D: Regulation Control (RC) – system frequency regulation in concert with load following. The reference duty cycle for analysis is characterized by continuous cycles equivalent to 7.5-minute FPD and charge cycle (triangular waveform), 2 cycles per hour deployed with 10 minutes advance notice. Valued at market rates.

Application E: Spinning Reserve (SR) – reserve power for at least 2 hours with 10 minute notice. The reference duty cycle for analysis is standby for infrequent events characterized by 2-hour FPD, 1 event per day, 10 events per year. Valued at market rates.

Application F: Short Duration Power Quality (SPQ) – capability to mitigate voltage sags (e.g., recloser events). The reference duty cycle for analysis is standby for infrequent events characterized by 5 seconds FPD, 1 event per hour, 5 events per day, 100 events per year. Valued at the cost of alternative solutions.

Application G: Long Duration Power Quality (LPQ) – SPQ, plus capability to provide several hours reserve power. The reference duty cycle for analysis is standby for infrequent events characterized by SPQ plus standby for 4 hours FPD, 1 event per year. Valued at the cost of alternative solutions.

Application H: 3-hr Load Shifting (LS3) – shifting 3 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 3-hour FPD, 1 event per day, 60 events per year. Valued at market rates.

Application I: 10-hr Load Shifting (LS10) – shifting 10 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 10-hour FPD, 1 event per day, 250 events per year. Valued at market rates.

Combined Function Applications (In the Order Noted)

Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC)

Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR)

Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR)

Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR)

Application C5: Combined Applications I, D, E (LS10 + RC + SR)

VRB System Compliance With Application Requirements

The VRB battery plant[13] performance parameters discussed in previous sections were used to develop approximate sizes and operational parameters for systems meeting the application

[13] Note that cost and performance data for VRB systems are presented for reference "plants" as opposed to individual modules as is done for some other technologies in this Handbook. This approach is used to accommodate vendor preferences on the content of disclosed information.

requirements of the selected applications listed above. Key factors in sizing VRB systems include:

- Selection of the optimal amount of stored energy for the application duty cycle consideration under, i.e., the cost effective volume of liquid electrolyte.
- State-of-charge management to ensure that the required power and energy are accessible and that the battery is appropriately recharged for the duty cycle.
- Flow rate management to ensure the capability to deliver stored energy efficiently, e.g., minimal flow is required during standby while higher flow rates may be appropriate for applications requiring prompt response.
- Selection of the optimal battery string voltage for the application, i.e., higher voltages generally allow lower PCS costs but cause higher shunt current losses which, depending upon the duty cycle, may be economically significant.
- Selection of the appropriate pulse factor for the application, i.e., pulse capability depends on both state-of-charge and flow rate, and maintaining high states of charge and flow rates can increase standby losses and limit duty cycle options.

Performance aspects of VRB battery systems for the selected applications are summarized in Table 10-3. The reference power for all applications is 10 MW_{ac}. VRB battery plants nominally rated for 3-, 8- and 10-hour discharges are designated VRB-3h, VRB-8h and VRB-10h, respectively. In consultation with vendors, a voltage window of 600 to 300 V_{dc} has been selected for the applications considered herein, and the pulse factor for a few seconds discharge duration is limited to 1.5. As discussed later, these relatively low values make it necessary to adapt the PCS cost methodology described in Chapter 5. Also, battery stacks are replaced at 10 years, and cycle life is not considered to be a limitation. The VRB system configurations for the selected applications are described below:

Table 10-3
VRB Battery System Compliance With Application Requirements

Applications	Single Function	Combined Function			
	App I: LS10 -- 10 hr FPD per cycle, 250d/yr	App C2: SPQ + LS10 + RC + SR	App C3: SPQ + LS3 + RC + SR	App C4: LPQ + LS3 + RC + SR	App C5: LS10 + RC + SR
Battery Selection					
VRB Battery Plant	VRB-10h	VRB-10h	VRB-3h	VRB-8h	VRB-10h
Pulse Factor	1.0	1.5	1.5	1.0	1.0
Max Charge Voltage	600	600	600	600	600
Min Discharge Voltage	300	300	300	300	300
Replacement Interval, yr	10	10	10	10	10
PCS Selection					
PCS Type (Chapter 5) (See Note 1)	II	I*	I*	I+SST	II
Duty Cycles					
Grid Support or Power Quality (GS or PQ)					
Power, MW		10	10	10	
Event Duration, Hr		0.001	0.001	4	
Load Shifting (LS)					
Power, MW	10	6.7	6.7	10.0	10.0
Load Shift Energy, MWh/yr	25,000	16,667	1,200	1,800	25,000
Load Shift Losses, MWh/yr	9,626	6,417	462	693	9,626
Regulation Control (RC)					
Power, MW		6.7	6.7	10.0	10.0
Hours per day, hr		20	20	20	20
Days per year, days		105	295	295	105
RC, MW-Hours/yr		14,000	39,333	59,000	21,000
RC Losses, MWh/yr		1,348	3,786	5,679	2,021
Spinning Reserve (SR)					
Power, MW		6.7	6.7	10	10.0
SR, MW-Hours		7,279	15,973	23,872	10,920
SR Losses, MWh/yr		51	51	77	77
Summary System Data					
Standby Hours per Year	3,260	1,116	2,420	2,411	1,116
System Net Efficiency, % (See Note 2)	86.9%	90.5%	93.9%	91.1%	85.9%
VRB Standby Efficiency, % (See Note 3)	98.6%	99.7%	99.3%	99.0%	99.5%
PCS Standby Efficiency, %	99.3%	99.7%	99.4%	99.4%	99.7%
System Footprint, MW/sqft (MW/m^2)	0.0007 (0.0078)	0.001 (0.0112)	0.001 (0.0112)	0.0007 (0.0078)	0.0007 (0.0078)
VRB Footprint, MW/sqft (MW/m2)	0.0008 (0.0086)	0.0012 (0.0129)	0.0012 (0.0129)	0.0008 (0.0086)	0.0008 (0.0086)

Notes:
1. PCS Type I costs are adjusted for continuous rating, see text
2. System net efficiency includes losses for energy conversion and system standby expressed on an annual basis, i.e., one minus inefficiency, where inefficiency equals the ratio of annual energy losses to the product of system rated power times 8760 hours, expressed in percent.
3. In consultation with vendors, a standby loss of 3.5% of nominal power has been assigned.

- Application I: 10-hr Load Shifting (LS10) – This application requires that the system provide 10-hour load shifting on a scheduled basis, i.e., prompt PCS response is not required and no PCS standby losses occur. The VRB-10h system with minimum discharge voltage of 300 V_{dc} and pulse factor of 1.0 is equipped with a Type II PCS sized for the continuous rating of 10 MW_{ac}. Losses attributed to shunt currents and electrolyte pumping result in a standby efficiency of 98.6%.
- Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR) – This application requires that the system continuously detect and mitigate infrequent SPQ events lasting up to 2 seconds and other functions as determined to be cost effective. The VRB-10h system with minimum discharge voltage of 300 V_{dc} and pulse factor of 1.5, corresponding to a continuous rating of 6.7 MW_{ac}, is equipped with a Type I PCS sized for the continuous rating. This system will also provide load shifting for 10 hours per day, plus RC and SR, at 6.7 MW_{ac}. RC is provided for 20 hours per day, 105 days per year, and SR for the remainder of the year. Because of the essentially continuous duty cycle associated with LS10 and RC functions, the VRB system spends very little time in standby mode, resulting in a standby efficiency of 99.7%.
- Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR) – This application is the same as Application C2 except the load shifting duty cycle requires 3 hours instead of 10 hours. In this case, the VRB-3h system with minimum discharge voltage of 300 V_{dc} and pulse factor of 1.5, corresponding to a continuous rating of 6.7 MW_{ac}, is equipped with a Type I PCS sized for the continuous rating. In addition to mitigating power quality events, this system will also provide load shifting for 3 hours per day, plus RC and SR, at 6.7 MW_{ac}. RC is provided for 20 hours per day, 295 days per year, and SR for the remainder of the year. The VRB system spends very little time in standby mode, resulting in a standby efficiency of 99.3%.
- Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR) – This application requires that the system continuously detect and mitigate infrequent SPQ events lasting up to 2 seconds, as well as provide full outage protection for up to 4 hours. The VRB-8h system with minimum discharge voltage of 300 V_{dc} and pulse factor of 1.0 is equipped with a Type I PCS (and static transfer switch) sized for the continuous rating of 10 MW_{ac}. In addition to mitigating power quality events, this system will also provide load shifting for 3 hours per day, plus RC and SR, at 10 MW_{ac}. RC is provided for 20 hours per day, 295 days per year, and SR for the remainder of the year. The VRB system spends very little time in standby mode, resulting in a standby efficiency of 99.0%.
- Application C5**:** Combined Applications I, D, E (LS10 + RC + SR) – This application requires that the system provide 10-hour load shifting, regulation control and spinning reserve functions on a scheduled basis, i.e., prompt PCS response is not required and no PCS standby losses occur. The VRB-10h system with minimum discharge voltage of 300 V_{dc} and pulse factor of 1.0 is equipped with a Type II PCS sized for the continuous rating of 10 MW_{ac}. RC is provided for 20 hours per day, 105 days per year, and SR for the remainder of the year. Because of the essentially continuous duty cycle associated with LS10 and RC functions, the VRB system spends very little time in standby mode, resulting in a standby efficiency of 99.5%.

Benefit and Cost Analyses

VRB Battery Pricing and Integrated System Costs

VRB vendors have continued to make steady progress toward commercialization of product lines in both the U.S. and Japan. The cost and performance data shown herein were developed in consultation with leading suppliers and are deemed to be representative but, for a variety of circumstances related to evolving market positions, these data are not directly associated with a specific supplier. For the reference deployment date of 2006 and power rating of 10MW_{ac} used herein, nominal unit prices for the VRB battery scope of supply corresponding to a 10 MW_{ac} plant with 3-, 8- and 10-hour storage are as shown below,[14] along with mature prices projected for 2010 and beyond.

VRB Plant	2006 Prices, K$	Mature Prices, K$
VRB-3h	$12,000	$8,800
VRB-8h	$17,000	$12,400
VRB-10h	$20,000	$14,600

The VRB scope of supply includes the battery stacks, pumps, heat exchangers, plumbing and electrolyte tanks, plus technical support for system integration, installation and startup.

The cost of integrated VRB systems is obtained by combining the cost of the VRB battery scope of supply with the appropriate PCS and BOP costs as described in Chapter 5. The PCS and BOP costs shown in Table 10-4 are based on the methodology described in Chapter 5, adapted slightly to accommodate the relatively low VRB discharge voltage (300 V_{dc}) and pulse factor (1.5). PCS costs are based on Types I or II and, for pulse applications (e.g., SPQ), then adjusted to the continuous rating, e.g., the continuous PCS rating for a 10 MW_{ac} pulse application with factor of 1.5 is 6.7 MW_{ac}. In Table 10-4, initial costs include acquisition, space and installation costs; fixed O&M costs include projected annual costs for parts and labor, plus annual property taxes and insurance (based on 2% per year of the initial total capital costs); and variable O&M costs include standby losses and variable consumables. Disposal costs are deemed negligible and not included.

Since VRB systems require an operating temperature regime of +5 to +35 degrees centigrade and provisions for handling the potential evolution of hydrogen gas, the cost of interior space with environmental conditioning is included at $100/sqft in accordance with provisions in Chapter 5.

[14] The reference energy storage capacity for leading emerging flow battery technologies is 10 hours. A representative price for VRB systems over the range of 8 to 12 hours storage can be obtained by applying increments/decrements at the rate of $150/kWh.

In addition, battery stacks are replaced at 10 years at a cost of 50% of the mature price (cycle life is not considered to be a limitation).

Table 10-4
Capital and Operating Costs for VRB Battery Systems

Applications	Single Function	Combined Function			
	App I: LS10 -- 10 hr FPD per cycle, 250d/yr	**App C2: SPQ + LS10 + RC + SR**	**App C3: SPQ + LS3 + RC + SR**	**App C4: LPQ + LS3 + RC + SR**	**App C5: LS10 + RC + SR**
VRB Battery Capacity, MWhac	100	67	20	40	100
PCS Initial Cost, $/kW	397	311	311	516	397
BOP Initial Cost, $/kW	100	100	100	100	100
VRB Battery Initial Cost, $/kW	2,125	1,417	883	1,825	2,125
VRB Battery Initial Cost, $/kWh	213	213	442	456	213
Total Capital Cost, M$	26.2	18.3	12.9	24.4	26.2
O&M Cost – Fixed, $/kW-year	54.8	38.8	28.1	51.2	54.8
O&M Cost– Variable, $/kW-year	7.0	1.9	4.1	5.2	2.4

Note: The total initial cost may be calculated in two ways:
1. By mutiplying the sum of PCS, BOP and Battery initial costs expressed in $/kW by the reference power,
2. OR by mutiplying the sum of PCS and BOP expressed in $/kW by the reference power and then adding the product of Battery Initial cost expressed in $/kWh and the Battery Capacity

Fixed O&M costs for the PCS are based on $2/kW as required by provisions in Chapter 5, plus VRB battery maintenance in accordance with vendor recommendations. Maintenance activities include:

- Confirming the operability of system protective devices
- Calibrating sensors and instrumentation
- Inspecting for unusual vibrations, noise or odors
- Inspecting for abnormal conditions of connecting cables and piping
- Inspecting insulation resistance

- Servicing the battery controller, pumps, fans, and other system components

Based on vendor input, annual fixed O&M costs for 8 labor-days at $50 per hours are included in the assessment.

Lifecycle Benefit and Cost Analysis for VRB Battery Systems

Further insight to the value of energy storage can be gained through lifecycle cost analyses using a net present value (NPV) methodology and comparison with alternatives. For the convenience of the reader, the financial parameters and electric rate structure set forth in Chapters 4 and 5 and used in the analyses are summarized in Table 10-5 and Table 10-6.

Table 10-5
Financial Parameters

Dollar Value	2003
System Startup	June 2006
Project Life, years	20
Discount Rate (before tax), %	7.5
Property Taxes & Insurance, %/year	2
Fixed Charge Rate, %/year	9.81

Table 10-6
Electric Rates

Load Shifting On Peak Period	3	10
Number Cycles per year	60	250
On-Peak Energy, $/MWh	120	80
Off-Peak Energy, $/MWh	20	
Yearly Average Energy Charge, $/MWh	38	
Regulation Control, $MW-Hour (power), $/MWh	16	
Spinning Reserve, $MW-Hour (power), $/MWh	3	
Transmission Demand Charge, $/kW-mo	5	

The results of lifecycle cost benefit analyses of select VRB battery applications are summarized in Table 10-7 and discussed below. The bases and methodology used in valuing energy storage applications are described in detail in Chapter 4. The details of the cost benefit analysis for each application are discussed below.

Table 10-7
Summary of Benefit and Cost Analyses of VRB Battery Systems

Applications	Single Function	Combined Function			
	App I: LS10 -- 10 hr FPD per cycle, 250d/yr	App C2: SPQ + LS10 + RC + SR	App C3: SPQ + LS3 + RC + SR	App C4: LPQ + LS3 + RC + SR	App C5: LS10 + RC + SR
Alt Solution Value, $/kW	750	1,500	1,500	2,000	750
Initial Installed Cost, M$	26.22	18.28	12.94	24.42	26.22
Total Costs, M$	(36.1)	(24.8)	(17.6)	(33.2)	(35.6)
Total Benefits, M$	37.1	29.9	22.5	31.3	40.1
Benefit to Cost Ratio	1.03	1.21	1.28	0.94	1.13
NPV, M$	1.1	5.1	4.9	(1.9)	4.5
VRB Plant Designation	VRB-10h	VRB-10h	VRB-3h	VRB-8h	VRB-10h
VRB Plant 2006 Price, M$	20.0	20.0	12.0	17.0	20.0
VRB Price for NPV=0, M$	20.8	25.4	17.3	15.7	23.1

- Application I: 10-hr Load Shifting (LS10) – This application was evaluated on the assumption that an alternative solution capable of avoiding upgrade costs can be obtained for net capitalized costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. In addition, the benefits of market rates for on-peak energy and demand charges and off-peak energy rates to recharge the battery are included. As shown in Table 10-7, this application yields a NPV of $1.1 million for an initial investment of about $26.2 million, corresponding to a benefit to cost ratio of 1.03. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 10-6 illustrates the change in NPV over a range of $500 to $1000/kW and shows that VRB systems will compete favorably against alternative solutions costing more than about $650/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of VRB-10h plants were increased from $20 to $20.8 million, the NPV would equal zero, i.e., costs and benefits would be equal at the alternative solution value of $750/kW.

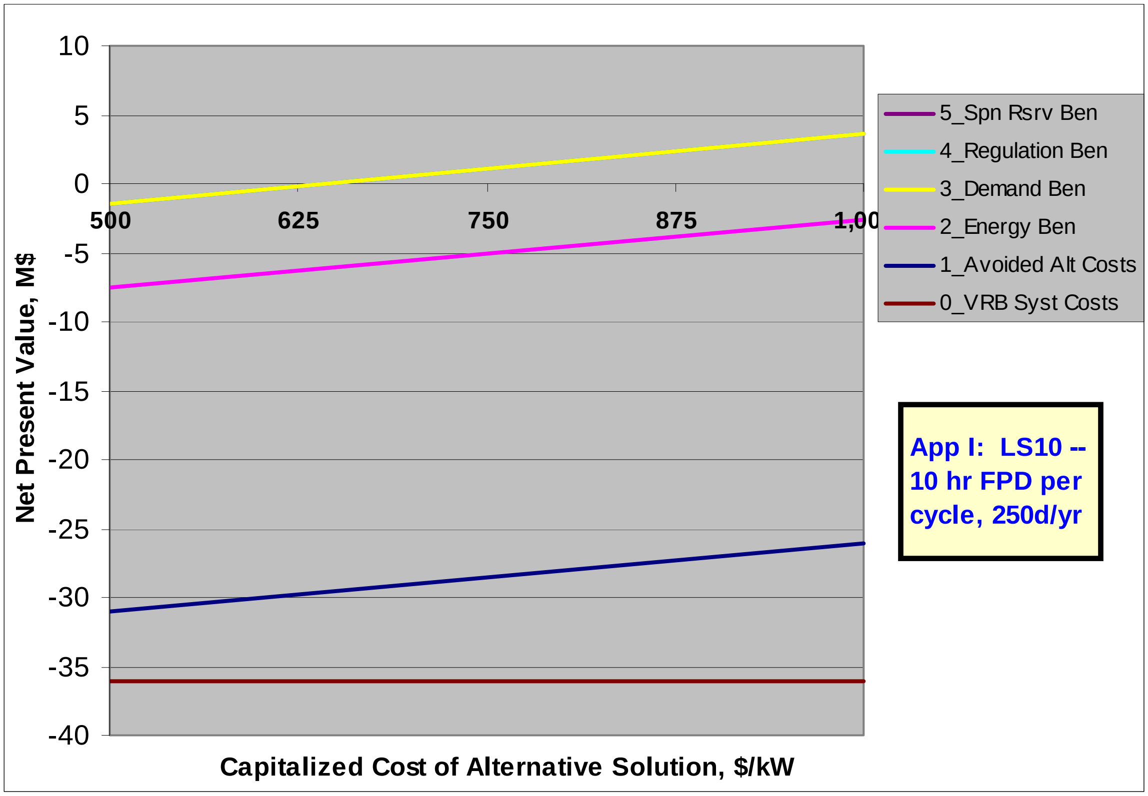

Figure 10-6
Application I: VRB System NPV vs Cost of Alternative Solution

- Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating SPQ events, plus avoid LS10 related upgrade costs, can be obtained for net capitalized costs of about $1500/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 10-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Table 10-7, this application yields a NPV of $5.1 million for an initial investment of about $18.3 million on this basis, corresponding to a benefit to cost ratio of 1.21. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 10-7 illustrates the change in NPV over a range of $1000 to $2000/kW, as well as the incremental value of load shifting (both energy and demand), regulation control and spinning reserve functions. With these value elements, VRB systems will compete favorably against alternative solutions costing more than about $1000/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of VRB-10h plants were increased from $20 to $25.4 million, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $1500/kW.

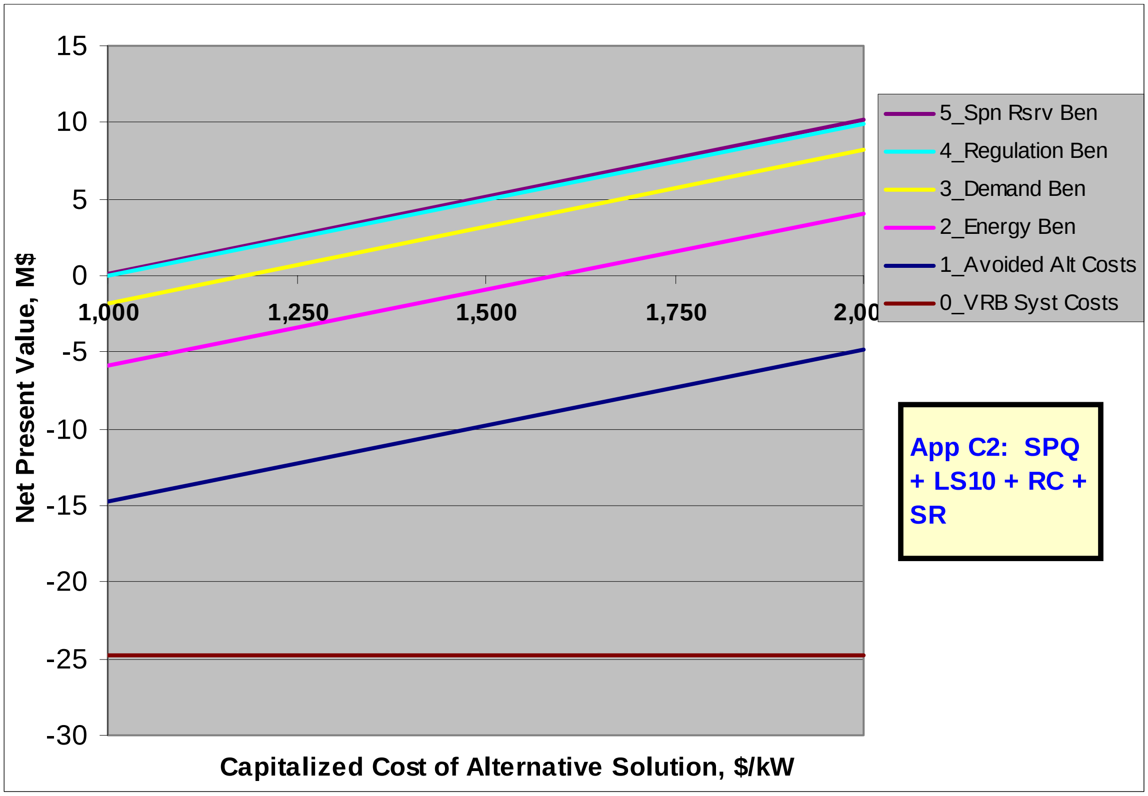

Figure 10-7
Application C2: VRB System NPV vs Cost of Alternative Solution

- Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating SPQ events, plus avoid LS3 related upgrade costs, can be obtained for net capitalized costs of about $1500/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 3-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Table 10-7, this application yields a NPV of $4.9 million for an initial investment of about $12.9 million on this basis, corresponding to a benefit to cost ratio of 1.28. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 10-8 illustrates the change in NPV over a range of $1000 to $2000/kW, as well as the incremental value of load shifting (both energy and demand), regulation control and spinning reserve functions. With these value elements, VRB systems will compete favorably against alternative solutions costing more than about $1000/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of VRB-3h plants were increased from $12 to $17.3 million, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $1500/kW.

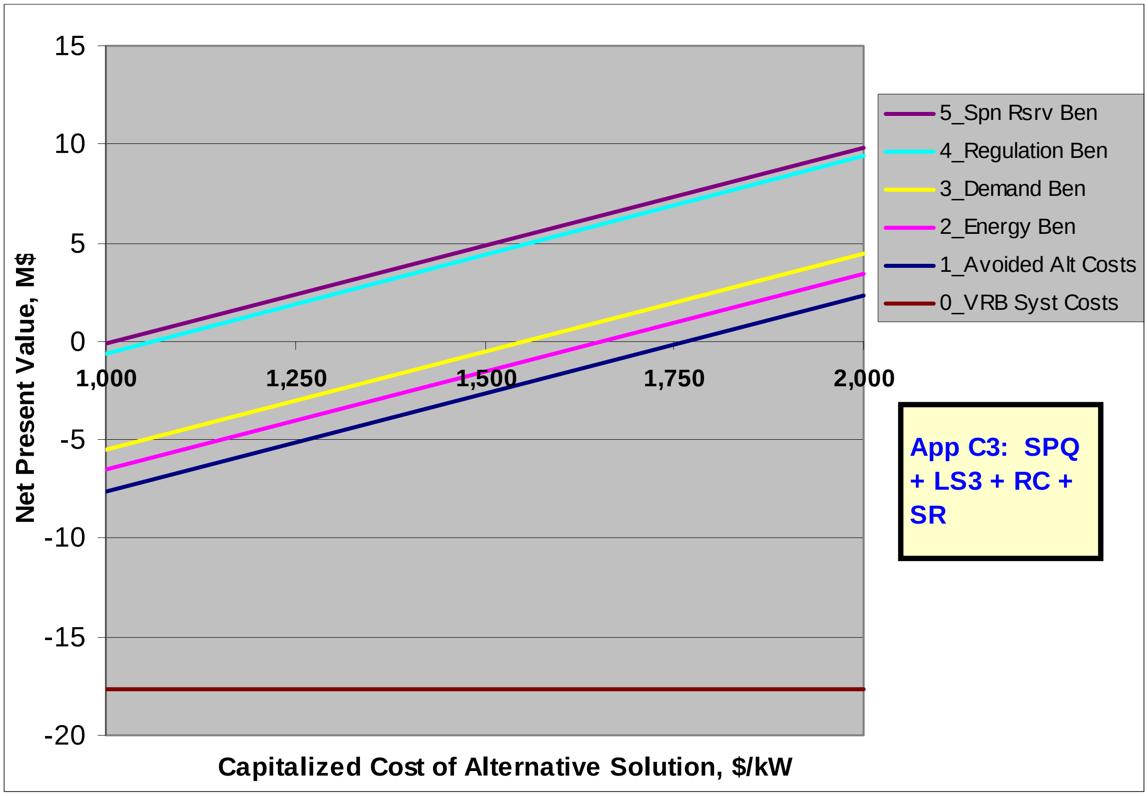

Figure 10-8
Application C3: VRB System NPV vs Cost of Alternative Solution

- Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating LPQ events, plus avoid LS3 related upgrade costs, can be obtained for net capitalized costs of about $2000/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 3-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Table 10-7, this application yields a negative NPV of $(1.9) million for an initial investment of about $24.4 million on this basis, corresponding to a benefit to cost ratio of 0.94. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 10-9 illustrates the change in NPV over a range of $1500 to $2500/kW, as well as the incremental value of load shifting (both energy and demand), regulation control and spinning reserve functions. With these value elements, VRB systems will compete favorably against alternative solutions costing more than about $2200/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of VRB-8h plants were decreased from $17 to $15.7 million, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $2000/kW.

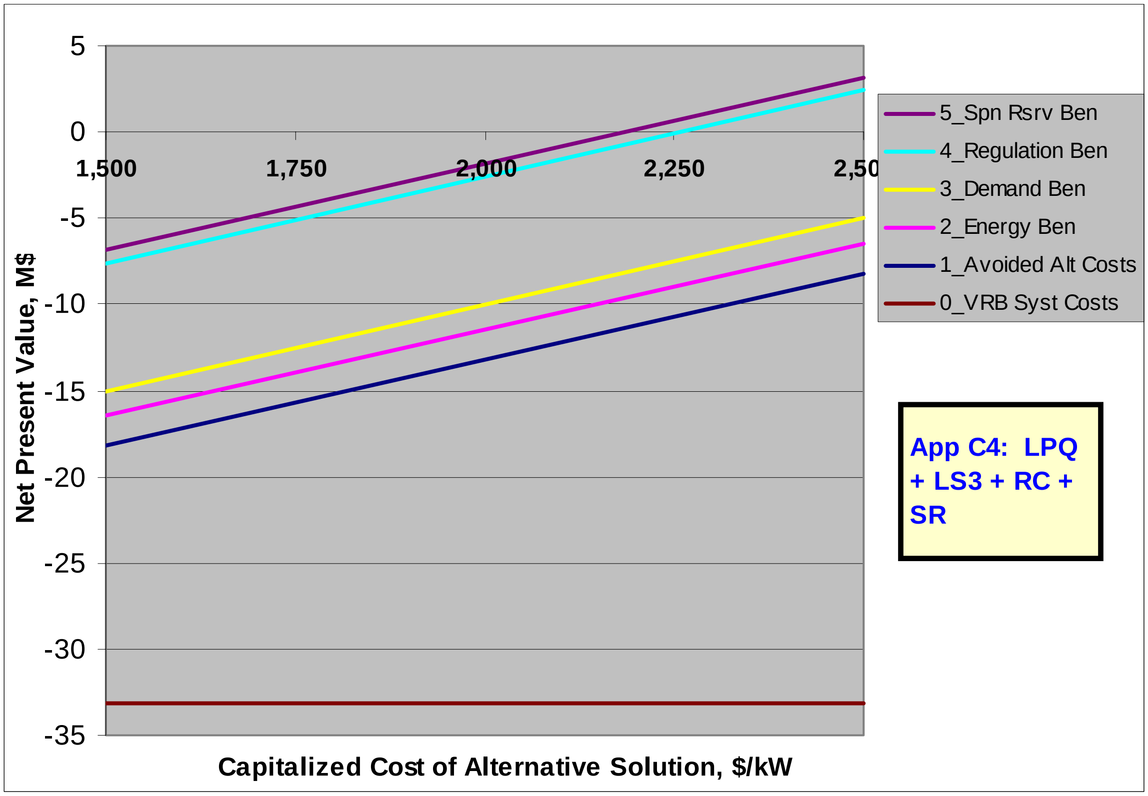

Figure 10-9
Application C4: VRB System NPV vs Cost of Alternative Solution

- Application C5: Combined Applications I, D, E (LS10 + RC + SR) – This application was evaluated on the assumption that an alternative to LS10 related upgrade costs can be obtained for net capitalized costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. In addition, market rates for 10-hour load shifting, regulation control, and spinning reserve are included in the valuation. As shown in Table 10-7, this application yields a NPV of $4.5 million for an initial investment of about $26.2 million on this basis, corresponding to a benefit to cost ratio of 1.13. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 10-10 illustrates the change in NPV over a range of $500 to $1000/kW and shows that VRB systems will compete favorably against alternative solutions over this range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of VRB-10h plants were increased from $20 to 23.1 million, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $750/kW.

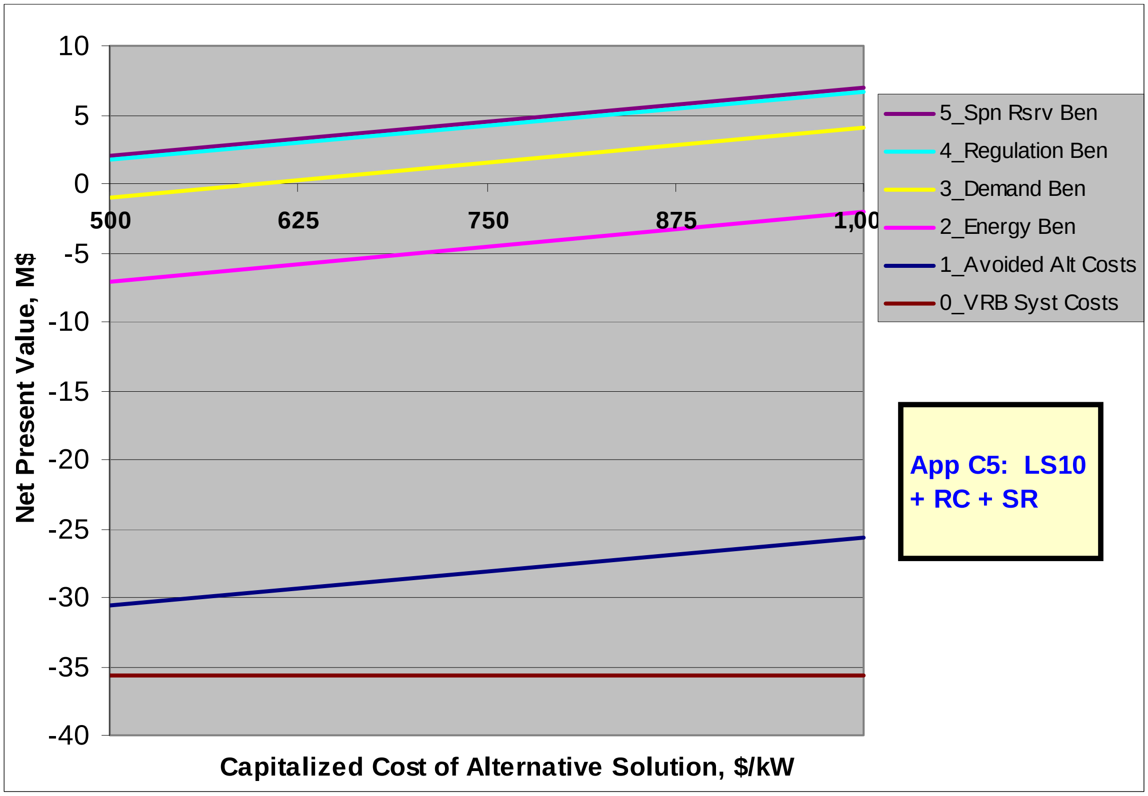

Figure 10-10
Application C5: VRB System NPV vs Cost of Alternative Solution

Interpreting Results from Benefit-Cost Analyses

In general, VRB battery systems are expected to be most competitive for applications requiring several hours stored energy. At this point in their development, VRB systems are penalized by relatively low battery string voltage which results in higher PCS costs than most competing technologies.

The reader is reminded that the foregoing analyses are intended as a guide to the initial consideration of energy storage options, and that these analyses are based on representative electric rates and costs for alternative solutions as described in Chapter 4. The assumptions used herein should be reviewed in light of project specific applications, alternative solutions, electric rates and financial parameters.

References

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11
POLYSULFIDE - BROMIDE BATTERIES

Introduction

Polysulfide Bromide Batteries (PSB) are flow batteries[15] based on a reversible electrochemical reaction between two salt solution electrolytes (sodium bromide and sodium polysulfide). The PSB system has been under development over the past decade, under the brand name Regenesys, by RWE's subsidiary Innogy (formerly National Power) of the United Kingdom. Innogy has created a stand-alone business unit for the furtherance of this development work named Regenesys Technologies Ltd. [1], referred to in the rest or this chapter as "RGN".

Flow batteries have a number of inherent advantages including:

- Separate power and energy ratings, power being a function of the number of battery cells and energy being a function of the volume of electrolyte;
- Easy thermal management, so that life and performance can be maximized;
- Amenable to the use of bipolar cell-stack arrangements, so that the costs for high-voltage, multi-cell batteries can be minimized;
- Being less affected by overcharge, overdischarge and partial state-of-charge cycling, as compared to most other batteries, so that they can be used in applications of interest to electric utilities without life degradation; and
- Having a means to chemically manage the electrolytes for the entire battery, so that, for example, individual cell watering, as is required for flooded lead acid or nickel cadmium cells, is not required.

Counterbalancing these advantages are some disadvantages that result from using flowing electrolytes, and the pumps that are required to affect the flow, as follows:

- Pumps, plumbing and pipework add complexity and cost to the battery;
- Flow batteries are more prone to leakage than other systems, because of the required plumbing – leading to potential concern over environmental containment of the electrolytes;
- They have extra, non-electrochemical components that may occasionally need repair, implying that there could be additional maintenance costs to affect any required repairs to the auxiliary equipment, as compared to batteries without such auxiliary equipment;

[15] A flow battery is one in which one or more of the liquid reactants or products is stored in tanks external to the battery cells and circulated between the tanks and electrodes within the cells by pumps.

- They have lower than desirable efficiency because of the energy consumed to provide the flowing electrolytes, thus operating costs may be higher for flow batteries than for batteries based on more conventional chemistries;
- Electrolytes need to be maintained and managed to maintain the correct pH level to allow the desired electrochemical reactions to take place; and
- Relatively low power and energy densities.

Flow batteries have long been considered one of the best choices, from a life-cycle-cost perspective, for electric utility energy storage when the duration of discharge extends for more than five hours. This is because, in general, the costs of the materials (electrolytes and electrodes) that are electrochemically processed in flow batteries to provide the energy storage are relatively low. In addition, for those flow batteries in which all the active materials remain in solution throughout charge and discharge, such as the Regenesys system, energy capability and power capability can be independently designed into the energy storage system. In this way, the economics of flow batteries are more like pumped-hydro or CAES plants than conventional batteries. This has the effect of allowing minimization of the capital cost for energy storage systems when storage times in the range of ten hours are required.

Description

Regenesys Chemistry

Regenesys is a polysulfide-bromine flow battery, which is sometimes referred to as a regenerative fuel cell. Innogy has been involved in the development of this redox-like system since the early 1990s [2]. However, Regenesys is not truly a redox system since both the positive and negative reactions involve neutral species, unlike a true redox system that involves only dissolved ionic species. The discharge reaction at the positive electrode is:

$$NaBr_3 + 2Na^+ + 2e \rightarrow 3NaBr \qquad \text{Eq. 11-1}$$

and at the negative is:

$$2Na_2S_2 \rightarrow Na_2S_4 + 2Na^+ + 2e \qquad \text{Eq. 11-2}$$

At each electrode, the reverse of the above reactions occur in charge. Sodium ions pass through cation exchange membranes in each of the cells to provide electrolytic current flow and to maintain electroneutrality. The open circuit voltage of a Regenesys cell at a medium state of charge is approximately $1.5V_{dc}$, and this varies non-linearly by about $\pm$ 10% with state of charge.

Note that the electrolyte for the positive electrodes of the Regenesys battery and that for the negatives are quite different. The sulfur that would otherwise be produced from the sodium sulfide solution at the negatives in discharge dissolves in excess sodium sulfide that is present to form sodium polysulfide. The bromine produced at the positives in charge complexes in excess sodium bromide to form sodium tribromide. Unlike the situation in zinc/bromide batteries, the bromine active material remains in solution in the tribromide ion form until it is consumed by the discharge reaction at the positives. Note also that the electrolyte for the positive electrodes is relatively inexpensive, and that used in the negative compartments of the cells is very inexpensive. A block diagram of a Regenesys energy storage plant is shown in Figure 11-1 [16] [3].

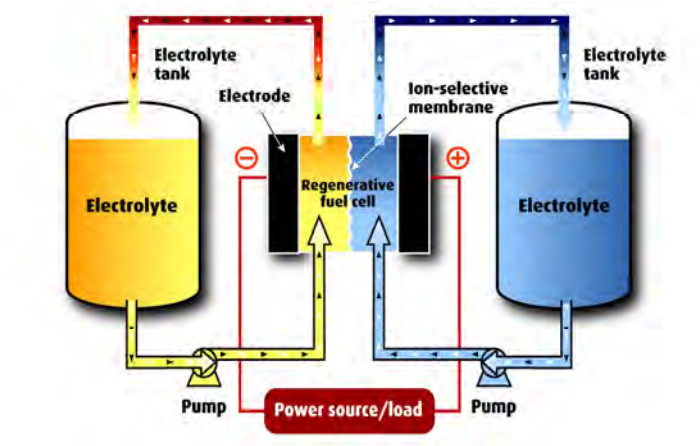

Figure 11-1
Flow Schematic of Regenesys Electricity Storage System

The cation-exchange membranes that are a vital part of the electrochemical operability of Regenesys batteries serve to separate the differing electrolytes in the positive and negative compartments of each cell, yet provide a path for the passage of sodium ions. A rupture of a membrane in one of the cells will allow the electrolyte in the positive compartments and that in the negative compartments to mix together. This precipitates sulfur and would be undesirable, so there are measures to detect and isolate any membrane ruptures. Even when operating properly, no membrane is 100% effective, and some material can pass from one side of the membranes to the other, thereby causing a buildup of a sodium sulfate in the electrolyte for the negative compartments. This contaminating material must be removed as discussed in the following technology section.

Regenesys Technology

Here, the term "technology" is used to encompass the components and equipment that are necessary to allow operation of a rechargeable battery system with the chemistry described in the preceding section. The design approach adopted by RGN for their Regenesys technology is quite different than that of other flow battery developers, or indeed developers of any other battery technology. The RGN design approach results from the needs dictated by the Regenesys

[16] Unless otherwise noted, all figures, diagrams and photos in this chapter are credited to Innogy/Regenesys Technologies, Ltd., which organization retains the copyright thereto. These graphics were downloaded from www.regenesys.com, and this acknowledgment is included in the current document as required as a condition of downloading and reproduction. There is no mention that specific authority to reproduce these graphics is required.

chemistry and by the background of Innogy (i.e., National Power) personnel as employees of an electric utility generating company [4]. Key examples include:

- Other flow battery developers use carbonaceous materials in one form or another for both electrodes and for the bipolar element of their cell-stacks (See Figure 11-2). In RGN stacks, the electrochemical reactions occur at the specially prepared faces of the bipolar electrodes; unlike other redox batteries, carbon felts are NOT used in either cell compartment.
- Significantly larger electrodes (up to 1 square meter instead of a few hundreds of square centimeters, i.e., a small fraction of square meter) are used by RGN as compared to other battery developers. (See Figure 11-3)
- RGN uses higher voltage, 300V versus ~100V or less, and much large capacity cell-stacks, 100 kW versus 5-10 kW, (larger electrodes, more cells in series/stack) as compared to other flow battery developers. (See Figure 11-4)
- Unlike other flow battery developers, RGN utilizes single large tanks for the positive and the negative electrolytes, together with correspondingly large pumps and other auxiliaries, as opposed to the modularized tanks and auxiliaries used by other flow battery developers. (See Figure 11-5)

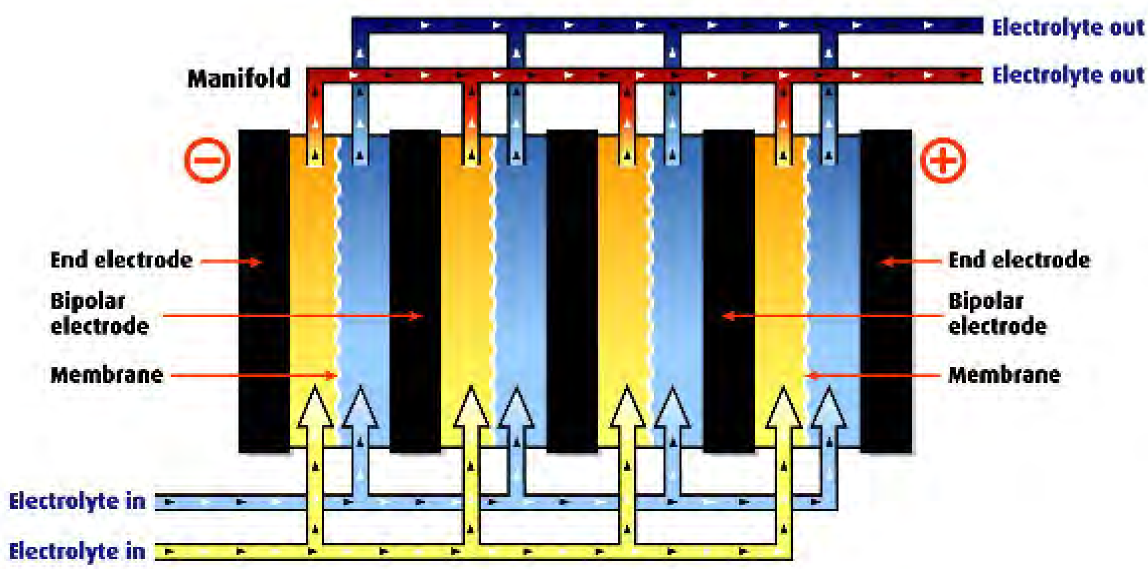

Figure 11-2
Bipolar Cell Stack

Figure 11-3
Sub-Stack Assembly

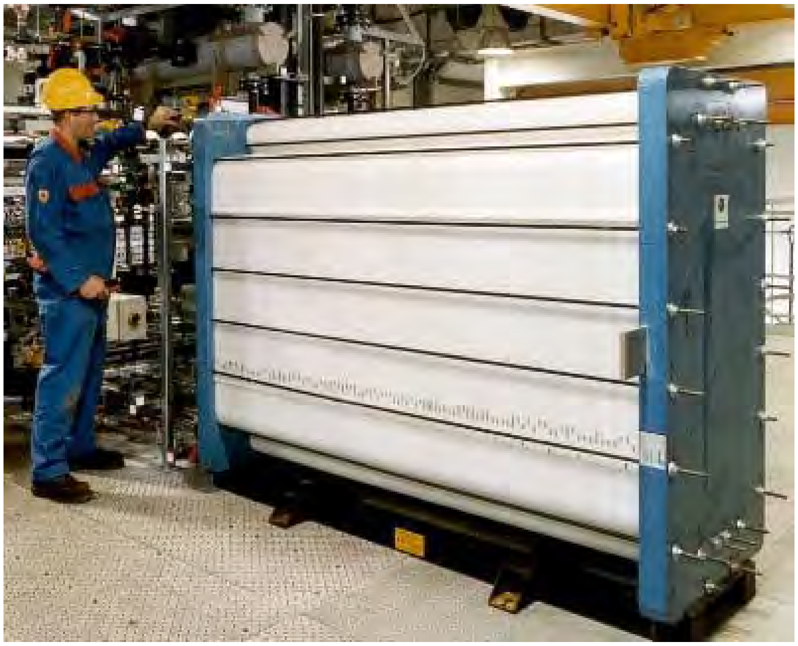

Figure 11-4
Regenesys 100 kW_{dc} XL Module

Figure 11-5
Artist's Rendition of 12 MW_{ac}/100 MWh Regenesys Energy Storage Plant

Regenesys cell stacks consist of bipolar electrode plates spaced and held by insulating polymer frames, see Figure 11-2 above. These frames also serve to manifold and distribute the electrolyte into the cell compartments, which are separated by pieces of membrane material. RGN uses a proprietary sealing arrangement between the frames to prevent electrolyte leakage between cell compartments and out of the stack. As can be seen in Figure 11-4, the frames holding the electrodes and the membranes are held together with thick end plates and tie bars. In the RGN approach to a 12 MW_{ac} Regenesys plant, 120 cell-stacks (100 kW each) are arranged in a parallel and series array for a plant DC voltage of ~3000V. Shunt currents can flow in the hydraulically-parallel flow channels of cells in electrical series, with these shunt currents being limited in all flow batteries by using flow channels that are long enough and narrow enough to provide an effective limiting resistance. However, extra pumping power losses are thereby introduced that must be balanced with the reduction in shunt current losses that can be effected. Shunt current and pumping power losses are thus limited to 5-10% in Regenesys plants by suitable arrangements in the plumbing from the two electrolyte tanks to the individual cells of the cell-stacks.

Plant-wide tanks for each electrolyte, rather than modularized units, are used in the design for a variety of reasons, including the necessity to remove, via a processing unit based on conventional chemical engineering technology, the sodium sulfate that builds up in the negative electrolyte. RGN indicates that such considerations also place a limit, for the next several years at least, on the minimum size plant that can be economically considered (nominally 400 MWh/50 MW_{ac}).

As a result of all the above considerations, the characteristics expected for 400 MWh/50 MW_{ac} Regenesys plant engineered are as follows:

- Space Requirements: RGN's first two demonstration plants (at 100 MWh/12 MW_{ac}) will each occupy approximately 1 hectare (2.5 acres) [5, 6]. 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. It should be noted, however, that since both plant sites had an abundance of space, minimizing footprint was not a design consideration. RGN believes that its next generation, larger capacity plant design will fit on a similar sized site.

- Efficiency: RGN 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 (75 MW_{ac} versus 50 MW_{ac} nominal) are expected to be sustainable for charge and/or discharge cycles, but such higher rates of discharge will reduce the AC-AC efficiency.

- Life: Current plant design life is 15 years. Since there is already considerable experience with the membranes (the expected life-limiting component) under much harsher conditions (i.e., chlor-alkali production), a 15-year life expectation does not appear unwarranted.

- Maintenance Requirements: Within the fifteen year life expected for the plant, RGN projects that 3-month inspections will be necessary, and that routine maintenance and repairs of some of the mechanical components (pumps, valves, etc.) will be needed. Moreover, the crystalline sodium sulfate that is the end product of inefficiency of the membranes (see above) will be continuously collected, flushed, trucked away or disposed of. Sodium sulfate is regarded as an environmentally benign material of low toxicity. Topping off of the polysulphide side of the reaction will take place monthly.

- Likely Environmental Impact, Safety Considerations: Regenesys plants have been designed and configured in such a way as to minimize any environmental impact and to ensure the safety of personnel visiting the plant and that of people living nearby. An Environmental Impact Assessment [7] has been prepared which indicates that a Regenesys plant is environmentally benign.

- Auxiliary Equipment Needs: RGN is using a system approach for design of their Regenesys energy storage plants, and has sourced their AC-DC-AC converters for their first demonstration plants from ABB (see next section for further discussion). RGN intends to provide customers with turnkey storage solutions; no auxiliary equipment other than that provided by itself or its vendors will be needed for Regenesys plants.

The performance characteristics, at a "black box" functional level, of a Regenesys plant are expected to be as follows:

- Typical Electrical Power Limits: The current reference design of a Regenesys plant is for a power output of 50 MW_{ac}. Larger power capabilities are of course possible. The plant can be discharged at 50% higher power than the nominal amount more-or-less continuously, although the efficiency will be lower than at the rated power output. There is no theoretical lower limit to power output, although the efficiency will be lower for very long (very low power) discharges because of the requirements to power auxiliaries.

- Typical Storage Capacities: A minimum storage capacity of 400 MWh (8 hours duration at full power) is planned, with higher capacities being more attractive from an economic perspective.

- Typical Energy to Power Ratios: Although it is theoretically possible to design a Regenesys energy storage plant with a very short discharge time, it appears that longer discharge times, with energy to power ratios of ten or so, are more economically attractive.
- Typical Response Time for Standby to Full-Power Output: A response time of 100ms for standby to full-power output has been specified for the first demonstration plants. 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 is 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. With the appropriate converter specification, response times of 20ms are achievable.

Status

Development Programs

The Regenesys chemistry was not originally developed by RGN, but by Ralph Zito, an independent inventor working at the time in North Carolina, who assigned the rights to his inventions on the Regenesys chemistry and related topics in the early 1990s to RGN. In parallel with Zito's work, RGN performed research to elucidate the Regenesys chemistry, some of which work was contracted to universities in the U.K. RGN also collaborated with DuPont (the manufacturer of Nafion membranes in the U.S.) to try to ensure availability of membrane with both acceptable performance and acceptable cost.

In parallel with the chemical and electrochemical research, RGN initiated a cell stack development effort, engaging a plastics molder (Linpac of Birmingham in the UK) and Electrosynthesis, a technology development company in the Buffalo area of New York State, to assist in these efforts. Ultimately, RGN acquired Electrosynthesis, which continues to work on a variety of electrochemical engineering projects. RGN built many modules of various sizes in their development program, see for example Figure 11-6, with this part of the effort culminating in construction of $100kW_{dc}$ cell stacks (modules) with electrodes of up to one square meter in area.

Figure 11-6
5 kW_{dc} Regenesys Cell-Stack

For their efforts on plant design, RGN contracted with AGRA Birwelco Bristol (an architect-engineer, A&E) in the U.K., and collaborated with this contractor to optimally design a Regenesys energy storage plant. An A&E also assisted with the design of the Regenesys 1 MW test facility at the Aberthaw Power Station in South Wales, U.K., at which several 100 kW modules can be simultaneously tested. This facility has been in operation since the late 1990s.

In addition to these development efforts, RGN have expended significant resources in marketing the Regenesys technology. Included in this part of the work is a significant effort to establish the economic value for their energy storage technology.

Demonstration Projects

Beginning in late 1990s, RGN started a serious effort to find a demonstration site for the Regenesys technology. The first choice was a 10 MW_{ac}/100 MWh plant for energy arbitrage to be sited at the Didcot power station in the U.K. [8], but the site was later changed to the Little Barford power station, also in the U.K. [9]. RGN have announced that by early 2004, they should have completed construction and acceptance testing of a 12 MW_{ac}/100 MWh demonstration plant at the Little Barford power station in the U.K. Progress with construction of the Little Barford Regenesys plant is shown in Figure 11-7.

Of the total storage capacity, 40 MWh is reserved to provide black start for the Little Barford station. The economic benefit for black start is the subject of a proprietary arrangement between Innogy and National Grid. RGN also plans to demonstrate the utility of the Little Barford plant for energy management (arbitrage), and for response (load following) and voltage control for the power network. RGN regards the Little Barford plant a demonstration project and has not attempted to economically justify the plant on the basis of the benefits that can be garnered by it [10].

Figure 11-7
Progress With Regenesys Construction at Little Barford Generating Station

RGN has also contracted to supply the Tennessee Valley Authority (TVA) with a 12 MW_{ac}/100 MWh system that is to be used primarily to provide a higher level of reliability of electrical service to the Columbus Air Force Base (CAFB) in Mississippi [11]. As of late 2003, tanks are in place and the main building is being readied for cell-stacks to be put in place [12]. See Figure 11-8.

The alternative to installing the Regenesys plant would have been a $5 million upgrade to the TVA substation and the sub-transmission system for the CAFB. The converter for the CAFB energy storage plant is rated at 16.8 MW or 19 MVA, so that the plant can be simultaneously used to demonstrate multiple applications, including improved reliability of service, transmission support, provision of ancillary services, and energy arbitrage. Similar to the Little Barford Regenesys plant, the CAFB plant is also a demonstration project for which TVA has not attempted to provide an economic justification.

The first 24 modules for the Little Barford plant have been installed, and are being prepared for commissioning. Manufacturing of the cell stacks for the TVA Regenesys plant will be initiated when those for the Little Barford project have been completed.

Figure 11-8
Exterior and Interior Views of Progress With Construction of Regenesys Energy Storage Plant at Columbus Air Force Base Site

T&D System Energy Storage System Applications

Select Applications for PSB Battery Systems

This section presents the select applications for which PSB batteries are suited and describes the key features of PSB systems configured to meet requirements of select applications. Screening economic analyses have shown that PSB battery systems are potentially competitive for one single function application as well as four of the combined function applications, which are described in detail in Chapter 3. The following list briefly summarizes all of the Chapter 3 applications, with a reiteration of the key application requirements. Those for which PSB batteries are best suited are enclosed with borders

Single Function Applications

Application A: Grid Angular Stability (GAS) – mitigation of power oscillations by injection and absorption of real power at periods of 1 to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 20 oscillatory cycles, cumulatively equivalent to a full power discharge (FPD) of 1-second duration., 1 event per day; 10 events per year. Valued at the cost of alternative solutions.

Application B: Grid Voltage Stability (GVS) – mitigation of degraded voltage by additional reactive power plus injection of real power for durations up to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 1 second FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application C: Grid Frequency Excursion Suppression (GFS) – “prompt” spinning reserve (or load) for mitigating load-generation imbalance. Requires energy storage to discharge real power for durations up to 30 minutes. The reference duty cycle for analysis is standby for infrequent events characterized by 15-minute FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application D: Regulation Control (RC) – system frequency regulation in concert with load following. The reference duty cycle for analysis is characterized by continuous cycles equivalent to 7.5-minute FPD and charge cycle (triangular waveform), 2 cycles per hour deployed with 10 minutes advance notice. Valued at market rates.

Application E: Spinning Reserve (SR) – reserve power for at least 2 hours with 10 minute notice. The reference duty cycle for analysis is standby for infrequent events characterized by 2-hour FPD, 1 event per day, 10 events per year. Valued at market rates.

Application F: Short Duration Power Quality (SPQ) – capability to mitigate voltage sags (e.g., recloser events). The reference duty cycle for analysis is standby for infrequent events characterized by 5 seconds FPD, 1 event per hour, 5 events per day, 100 events per year. Valued at the cost of alternative solutions.

Application G: Long Duration Power Quality (LPQ) – SPQ, plus capability to provide several hours reserve power. The reference duty cycle for analysis is standby for infrequent events characterized by SPQ plus standby for 4 hours FPD, 1 event per year. Valued at the cost of alternative solutions.

Application H: 3-hr Load Shifting (LS3) – shifting 3 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 3-hour FPD, 1 event per day, 60 events per year. Valued at market rates.

Application I: 10-hr Load Shifting (LS10) – shifting 10 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 10-hour FPD, 1 event per day, 250 events per year. Valued at market rates.

<u>Combined Function Applications (In the Order Noted)</u>

Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC)

Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR)
Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR)
Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR)
Application C5: Combined Applications I, D, E (LS10 + RC + SR)

PSB System Compliance With Application Requirements

The PSB battery module performance parameters discussed in previous sections were used to develop approximate sizes and operational parameters for systems meeting the application requirements of the selected applications listed above. Key factors in sizing PSB systems include:

- Selection of the optimal amount of stored energy for the application duty cycle consideration under, i.e., the cost effective volume of liquid electrolyte.
- State-of-charge management to ensure that the required power and energy are accessible and that the battery is appropriately recharged for the duty cycle.
- Flow rate management to ensure the capability to deliver stored energy efficiently, e.g., minimal flow is required during standby while higher flow rates may be appropriate for applications requiring prompt response.

- Selection of the optimal battery string voltage for the application, i.e., higher voltages generally allow lower PCS costs but cause higher shunt current losses which, depending upon the duty cycle, may be economically significant.
- Selection of the appropriate pulse factor for the application, i.e., pulse capability depends on both state-of-charge and flow rate, and maintaining high states of charge and flow rates can increase standby losses and limit duty cycle options.

Performance aspects of PSB battery systems for the selected applications are summarized in Table 11-1. The reference power for all PSB applications is 50 MW_{ac}. As discussed later, this power level makes it necessary to adapt the PCS cost methodology described in Chapter 5. PSB battery modules nominally rated for 240 kW_{ac} and 8- and 10-hour discharges are designated XLD-8h and XLD-10h, respectively. In consultation with Innogy, a voltage window of 3600 to 1315 V_{dc} has been selected for the applications considered herein, and a pulse factor of 1.5 can be applied for discharge durations up to 3 hours. Also, battery stacks are replaced at 15 years, and cycle life is not considered to be a limitation. The PSB system configurations for the selected applications are described below:

Table 11-1
PSB Battery System Compliance With Application Requirements

Applications	Single Function	Combined Function			
	App I: LS10 -- 10 hr FPD per cycle, 250d/yr	App C2: SPQ + LS10 + RC + SR	App C3: SPQ + LS3 + RC + SR	App C4: LPQ + LS3 + RC + SR	App C5: LS10 + RC + SR
Battery Selection					
Type of Modules	XLD-10h	XLD-10h	XLD-8h	XLD-8h	XLD-10h
Number of Modules	208	139	139	208	208
Pulse Factor (See Note 1)	1.0	1.5	1.5	1.0	1.0
Max Charge Voltage	3,600	3,600	3,600	3,600	3,600
Min Discharge Voltage	1,315	1,315	1,315	1,315	1,315
Replacement Interval, yr	15	15	15	15	15
PCS Selection					
PCS Type (Chapter 5)	II	I	I	I+SST	II
Duty Cycles					
Grid Support or Power Quality (GS or PQ)					
Power, MW		50	50	50	
Event Duration, Hr		0.001	0.001	4	
Load Shifting (LS)					
Power, MW	50	33.3	50.0	50.0	50.0
Load Shift Energy, MWh/yr	125,000	83,333	9,000	9,000	125,000
Load Shift Losses, MWh/yr	72,863	48,575	5,246	5,246	72,863
Regulation Control (RC)					
Power, MW		33.3	33.3	50.0	50.0
Hours per day, hr		20	20	20	20
Days per year, days		105	295	295	105
RC, MW-Hours/yr		70,000	196,667	295,000	105,000
RC Losses, MWh/yr		10,201	28,659	42,989	15,301
Spinning Reserve (SR)					
Power, MW		33.3	50.0	50	50.0
SR, MW-Hours		36,390	119,785	119,360	54,600
SR Losses, MWh/yr		389	583	583	583
Summary System Data					
Standby Hours per Year	3,260	1,116	2,420	2,411	1,116
System Net Efficiency, % (See Note 1)	79.9%	85.6%	90.2%	86.3%	78.5%
PSB Standby Efficiency, % (See Note 2)	97.3%	99.4%	98.6%	98.0%	99.1%
PCS Standby Efficiency, %	99.3%	99.7%	99.4%	99.4%	99.7%
System Footprint, MW/sqft (MW/m^2)	0.0005 (0.0051)	0.0007 (0.0074)	0.0007 (0.0074)	0.0005 (0.0051)	0.0005 (0.0051)
PSB Footprint, MW/sqft (MW/m2)	0.0005 (0.0054)	0.0008 (0.0081)	0.0008 (0.0081)	0.0005 (0.0054)	0.0005 (0.0054)

Notes:
1. PSB pulses to 1.5 for up to 3 hours.
2. System net efficiency includes losses for energy conversion and system standby expressed on an annual basis, i.e., one minus inefficiency, where inefficiency equals the ratio of annual energy losses to the product of system rated power times 8760 hours, expressed in percent.
3. In consultation with the vendor, a standby loss as 7% of nominal power has been assigned.

- Application I: 10-hr Load Shifting (LS10) – This application requires that the system provide 10-hour load shifting on a scheduled basis, i.e., prompt PCS response is not required and no PCS standby losses occur. The PSB system using the XLD-10h module with minimum discharge voltage of 1315 V_{dc} and pulse factor of 1.0 is equipped with a Type II PCS sized for the continuous rating of 50 MW_{ac}. Losses attributed to shunt currents and electrolyte pumping result in a standby efficiency of 97.3%.
- Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR) – This application requires that the system continuously detect and mitigate infrequent SPQ events lasting up to 2 seconds and conduct other functions as determined to be cost effective. The PSB system using the XLD-10h module with minimum discharge voltage of 1315 V_{dc} and pulse factor of 1.5 is equipped with a Type I PCS sized for the 50 MW_{ac} application. This system will also provide load shifting for 10 hours per day, plus RC and SR, at 33.3 MW_{ac}. RC is provided for 20 hours per day, 105 days per year, and SR for the remainder of the year. Because of the essentially continuous duty cycle associated with LS10 and RC functions, the PSB system spends very little time in standby mode, resulting in a standby efficiency of 99.4%.
- Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR) – This application is the same as Application C2 except the load shifting duty cycle requires 3 hours instead of 10 hours. In this case, the PSB system using the XLD-8h module (i.e., the shortest duration PSB option current offered) with minimum discharge voltage of 1315 V_{dc} and pulse factor of 1.5 is equipped with a Type I PCS sized for the 50 MW_{ac} application. In addition to mitigating power quality events, this system will also provide SR and load shifting at 50 MW_{ac} for 3 hours per day because of its capability to discharge at a pulse factor of 1.5 for up to 3 hours. RC is provided at 33.3 MW_{ac} for 20 hours per day, 295 days per year, and SR for the remainder of the year. The PSB system spends very little time in standby mode, resulting in a standby efficiency of 98.6%.
- Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR) – This application requires that the system continuously detect and mitigate infrequent SPQ events lasting up to 2 seconds, as well as provide full outage protection for up to 4 hours. The PSB system using the XLD-8h module with minimum discharge voltage of 1315 V_{dc} and pulse factor of 1.0 is equipped with a Type I PCS (and static transfer switch) sized for the 50 MW_{ac} application. In addition to mitigating power quality events, this system will also provide load shifting for 3 hours per day, plus RC and SR, at 50 MW_{ac}. RC is provided for 20 hours per day, 295 days per year, and SR for the remainder of the year. The PSB system spends very little time in standby mode, resulting in a standby efficiency of 98.0%.
- Application C5**:** Combined Applications I, D, E (LS10 + RC + SR) – This application requires that the system provide 10-hour load shifting, regulation control and spinning reserve functions on a scheduled basis, i.e., prompt PCS response is not required and no PCS standby losses occur. The PSB system using the XLD-10h module with minimum discharge voltage of 1315 V_{dc} and pulse factor of 1.0 is equipped with a Type II PCS sized for the 50 MW_{ac} application. RC is provided at 50 MW_{ac} for 20 hours per day, 105 days per year, and SR for the remainder of the year. Because of the essentially continuous duty cycle associated with LS10 and RC functions, the PSB system spends very little time in standby mode, resulting in a standby efficiency of 99.1%.

Benefit and Cost Analyses

PSB Battery Pricing and Integrated System Costs

As previously described, Innogy has made steady progress toward commercialization of Regenesys systems in both the U.K. and U.S. The cost and performance data shown herein were developed in consultation with Innogy and are based on their 240 kW_{ac} "XLD" module (cell stack). At this time, the shortest duration system Innogy is prepared to offer is 10 hours. Similarly, only offer the Regenesys system for applications of 50 MW_{ac} and larger. For convenience of analysis, the cost and space for the XLD module and associated electrolyte storage equipment corresponding to the 8- and 10-hour discharge durations are combined. For the reference deployment date of 2006 and power rating of 50MW_{ac}, nominal unit prices for the PSB battery scope of supply corresponding to XLD modules with 8- and 10- hour storage are as shown below,[17] along with mature prices projected for 2010 and beyond.

PSB Module	2006 Prices, K$	Mature Prices, K$
XLD-8h	$262	$200
XLD-10h	$286	$220

The PSB scope of supply includes the battery stacks, pumps, heat exchangers, plumbing and electrolyte tanks, plus technical support for system integration, installation and startup.

The cost of integrated PSB systems is obtained by combining the cost of the PSB battery scope of supply with the appropriate PCS and BOP costs as described in Chapter 5. The PCS and BOP costs shown in Table 11-2 are based on the methodology described in Chapter 5, adapted slightly to accommodate the 50 MW_{ac} power level at a discharge voltage 1315 V_{dc} and pulse factor (1.5) for appropriate applications. PCS costs are based on Types I or II and, for pulse applications, i.e., PCS costs are first adjust for voltage and then power level according to the methodologies described in Chapter 5. In Table 11-2, initial costs include acquisition, space and installation costs; fixed O&M costs include projected annual costs for parts and labor, plus annual property taxes and insurance (based on 2% per year of the initial total capital costs); and variable O&M costs include standby losses and variable consumables.

Since PSB systems require a controlled environment, the cost of interior space with environmental conditioning is included in data provided by Innogy, along with exterior space for which no controls are necessary, in accordance with the provisions in Chapter 5. In addition, battery stacks are replaced at 15 years at a cost of 50% of the mature price (cycle life is not considered to be a limitation). A disposal cost of $1,000 per module has been assigned.

[17] The reference energy storage capacity for leading emerging flow battery technologies is 10 hours. A representative price for PSB systems over the range of 8 to 12 hours storage can be obtained by applying increments/decrements at the rate of $50/kWh.

Table 11-2
Capital and Operating Costs for PSB Battery Systems

Applications	Single Function	Combined Function			
	App I: LS10 -- 10 hr FPD per cycle, 250d/yr	**App C2: SPQ + LS10 + RC + SR**	**App C3: SPQ + LS3 + RC + SR**	**App C4: LPQ + LS3 + RC + SR**	**App C5: LS10 + RC + SR**
PSB Battery Capacity, MWhac	500	333	150	200	500
PCS Initial Cost, $/kW	103	120	120	170	103
BOP Initial Cost, $/kW	100	100	100	100	100
PSB Battery Initial Cost $/kW	1,312	874	808	1,212	1,312
PSB Battery Initial Cost $/kWh	131	131	269	303	131
Total Capital Cost, M$	75.7	54.7	51.4	74.1	75.7
O&M Cost – Fixed, $/kW-year	80.3	55.9	54.6	79.6	80.3
O&M Cost– Variable, $/kW-year	11.6	2.9	6.4	8.6	4.0
NPV PSB Disposal Cost, $/kW	1.9	1.2	1.2	1.9	1.9

Note: The total initial cost may be calculated in two ways:
1. By mutiplying the sum of PCS, BOP and Battery initial costs expressed in $/kW by the reference power,
2. OR by mutiplying the sum of PCS and BOP expressed in $/kW by the reference power and then adding the product of Battery Initial cost expressed in $/kWh and the Battery Capacity

Fixed O&M costs for the PCS are based on $2/kW as required by provisions in Chapter 5, plus PSB battery maintenance in accordance with vendor recommendations. Maintenance activities include:

- Confirming the operability of system protective devices
- Calibrating sensors and instrumentation
- Removing sedimentation
- Inspecting for unusual vibrations, noise or odors
- Inspecting for abnormal conditions of connecting cables and piping
- Inspecting insulation resistance

- Servicing the battery controller, pumps, fans, and other system components

Based on Innogy input, annual fixed O&M costs are included at a rate of $48/kW-year. In addition, an allowance for annual property taxes and insurance is included, based on 2% of the initial total capital costs.

Lifecycle Benefit and Cost Analysis for PSB Battery Systems

Further insight to the value of energy storage can be gained through lifecycle cost analyses using a net present value (NPV) methodology and comparison with alternatives. For the convenience of the reader, the financial parameters and electric rate structure set forth in Chapters 4 and 5 and used in the analyses are summarized in Table 11-3 and Table 11-4.

Table 11-3
Financial Parameters

Dollar Value	2003
System Startup	June 2006
Project Life, years	20
Discount Rate (before tax), %	7.5
Property Taxes & Insurance, %/year	2
Fixed Charge Rate, %/year	9.81

Table 11-4
Electric Rates

Load Shifting On Peak Period	3	10
Number Cycles per year	60	250
On-Peak Energy, $/MWh	120	80
Off-Peak Energy, $/MWh	20	
Yearly Average Energy Charge, $/MWh	38	
Regulation Control, $MW-Hour (power), $/MWh	16	
Spinning Reserve, $MW-Hour (power), $/MWh	3	
Transmission Demand Charge, $/kW-mo	5	

The results of lifecycle cost benefit analyses of select PSB battery applications are summarized in Table 11-5 and discussed below. The bases and methodology used in valuing energy storage applications are described in detail in Chapter 4. The details of the cost benefit analysis for each application are discussed below.

Table 11-5
Summary of Benefit and Cost Analyses of PSB Battery Systems

Applications	Single Function	Combined Function			
	App I: LS10 -- 10 hr FPD per cycle, 250d/yr	App C2: SPQ + LS10 + RC + SR	App C3: SPQ + LS3 + RC + SR	App C4: LPQ + LS3 + RC + SR	App C5: LS10 + RC + SR
Alt Solution Value, $/kW	750	1,500	1,500	2,000	750
Initial Installed Cost, M$	75.7	54.7	51.4	74.1	75.7
Total Costs, M$	(126.2)	(87.2)	(84.7)	(122.4)	(122.3)
Total Benefits, M$	180.7	144.9	114.9	150.3	193.3
Benefit to Cost Ratio	1.43	1.66	1.36	1.23	1.58
NPV, M$	54.5	57.7	30.2	27.9	71.0
PSB Module	XLD-10h	XLD-10h	XLD-8h	XLD-8h	XLD-10h
Number of Modules	208	139	139	208	208
PSB 2006 Price, K$/module	286	286	262	262	286
PSB Price for NPV=0, K$/module	488	608	434	363	549

- Application I: 10-hr Load Shifting (LS10) – This application was evaluated on the assumption that an alternative solution capable of avoiding upgrade costs can be obtained for net capitalized costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. In addition, the benefits of market rates for on-peak energy and demand charges and off-peak energy rates to recharge the battery are included. As shown in Table 11-5, this application yields a NPV of $54.5 million for an initial investment of about $75.7 million, corresponding to a benefit to cost ratio of 1.43. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 11-9 illustrates the change in NPV over a range of $500 to $1000/kW and shows that PSB systems will compete favorably against alternative solutions costing more than about $650/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of XLD -10h modules were increased from $286,000 to $488,000, the NPV would equal zero, i.e., costs and benefits would be equal at the alternative solution value of $750/kW.

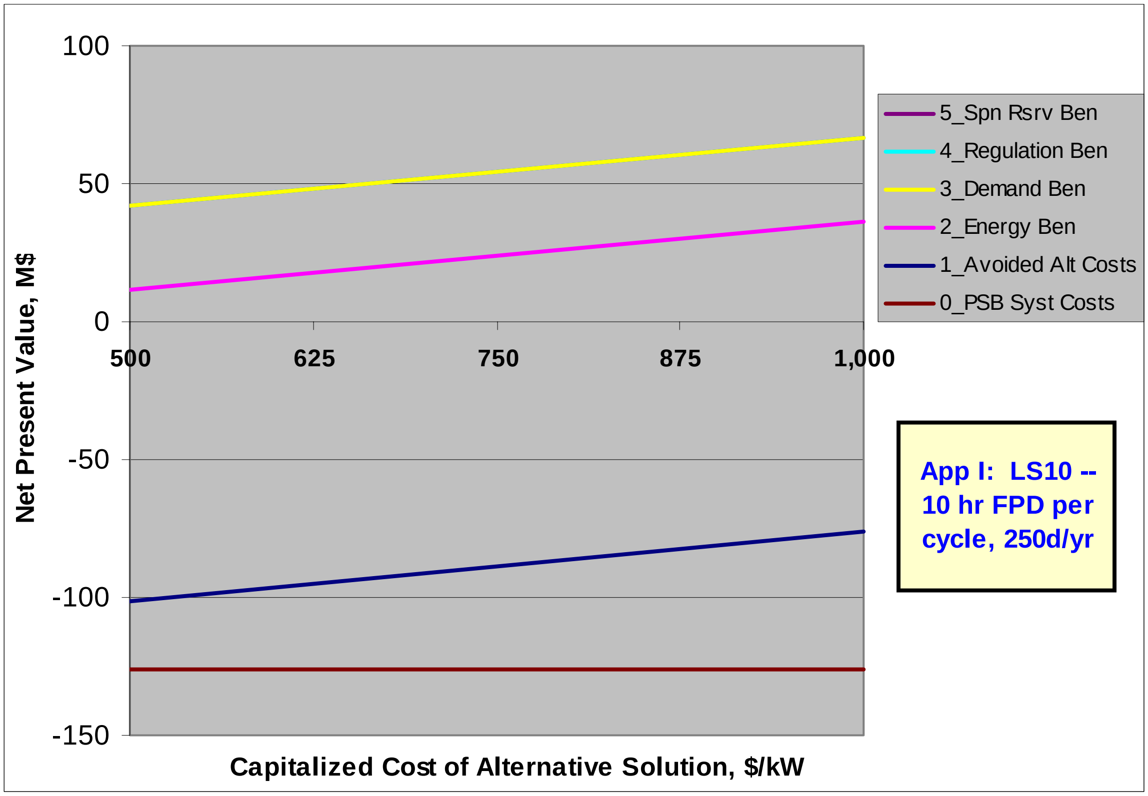

Figure 11-9
Application I: PSB System NPV vs Cost of Alternative Solution

- Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating SPQ events, plus avoid LS10 related upgrade costs, can be obtained for net capitalized costs of about $1500/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 10-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Table 11-5, this application yields a NPV of $57.7 million for an initial investment of about $57.7 million on this basis, corresponding to a benefit to cost ratio of 1.66. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 11-10 illustrates the change in NPV over a range of $1000 to $2000/kW, as well as the incremental value of load shifting (both energy and demand), regulation control and spinning reserve functions. With these value elements, PSB systems will compete very favorably against alternative solutions over the entire range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of XLD -10h modules were increased from $286,000 to $608,000, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $1500/kW.

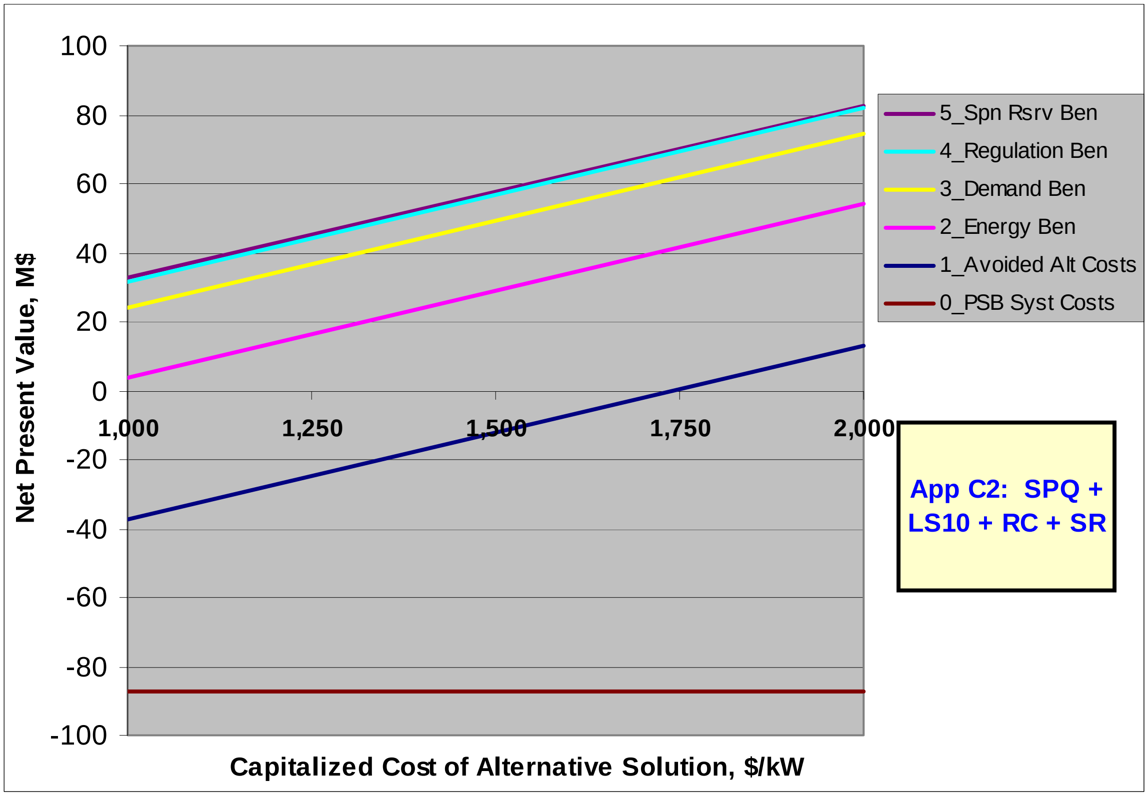

Figure 11-10
Application C2: PSB System NPV vs Cost of Alternative Solution

- Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating SPQ events, plus avoid LS3 related upgrade costs, can be obtained for net capitalized costs of about $1500/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 3-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Tble 11-5, this application yields a NPV of $30.2 million for an initial investment of about $51.4 million on this basis, corresponding to a benefit to cost ratio of 1.36. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 11-11 illustrates the change in NPV over a range of $1000 to $2000/kW, as well as the incremental value of load shifting (both energy and demand), regulation control and spinning reserve functions. With these value elements, PSB systems will compete favorably against alternative solutions costing more than about $1000/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of XLD - 8h modules were increased from $262,000 to $434,000, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $1500/kW.

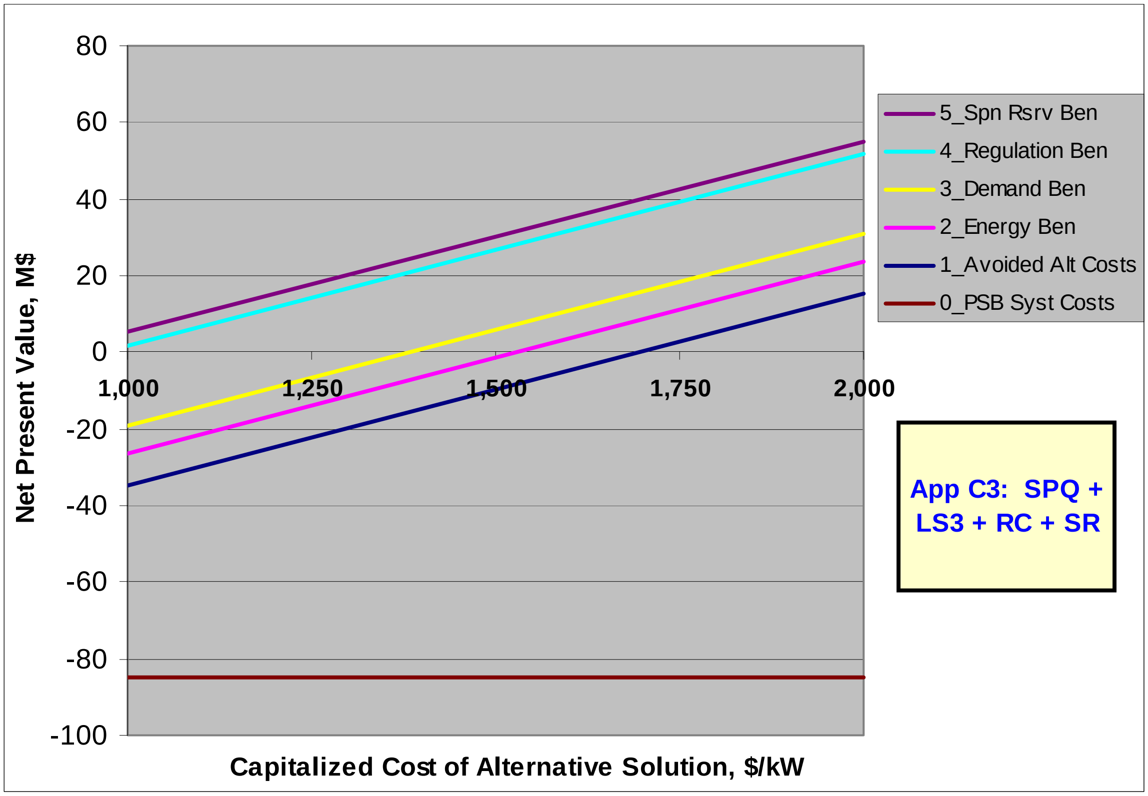

Figure 11-11
Application C3: PSB System NPV vs Cost of Alternative Solution

- Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR) – This application was evaluated on the assumption that an alternative solution capable of mitigating LPQ events, plus avoid LS3 related upgrade costs, can be obtained for net capitalized costs of about $2000/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. The market rates for 3-hour load shifting, regulation control, and spinning reserve are also included in the valuation. As shown in Table 11-5, this application yields a NPV of $27.9 million for an initial investment of about $74.1 million on this basis, corresponding to a benefit to cost ratio of 1.23. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 11-12 illustrates the change in NPV over a range of $1500 to $2500/kW, as well as the incremental value of load shifting (both energy and demand), regulation control and spinning reserve functions. With these value elements, PSB systems will compete favorably against alternative solutions the entire range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of XLD - 8h modules were increased from $262,000 to $363,000, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $2000/kW.

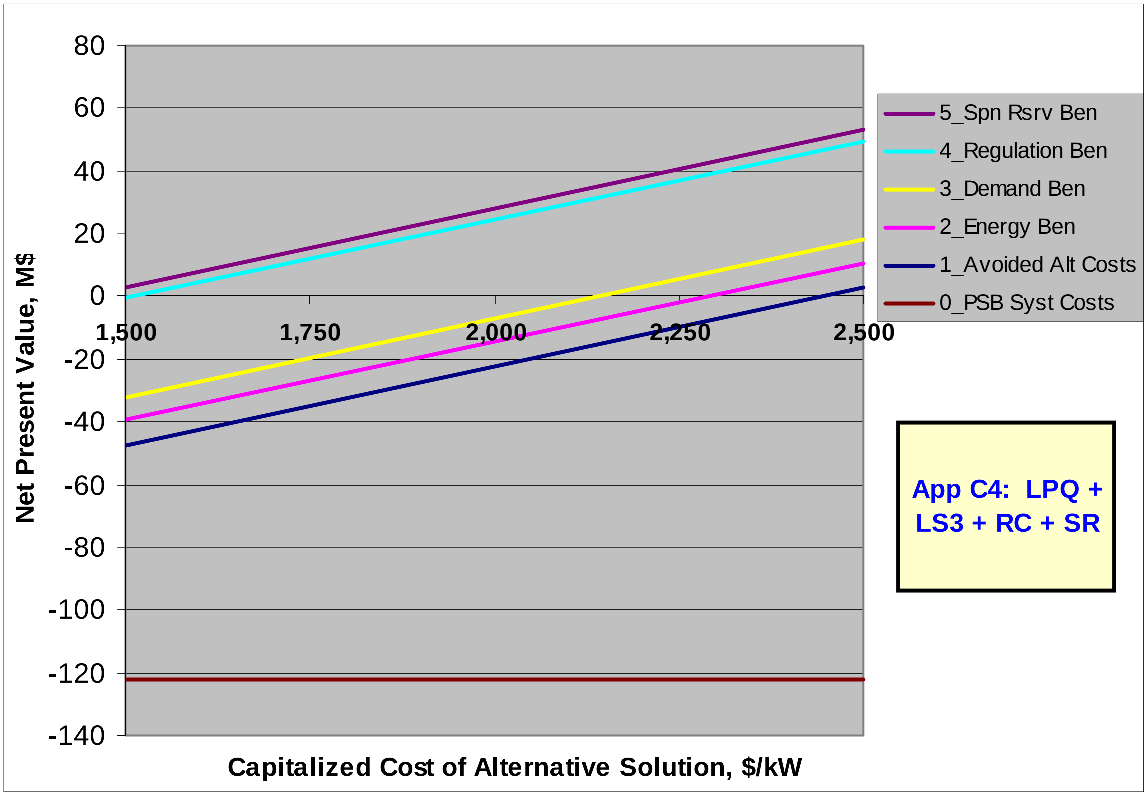

Figure 11-12
Application C4: PSB System NPV vs Cost of Alternative Solution

- Application C5: Combined Applications I, D, E (LS10 + RC + SR) – This application was evaluated on the assumption that an alternative to LS10 related upgrade costs can be obtained for net capitalized costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. In addition, market rates for 10-hour load shifting, regulation control, and spinning reserve are included in the valuation. As shown in Table 11-5, this application yields a NPV of $71 million for an initial investment of about $75.7 million. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 11-13 illustrates the change in NPV over a range of $500 to $1000/kW and shows that PSB systems will compete favorably against alternative solutions over this range. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of XLD -10h modules were increased from $286,000 to $549,000, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $750/kW.

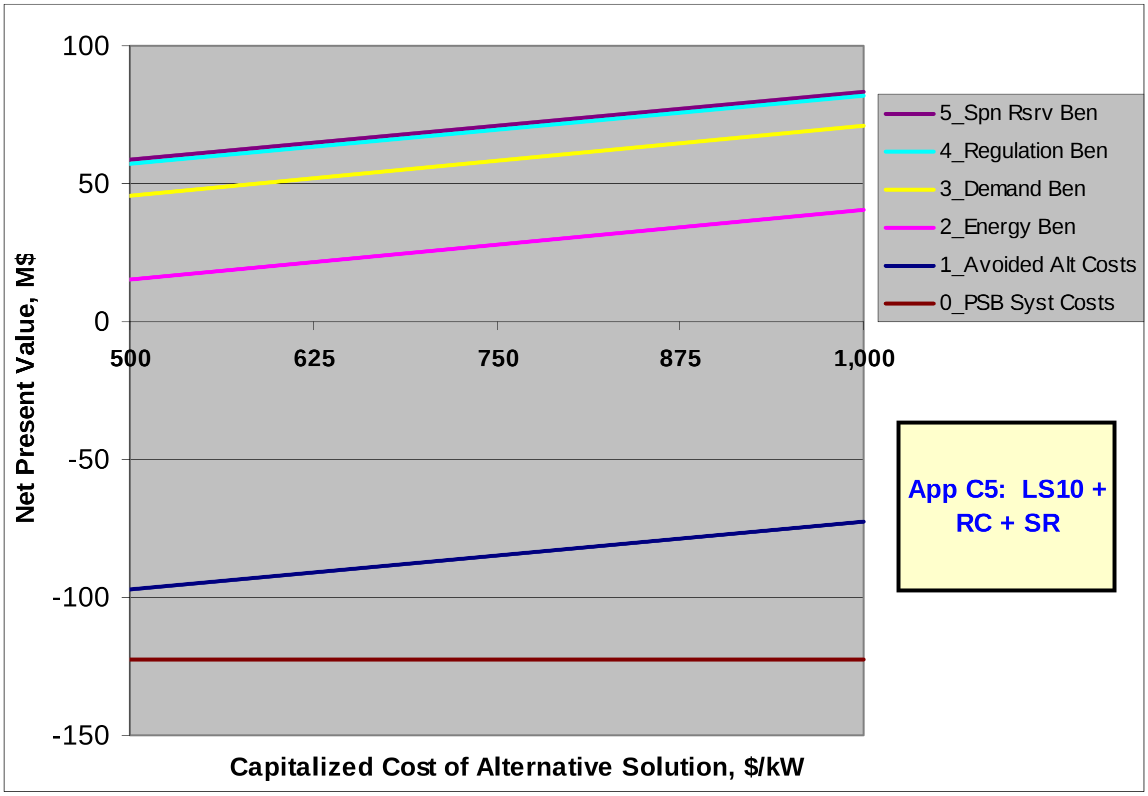

Figure 11-13
Application C5: PSB System NPV vs Cost of Alternative Solution

Interpreting Results From Benefit-Cost Analyses

In general, the PSB battery system is targeting large central plants with nominal power ratings of 50 MW_{ac} and are expected to be most competitive for applications requiring eight or more hours of stored energy.

The reader is reminded that the foregoing analyses are intended as a guide to the initial consideration of energy storage options, and that these analyses are based on representative electric rates and costs for alternative solutions as described in Chapter 4. The assumptions used herein should be reviewed in light of project specific applications, alternative solutions, electric rates and financial parameters.

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12
SUPERCONDUCTING MAGNETIC ENERGY STORAGE

Introduction

Superconducting Magnetic Energy Storage (SMES) exploits advances in materials and power electronics technologies to achieve a novel means of energy storage based on three principles of physics:

- Some materials (superconductors) carry current with no resistive losses.
- Electric currents induce magnetic fields.
- Magnetic fields are a form of energy that can be stored.

The combination of these fundamental principles provides the potential for the highly efficient storage of electrical energy in a superconducting coil. Operationally, SMES is different from other storage technologies in that a continuously circulating current within the superconducting coil produces the stored energy. In addition, the only conversion process in the SMES system is from AC to DC power conversion, i.e., there are none of the thermodynamic losses inherent in the conversion of chemical (battery) and mechanical (flywheel) energy storage to electricity.

SMES was originally proposed [1,2] for large-scale, load leveling, but, because of its rapid discharge capabilities, it has been implemented on electric power systems for pulsed-power and system-stability applications.[18] Figure 12-1 is a picture of the only SMES unit commercially offered at present (American Superconductor's D-SMES). This chapter primarily emphasizes existing SMES applications, but also describes some of the extensive design and development programs for large-scale SMES plants that were conducted in the recent past. Figure 12-2 shows such a plant that is rated at 500 MW_{ac} [3] and stores sufficient energy to deliver this power for 6 to 8 hours. The coil shown is about 1000 meters in diameter and is located at sufficient depth below grade for the surrounding soil to support the magnetic loads from the coil.

[18] A bibliography listing major reports relevant SMES development is included at the end of this chapter.

Figure 12-1
A Trailer Mounted D-SMES Unit With 3MW and Up to 16 MVA Capacities (Picture Supplied by American Superconductor)

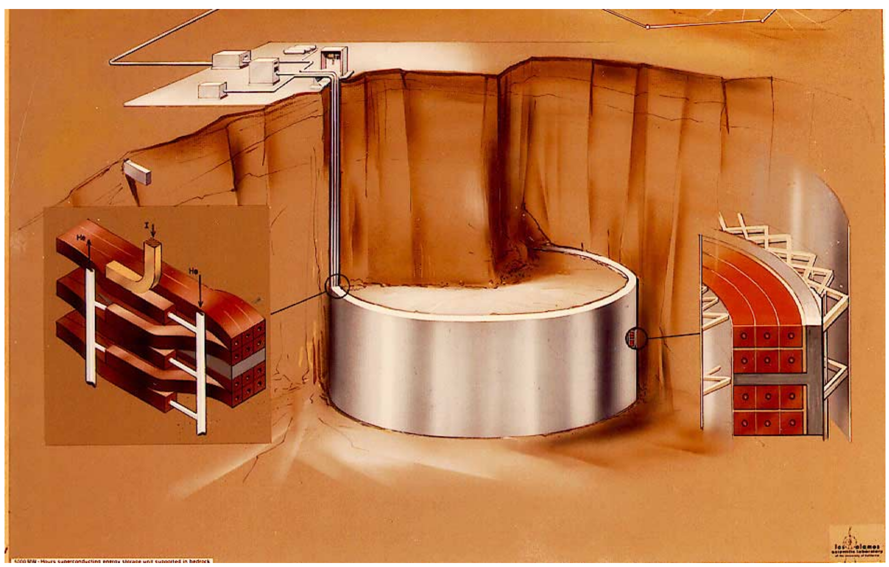


Figure 12-2
Artist Concept of a Large-Scale Diurnal SMES System Constructed Underground

Description

System Components

The power and stored energy in a SMES system are determined by application and site-specific requirements. Once these values are set, a system can be designed with adequate margin to provide the required energy on demand. As illustrated by the SMES systems shown and, SMES units have been proposed over a wide range of power (1 to 1000 MW_{ac}) and energy storage ratings (0.3 kWh to 1000 MWh). Independent of size, all SMES systems include a superconducting coil, a refrigerator, a power conversion system (PCS), and a control system as shown in Figure 12-3. Each of these components is discussed in this section.

The Coil and The Superconductor

The superconducting coil, the heart of the SMES system, stores energy in the magnetic field generated by a circulating current. Since the coil is an inductor, the stored energy is proportional to the square of the current, as described by the familiar equation:

$$E = \frac{1}{2} L I^2, \qquad \textbf{Eq. 12-1}$$

Where L is the inductance of the coil, I is the current, and E is the stored energy.

The total stored energy, or the level of charge, can be found from the above equation and the current in the coil. The maximum practical stored energy, however, is determined by two factors.

- The size and geometry of the coil, which determine the inductance.

The characteristics of the conductor, which determine the maximum current. Superconductors carry substantial currents in high magnetic fields. For example, at 5 Tesla, which is 100,000 times greater than the earth's field, practical superconductors can carry currents of 300,000 A/cm^2.

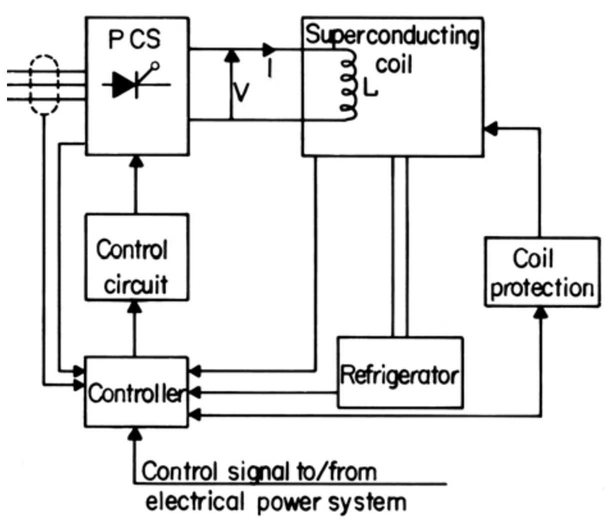
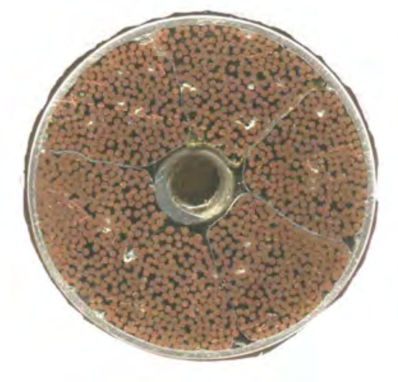


Figure 12-3
Simplified Block Diagram of a SMES System Showing Major Components

All practical SMES systems installed to date use a superconducting alloy of niobium and titanium (Nb-Ti), which requires operation at temperatures near the boiling point of liquid helium, about 4.2 K (-269C or -452°F) which is 4.2 degrees centigrade above absolute zero. Typical conductors made of this material are shown in Figure 12-4.

a



b

Figure 12-4
Typical Conductors Made of the Superconductor Nb-Ti (LBNL & LLNL)

Figure 12-4a, on the left, is a flattened cable made of 30 composite strands wrapped in an insulator made of Kapton and epoxy-fiberglass. Each strand is 0.7 mm in diameter and contains several thousand, 6 µm diameter Nb-Ti filaments extruded in a copper matrix. Figure 12-4b, on the right, is a CICC cable made of several hundred of these strands in a stainless steel conduit. During operation, helium is in direct contact with the superconducting strands and, in the CICC shown, the helium flows through the central tube. Lawrence Berkeley National Lab (LBNL) and Lawrence Livermore National Lab (LLNL) supplied figures 4a and 4b, respectively.

Many tons of Nb-Ti alloy are fabricated worldwide each year for applications such as magnetic resonance imaging (MRI) magnets and accelerators for nuclear physics research. In addition, the aerospace industry uses considerably more of a slightly different Nb-Ti alloy each year for rivets that hold the aluminum skin in place on the bodies and wings of most commercial and military aircraft. Some "research grade" SMES coils use high-temperature superconductors (HTS). However, the state of development of these materials today is such that they are not cost effective for utility-application SMES. An evaluation HTS for SMES was made for EPRI in 1998 [4].

Since the superconductor is one of the major costs of a superconducting coil, one design goal is to store the maximum amount of energy per quantity of superconductor. Many factors contribute to achieving this goal. One fundamental aspect, however, is to select a coil design that most effectively uses the material. This is generally accomplished by a solenoidal configuration, as in the two SMES installations shown in Figure 12-5 and Figure 12-6. Figure 12-5 shows the 30 MJ [5] superconducting coil developed by the Los

Alamos National Laboratory (LANL) and installed by the Bonneville Power Administration at the Tacoma substation. Figure 12-6 is a small, 1 MJ SMES coil.

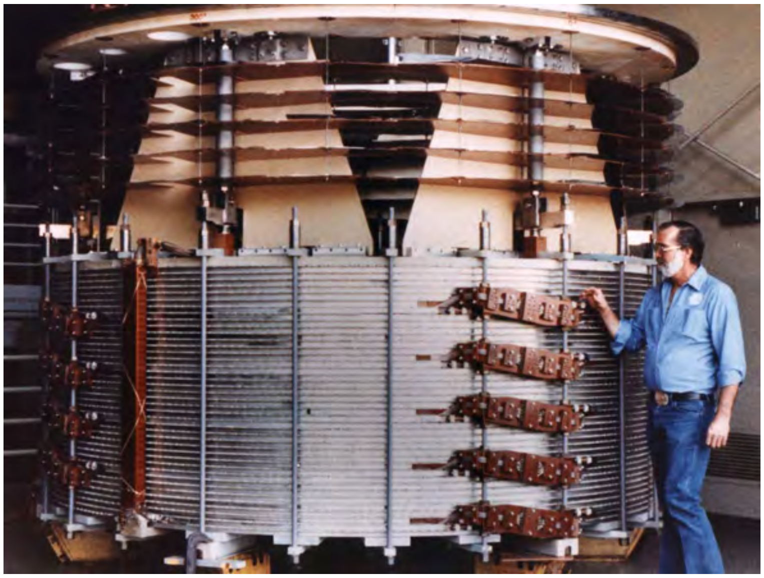


Figure 12-5
30 MJ Superconducting Coil Developed by the Los Alamos National Laboratory (LANL)

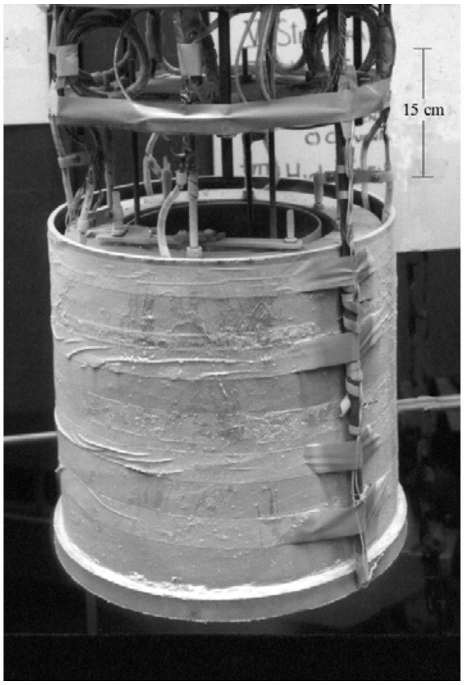


Figure 12-6
1 MJ SMES Coil in a Liquid Helium Vessel (LANL)

Since only a few SMES coils have been constructed and installed, there is little experience with a generic design. This is true even for the small or micro-SMES units for power-quality applications, where several different coil designs have been used.

A primary consideration in the design of a SMES coil is the maximum allowable current in the conductor. It depends on: conductor size, the superconducting materials used, the resulting magnetic field, and the operating temperature. The magnetic forces can be significant in large coils and must be reacted by a containment structure within or around the coil. The coil shown in Figure 12-5 has stainless straps within the cabled conductor for this purpose. The baffle structure at the top of the coil limits gas circulation and maintains a temperature gradient from the liquid helium bath around the coil to the ambient-temperature top plate. Another factor in coil design is the withstand voltage, which can range from 10 kV to 100 kV.

Cryogenic Refrigerator

The superconducting SMES coil must be maintained at a temperature sufficiently low to sustain a superconducting state in the wires. For commercial SMES today, this temperature is about 4.5 K (-269°C, or -452°F). This thermal operating regime is maintained by a special cryogenic refrigerator [6] that uses helium as the refrigerant. Helium must be used as the so-called "working fluid" in such a refrigerator because it is the only material that is not a solid at these temperatures. Just as a conventional refrigerator requires power to operate, electricity is used to power the cryogenic refrigerator. Thermodynamic analyses have shown that power required to remove heat from the coil increases with decreasing temperature. Including inefficiencies within the refrigerator itself, between 200 and 1000 watts of electric power are required for each watt that must be removed from the 4.5 K environment. As a result, design of SMES and other cryogenic systems places a high priority on reducing losses within the superconducting coils and minimizing the flow of heat into the cold environment.

Both the power requirements and the physical dimensions of the refrigerator depend on the amount of heat that must be removed from the superconducting coil. The refrigerator consists of one or more compressors for gaseous helium and a vacuum enclosure called a “cold-box”, which receives the compressed, ambient-temperature helium gas and produces liquid helium for cooling the coil. The 30 MJ coil shown in Figure 12-5 required a dedicated refrigerator that occupied two small trailers, one for the compressor and one for the “cold box”. The coil was tested at 4.5 K and then removed from the cryostat while still cold, which leads to the ice on the surface of the helium vessel. The coil is approximately the size of early power quality SMES coils, such as those fabricated by American Superconductor Inc. and Intermagnetics General Corporation.

Small SMES coils and modern MRI magnets are designed to have such low losses that very small refrigerators are adequate. Figure 12-7 and Figure 12-8 show cryogenic refrigerators of different capacities. In Figure 12-7, a small cryogenic refrigerator (the 30 cm section) and a cold-finger extension that would be appropriate for recondensing liquid helium to cool a superconducting coil are shown. This refrigerator can remove about 5 W at 4.5 K, which is the heat load that might be expected in a micro-SMES for power-quality applications. Such refrigerators usually operate with the cold finger pointing downward but other orientations are possible. Figure 12-8 shows a large liquid helium refrigerator at the Japanese Atomic Energy Research Institute (JAERI). Such a refrigerator would be appropriate for the diurnal SMES installation shown in. It can remove about 10 kW of heat from a large magnet operating at 4.5 K.

Power Conversion System

Charging and discharging a SMES coil is different from that of other storage technologies. The coil carries a current at any state of charge. Since the current always flows in one direction, the power conversion system (PCS) must produce a positive voltage across the coil when energy is to be stored, which causes the current to increase. Similarly, for discharge, the electronics in the PCS are adjusted to make it appear as a load across the coil. This produces a negative voltage causing the coil to discharge. The product of this applied voltage and the instantaneous current determines the power.

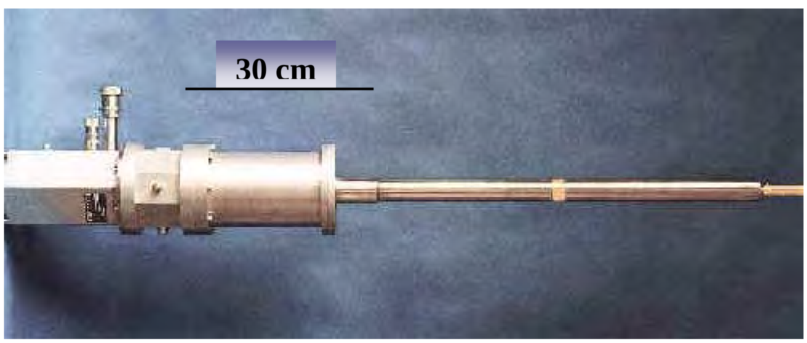


Figure 12-7
Small Cryogenic Refrigerator and Cold-Finger Extension (Cryomech Inc.)

Figure 12-8
Large Liquid Helium Refrigerator (JAERI)

SMES manufacturers design their systems so that both the coil current and the allowable voltage include safety and performance margins. Thus, the PCS power capacity typically determines the rated capacity of the SMES unit. In particular, as energy is removed from the coil, the current decreases. As a result, the PCS must be designed to deliver rated power at the lowest operational coil current, which is about half of the maximum current. Equivalently, about a quarter of the stored energy remains in the coil at the end of a typical discharge.

The PCS provides an interface between the stored energy (related to the direct current in the coil) and the AC power grid. Several different designs have been suggested for the PCS, depending on the application and the design of the SMES coil. The power that can be delivered by the SMES plant depends on the charge status (the current I) and the voltage capability of the PCS, which must be compatible with the grid.

Control System

The control system establishes a link between power demands from the grid and power flow to and from the SMES coil. It receives dispatch signals from the power grid and status information from the SMES coil. The integration of the dispatch request and charge level determines the response of the SMES unit. The control system also measures the condition of the SMES coil, the refrigerator, and other equipment. It maintains system safety and sends system status information to the operator. SMES systems provide remote observation and control via internet connections.

Technology Attributes

Power Rating

The power of a SMES system is established to meet the requirements of the application, e.g., power quality or power system stability. In general, the maximum power is the smaller of two quantities the PCS power rating and the product of the peak coil current and the maximum coil withstand voltage.

The power rating of commercial micro-SMES installations range from 1 to 3 MW_{ac} as discussed in the next section. A much larger unit is now being installed by the Center for Advanced Power Systems (CAPS) at the National High Magnetic Field Laboratory (NHMFL) in Tallahassee, Florida. The PCS for this coil will initially have an installed capacity of 5 MW with planned future enhancement to 25 MW_{ac}. The superconducting coil, however, was designed to deliver 100 MW_{dc}, i.e., the product of the design current and design voltage is 100 MW_{dc}.

Energy Storage Rating

The micro-SMES plants listed above deliver 3 to 6 MJ (0.8 to 1.6 kWh, roughly equivalent to the capacity of a 12 volt, 100 Ah lead acid battery). Because the power rating of these units is so high, this entire quantity of energy can be delivered (i.e., the coil can be fully discharged) in a second or so. The larger, 100 MW_{dc} coil to be installed at NHMFL, mentioned above, was originally designed for a one-second discharge in conjunction with the unified power flow controller (UPFC) operated by American Electric Power (AEP) at its Inez Substation. This coil thus stores about 100 MJ (28 kWh). When the converter at NHMFL is upgraded to 25 MW_{ac}, the coil will be discharged in about 4 seconds.

Physical Dimensions of the SMES Installation

The physical size of a SMES system is the combined sizes of the coil, the refrigerator and the PCS. Each of these depends on a variety of factors. The coil mounted in a cryostat is often one of the smaller elements. A 3 MJ micro-SMES system (coil, PCS, refrigerator and all auxiliary equipment) is completely contained in a 40-ft trailer.

Efficiency

The overall efficiency of a SMES plant depends on many factors. In principle, it can be as high as 95 % in very large systems. For small power quality systems, on the other hand, the overall system efficiency is less. Fortunately, in these applications, efficiency is usually not a significant economic driver. The SMES coil stores energy with absolutely no loss while the current is constant. There are, however, some losses associated with changing current during charging and discharging, and the resulting change in magnetic field. In general, these losses, which are referred to as eddy current and hysteresis losses, are also small.

Unfortunately, other parts of the SMES system may not be as efficient as the coil itself. In particular, there are two potentially significant, continuous energy losses, which are application specific:

- The first is associated with the way SMES systems store the energy. The current in the coil must be flow continuously, and it circulates through the PCS. Both the interconnecting conductors and the silicon-based components of the PCS are resistive. Thus, there are continuous resistive losses in the PCS. This is different from batteries, for example, where there is current in the PCS only during charge and discharge.
- The second is the energy that is needed to operate the refrigerator that removes the heat that flows to the coil from room temperature via: a) conduction along the mechanical supports, b) radiation through the vacuum containment vessel, and c) along the current leads that extend from ambient temperature to the coil operating temperature.

The overall efficiency of a SMES plant depends on many factors. Diurnal (load-leveling) SMES plants designed 20 years ago were estimated to have efficiencies of 90 to 92%. Power quality and system stability applications do not require high efficiency because the cost of maintenance power is much less than the potential losses to the user due to a power outage. Developers rarely quote efficiencies for such systems, although refrigeration requirements are usually specified. A 3 MJ/3 MW_{ac} micro-SMES system, for example, requires about 13 kW of continuous refrigeration power.

Status of SMES Deployment

D-SMES

Today the only commercial SMES product is the D-SMES unit produced by American Superconductor. The individual, trailer-mounted D-SMES units consist of a magnet that contains 3 MJ of stored energy (see Figure 12-1). They can deliver 3 MW for about 1 second and 8 MVAR continuously at 480 V_{ac}. This is accomplished by a PCS that has full 4-quadrant control and uses IGBT based inverters. There is an instantaneous overload capability of 2.3 times continuous (2.3x) for reactive power in the inverter so that the dynamic reactive output can be as high as 18.4 MVAR for up to 1 second. Three networked systems with a total of 9 units have been installed, as indicated in Table 12-1. An additional unit has been ordered.

Table 12-1
Installed D-SMES Units

Start of Operation	Host	Location	Application
June 2000	Wisconsin Public Service	Northern Wisconsin	Transmission Loop Voltage Stability - 6 Units, installed at distributed locations
July 2000	Alliant Energy	Reedsburg, Wisconsin	Transmission Voltage Stability
May 2002	Entergy	North Texas	Voltage Stability - 2 Units

Micro-SMES

Prior to the development of the D-SMES concept, American Superconductor supplied several small power quality SMES units, which are still operational. Designated "Micro"-SMES, these units have been installed around the world in mostly industrial settings to control voltage sag problems on the electrical grid. These are listed in Table 12-2..

SMES Test and Evaluations

In 1992, the Defense Advanced Research Projects Agency (DARPA) issued a request for proposals to build an intermediate sized SMES system for a utility application. There was some consideration/discussion of dual use [7] with a military pulsed power application. As finally released, there was no requirement for a military application as part of the design. A contract was awarded to Babcock and Wilcox (B&W) to build and then install a 0.5 MWh, 20 MW_{ac} plant in Anchorage, Alaska. However, a variety of factors resulted in several changes in direction of the program. It eventually evolved into a program for BWX Technologies to build a 100 MJ (0.028 MWh) coil for the National High Magnetic Field Laboratory (NHMFL) in Tallahassee, Florida. This coil is expected to be completed in 2003 and will be installed at the Center for Advanced Power Systems (CAPS), a part of NHMFL and Florida State University. The coil will be initially operated with a 5 MW_{ac} converter, which is appropriate for the local power system. It is designed, however, to accommodate power flows of up to 100 MW_{ac}.

Table 12-2
Existing Installations of Micro-SMES

Start of Operation	Customer	Location	Application	Power (Voltage)	Energy, MJ
May 1992	Central Hudson G&E	Fishkill, NY	Semiconductor Testing Facility	500 kVA (480 V_{ac})	1.0
December 1993	Tyndall AFB	Panama City, FL	Five General Military Buildings	500 kVA (480 V_{ac})	1.0
March 1993	CYANCO	Winnemuca, NV	400 HP/4160V Motor at Chemical Plant	500 kVA (4160 V_{ac})	1.0(+)
May 1995	Brookhaven National Laboratory	Upton, NY	Light Source Research Center Ultra-violet Light source, ring, and experiment station	1.4 MVA (480 V_{ac})	2.8
May 1995	McClellan AFB	Sacramento, CA	Semiconductor Chip Mfg. Lab Fiber Optic Mfg. Facility Removed when Base Closed	750 kVA (480 V_{ac})	2.8
July 1996	U.S. Air Force	Tinker AFB, OK	DC Link Support for two 800 kW/1000kVA Ups	1.0 MVA (560 V_{ac})	2.8
June 1997	U.S. Air Force	Tinker AFB, OK	DC Link Support for two 800 kW/1000kVA UPS	1.0 MVA (560 V_{ac})	2.8
April 1997	SAPPI - Stanger	Stanger, South Africa	1000 kVA Paper Machine	1.0 MVA (400 V_{ac})	3.0
May 1997	AmeriMark Plastics	Fairbluff, NC	Plastic Extrusion Plant Removed when plant sold	1.4 MVA (480 V_{ac})	3.0
May 1999	STEWEAG	Gleisdorf, Austria	Automotive Parts Foundry	1.4 MVA (480 V_{ac})	3.0
June 2002	Edison/STM	Agrate, Italy	Semiconductor Processing Facility Voltage Sags - 2 Units	8.0 MVA (480 V_{ac})	3.0
April 2002	EDF	Paris, France	Voltage Sag Protection	8.0 MVA (400 V_{ac})	3.0

SMES Deployment Status

Table 12-3 summarizes the status of SMES deployment.

Table 12-3
Technology Status of SMES

Application	MicroSMES for Power Quality	D-SMES for System Stability
Status	Commercial: several units installed as described in Table 12-1	Demonstration
Funding organizations	Private funding in US. Some government funding of potential applications by Japan and Germany	American Superconductor, Wisconsin Power System
Vendors	American Superconductor	American Superconductor
Major demonstrations	See Table 12-2	Northern Wisconsin power system
Lessons learned	Critical issues in terms of the power output and response time.	Early data indicates that D-SMES is effective in the Wisconsin application. Additional information is required on these and other installations.
Major development trends	American Superconductor has several units in the field at this time. However, they have standardized on the D-SMES installation as the standard product. At present there is only one vendor.	American Superconductor is prepared to deliver additional units and is actively searching for customers
Unresolved issues	Costs of SMES units relative to other PQ technologies.	Cost effectiveness of this application compared to other solutions.

Developmental Costs

The original development of SMES systems was for load leveling as an alternative to pumped hydroelectric storage. Thus, large energy storage systems were considered initially. Research and then significant development were carried out over a quarter century in the US, beginning in the early 1970s. This effort was mainly supported by the Department of Defense, the Department of Energy, and EPRI. Internationally, Japan had a significant program for about 20 years, and several European countries participated at a modest level. The Defense Department -sponsored Engineering Test Model (ETM) program funded $72 M worth of design, engineering and test work between 1988 and 1994. In addition, the total international R&D related labor on SMES for load leveling up to the present is estimated to be about 500 person years, or about $75M. Since no practical devices have been constructed or installed, material and construction costs will not increase this value significantly.

At several points during the SMES development process, researchers recognized that the rapid discharge potential of SMES, together with the relatively high energy related (coil) costs for bulk storage, made smaller systems more attractive and that significantly reducing the storage time would increase the economic viability of the technology. Thus, there has also been considerable development on SMES for pulsed power systems. Though EPRI and government organizations have supported some of this effort, a great deal has been internally supported by industry. The total labor R&D in this area has been about 250 person years. In addition, several devices have been fabricated. We estimate that the combined international effort is on the order of $50M for SMES systems for pulsed power, system stability, and for other rapid discharge applications.

T&D System Energy Storage Applications

Select Applications for SMES Systems

This section presents the select applications for which the SMES is suited and describes the key features of the SMES systems when configured to meet the requirements of those applications. Screening economic analyses have shown that SMES systems are potentially competitive for three of the single function applications described in detail in Chapter 3. The following list briefly summarizes and reiterates key requirements for all applications. Those for which SMES is best suited are enclosed by borders.

Single Function Applications

Application A: Grid Angular Stability (GAS) – mitigation of power oscillations by injection and absorption of real power at periods of 1 to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 20 oscillatory cycles, cumulatively equivalent to a full power discharge (FPD) of 1-second duration; 1 event per day; 10 events per year. Valued at the cost of alternative solutions.

Application B: Grid Voltage Stability (GVS) – mitigation of degraded voltage by additional reactive power plus injection of real power for durations up to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 1 second FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application C: Grid Frequency Excursion Suppression (GFS) – "prompt" spinning reserve (or load) for mitigating load-generation imbalance. Requires energy storage to discharge real power for durations up to 30 minutes. The reference duty cycle for analysis is standby for infrequent events characterized by 15-minute FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application D: Regulation Control (RC) – system frequency regulation in concert with load following. The reference duty cycle for analysis is characterized by continuous cycles equivalent to 7.5-minute FPD and charge cycle (triangular waveform), 2 cycles per hour deployed with 10 minutes advance notice. Valued at market rates.

Application E: Spinning Reserve (SR) – reserve power for at least 2 hours with 10 minute notice. The reference duty cycle for analysis is standby for infrequent events characterized by 2-hour FPD, 1 event per day, 10 events per year. Valued at market rates.

Application F: Short Duration Power Quality (SPQ) – capability to mitigate voltage sags (e.g., recloser events). The reference duty cycle for analysis is standby for infrequent events characterized by 5 seconds

FPD, 1 event per hour, 5 events per day, 100 events per year. Valued at the cost of alternative solutions.

Application G: Long Duration Power Quality (LPQ) – SPQ, plus capability to provide several hours reserve power. The reference duty cycle for analysis is standby for infrequent events characterized by SPQ plus standby for 4 hours FPD, 1 event per year. Valued at the cost of alternative solutions.

Application H: 3-hr Load Shifting (LS3) – shifting 3 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 3-hour FPD, 1 event per day, 60 events per year. Valued at market rates.

Application I: 10-hr Load Shifting (LS10) – shifting 10 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 10-hour FPD, 1 event per day, 250 events per year. Valued at market rates.

Combined Function Applications (In the Order Noted)

Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC)

Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR)

Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR)

Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR)

Application C5: Combined Applications I, D, E (LS10 + RC + SR)

SMES System Compliance With Application Requirements

The SMES product performance parameters discussed in the previous section were used to develop approximate sizes and operational parameters for systems meeting the requirements of the applications selected for SMES in the previous section. The key factors in sizing SMES systems are the power and energy requirements of the application. The D-SMES product line can be adapted for increased DC-link voltages and increased discharge durations, and two different configurations have been adapted for the three applications noted above. Performance aspects of SMES systems for the selected applications are described below and summarized in Table 12-4. The reference power for all applications in 10 MW_{ac}.

- Application A: Grid Angular Stability (GAS) – This application requires that the system continuously detect and mitigate infrequent short duration, oscillatory events. D-SMES, adapted to 3000 V_{dc} chopper voltage, was equipped with a Type I PCS and configured for this application to be capable of full power discharges for up to 1 second. The system will spend virtually its entire life in standby mode, for which standby SMES efficiency is calculated at 99.4%, attributed to continuous power for refrigeration and coil current losses at the PCS interface. The net system standby efficiency, including PCS losses, is 97.4%, and the projected life for this application is 20 years.

- Application B: Grid Voltage Stability (GVS) – This application requires that the system continuously detect and mitigate infrequent voltage instabilities and provide short duration real power, as well as continuous reactive power. D-SMES, adapted to 3000 V_{dc} chopper voltage, was equipped with a Type I PCS and configured for this application to be capable of real power discharges for up to 1 second, as well as to provide reactive power. The system will spend virtually its entire life in standby mode, for which standby SMES efficiency is calculated at 99.4%, attributed to continuous power for refrigeration and coil current losses at the PCS interface. The net system standby efficiency, including PCS losses, is 97.4%, and the projected life for this application is 20 years.

- Application F: Short Duration Power Quality (SPQ) – This application requires that the system continuously detect and mitigate infrequent PQ events lasting to up to 2 seconds. D-SMES, capable of full power discharges for up to 2 seconds, was equipped with a Type III PCS, based on 750Vdc chopper voltage (pulse factor of 5) suitable for discontinuous IGBT converters. This system will also spend virtually its entire life in standby mode, for which standby SMES efficiency is calculated at 98.3%, attributed to continuous power for refrigeration and coil current losses at the PCS interface. The net system standby efficiency, including PCS losses, is 96.3%, and the projected life for this application is 20 years.

Table 12-4
SMES System Compliance With Application Requirements

Applications	Single Function		
	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	**App B: GVS -- 1 sec FPD per cycle, 10 events/yr, 1 event/d**	**App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr**
Model Selection			
Type	DSMES-3KV	DSMES-3KV	DSMES-480V
Pulse Factor	NA	NA	5.0
Chopper Voltage (V_{min})	3,000	3,000	750
Maximum DOD, %	100%	100%	100%
Replacement Interval, yr	20	20	20
PCS Selection			
PCS Type (Chapter 5)	I	I	III
Duty Cycles			
Grid Support or Power Quality (GS or PQ)			
Power, MW	10	10	10
Event Duration, sec	1.0	1.0	2.0
Summary System Data			
Standby Hours per Year	8,760	8,760	8,760
System Net Efficiency, % (See Note)	97.4%	97.4%	96.3%
SMES Standby Efficiency, %	99.4%	99.4%	98.3%
PCS Standby Efficiency, %	98.0%	98.0%	98.0%
System Footprint, MW/sqft (MW/m^2)	0.0051 (0.055)	0.0051 (0.055)	0.0044 (0.047)
SMES Footprint, MW/sqft (MW/m^2)	0.015 (0.16)	0.015 (0.16)	0.01 (0.11)

Note: System net efficiency includes losses for energy conversion and system standby expressed on an annual basis, i.e., one minus inefficiency, where inefficiency equals the ratio of annual energy losses to the product of system rated power times 8760 hours, expressed in percent.

Benefit and Cost Analyses

SMES System Pricing and Integrated System Costs

American Superconductor has adapted product lines in response to market forces over the past few years, which saw a rapid rise in demand for power quality equipment in the late 1990's, and subsequent abrupt decline more recently. During this period, demand for utility grid support systems has been constrained to local congestion issues. In response to this market, American Superconductor has brought forth the D-VAR product line, which focuses on demand for reactive power products. D-SMES based products remain an important element of their product portfolio.

For the Handbook's reference deployment date of 2006 and rating of $10MW_{ac}$, nominal unit prices supplied by American Superconductor [4] for 3 MW_{ac}, 3 MJ D-SMES products have been applied to the 10 MW_{ac} GAS and GVS (10 MJ, DSMES-3KV) and SPQ (20 MJ, DSMES-480V) applications. [19] No replacement modules are projected over the 20-year project lifetimes. The resultant SMES prices for GAS, GVS and SPQ applications used in the benefit-cost assessments herein are:

SMES Unit	2006 Prices, K$
DSMES-3KV	$2030
DSMES-480V	$3030

The scope of supply corresponding to the above units includes refrigeration and refrigeration power supply, the magnet (coil) and magnet control system, and the DC-chopper (magnet interface to the inverter), plus technical support for system integration, installation and startup.

The cost of integrated systems is obtained by combining the cost of the SMES scope of supply with the appropriate PCS and BOP costs as described in Chapter 5. The PCS and BOP costs shown in Table 12-5 are based on the methodology described in Chapter 5. SMES systems for the GAS and GVS applications use Type I PCS as a result of relative high (3000 V_{dc}) DC-link voltage, while the system for SPQ uses a Type III "discontinuous" IGBT-based PCS. Since the cost of exterior enclosures is included in the SMES scope of supply, the cost of exterior space is included at $20 per square foot. SMES disposal costs are assumed to be negligible since no hazardous materials are involved. In accordance with the provisions of Chapter 5, BOP costs are assigned at $50/kW because SMES is commercially available as a fully integrated system.

[19] The designations DSMES-3KV and DSMES-480V are used for the purposes of describing adaptations used in this Handbook and are not American Superconductor designations.

Fixed O&M costs for the PCS are based on $2/kW as required by provisions in Chapter 5, and SMES maintenance is projected at $5/kJ. Representative maintenance activities include:

- Servicing refrigeration equipment
- Confirming the operability of system protective devices
- Calibrating sensors and instrumentation
- Inspecting for unusual vibrations, noise or odors
- Inspecting for abnormal conditions of connecting cables and piping
- Inspecting insulation resistance

No disposal costs are included since all materials can be treated as industrial waste.

Table 12-5
Capital and Operating Costs for SMES Systems

Applications	Single Function		
	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	**App B: GVS -- 1 sec FPD per cycle, 10 events/yr, 1 event/d**	**App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr**
SMES Capacity, MWhac	0.003	0.003	0.006
PCS Initial Cost, $/kW	120	120	150
BOP Initial Cost, $/kW	50	50	50
SMES Initial Cost $/kW	207	207	309
SMES Initial Cost $/kWh	740,000	740,000	560,000
Total Capital Cost, M$	3.8	3.8	5.1
O&M Cost – Fixed, $/kW-year	14.5	14.5	22.2
O&M Cost– Variable, $/kW-year	8.7	8.7	12.4
NPV SMES Disposal Cost, $/kW	0.0	0.0	0.0

Note: The total initial cost may be calculated in two ways:
1. By mutiplying the sum of PCS, BOP and Battery initial costs expressed in $/kW by the reference power,
2. OR by mutiplying the sum of PCS and BOP expressed in $/kW by the reference power and then adding the product of Battery Initial cost expressed in $/kWh and the Battery Capacity

Lifecycle Benefit and Cost Analysis for SMES Systems

Further insight to the value of energy storage can be gained through lifecycle cost analyses using a net present value (NPV) methodology and comparison with alternatives. For the convenience of the reader, the financial parameters and electric rate structure set forth in Chapters 4 and 5 and used in the analyses are summarized in Table 12-6 and Table 12-7.

Table 12-6
Financial Parameters

Dollar Value	2003
System Startup	June 2006
Project Life, years	20
Discount Rate (before tax), %	7.5
Property Taxes & Insurance, %/year	2
Fixed Charge Rate, %/year	9.81

Table 12-7
Electric Rates

Load Shifting On Peak Period	3	10
Number Cycles per year	60	250
On-Peak Energy, $/MWh	120	80
Off-Peak Energy, $/MWh	20	
Yearly Average Energy Charge, $/MWh	38	
Regulation Control, $MW-Hour (power), $/MWh	16	
Spinning Reserve, $MW-Hour (power), $/MWh	3	
Transmission Demand Charge, $/kW-mo	5	

The results of lifecycle cost benefit analyses of select SMES applications are summarized in Table 12-8 and discussed below. The bases and methodology used in valuing energy storage applications is described in detail in Chapter 4. The details of the cost benefit analysis for each application are discussed below.

Table 12-8
Summary of Benefit and Cost Analyses of SMES Battery Systems

Applications	Single Function		
	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	App B: GVS -- 1 sec FPD per cycle, 10 events/yr, 1 event/d	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr
Alt Solution Value, $/kW	750	500	1,000
Initial Installed Cost, M$	3.76	3.76	5.11
Total Costs, M$	(6.1)	(6.1)	(8.6)
Total Benefits, M$	7.50	5.0	10.0
Benefit to Cost Ratio	1.23	0.82	1.16
NPV, M$	1.4	(1.1)	1.4
SMES Module	DSMES-3KV	DSMES-3KV	DSMES-480V
SMES 2006 Price, ($K, FOB)	2,030	2,030	3,030
SMES Price for NPV=0, ($K, FOB)	3,180	1,100	4,160

- Application A: Grid Angular Stability (GAS) – This application was evaluated on the assumption that an alternative solution capable of mitigating GAS events can be obtained for net capitalized costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 12-8, this application yields a NPV of $1.4 million for an initial investment of about $3.8 million on this basis. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 12-9 illustrates the change in NPV over a range of $500 to $1000/kW and shows that SMES systems will compete favorably against alternative solutions with net capitalized costs in excess of about $610/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of DSMES-3KV were increased from $2.03 to $3.18 million, the NPV would equal zero, i.e., costs and benefits would be equal.

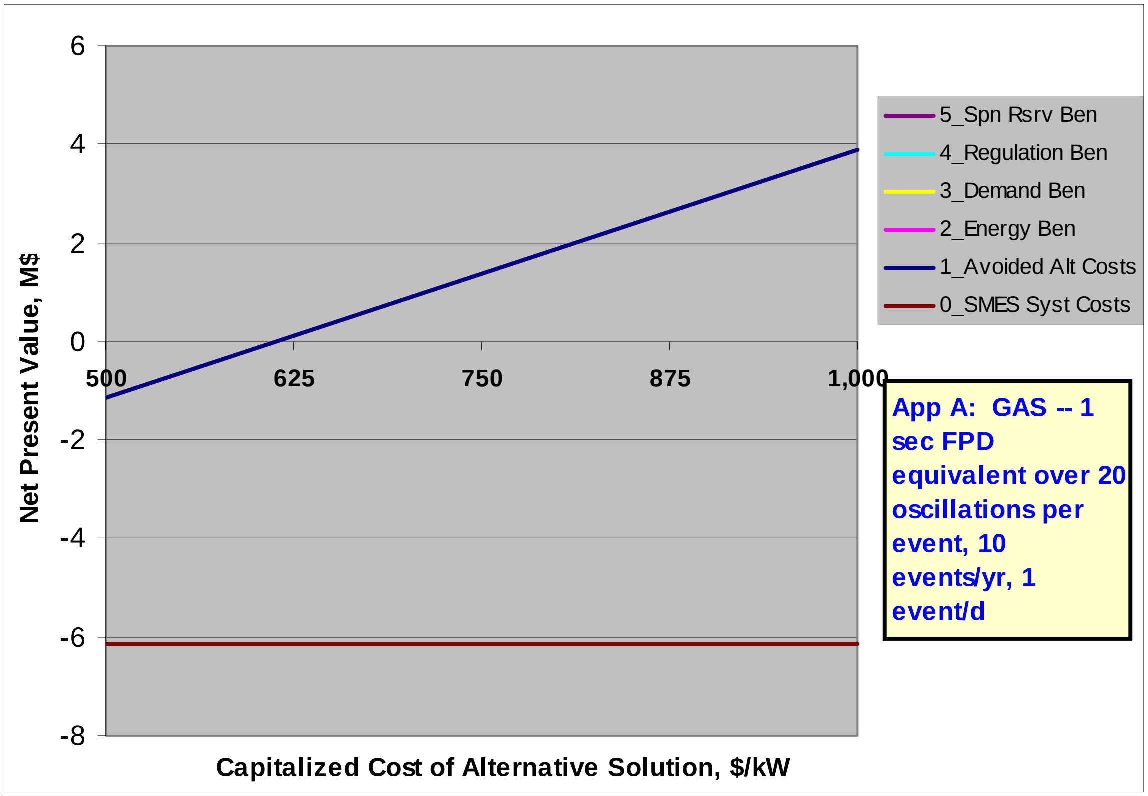


Figure 12-9
Application A: SMES System NPV vs Cost of Alternative Solution

- Application B: Grid Voltage Stability (GVS) – This application was evaluated on the assumption that an alternative solution capable of mitigating GVS events can be obtained for net capitalized costs of about $500/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 12-8, this application yields a negative NPV of ($1.1) million for an initial investment of about $3.8 million on this basis. However, the benefit to cost ratio is about 0.8, and SMES is deemed to be marginally competitive in that it should be considered in circumstances where its intrinsic properties (e.g., its relatively small space requirements) are of high value. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 12-10 illustrates the change in NPV over a range of $250 to $750/kW and shows that SMES systems will compete favorably against alternative solutions with net capitalized costs in excess of about $610/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of DSMES-3KV were decreased from $2.03 to $1.1 million, the NPV would equal zero, i.e., costs and benefits would be equal.

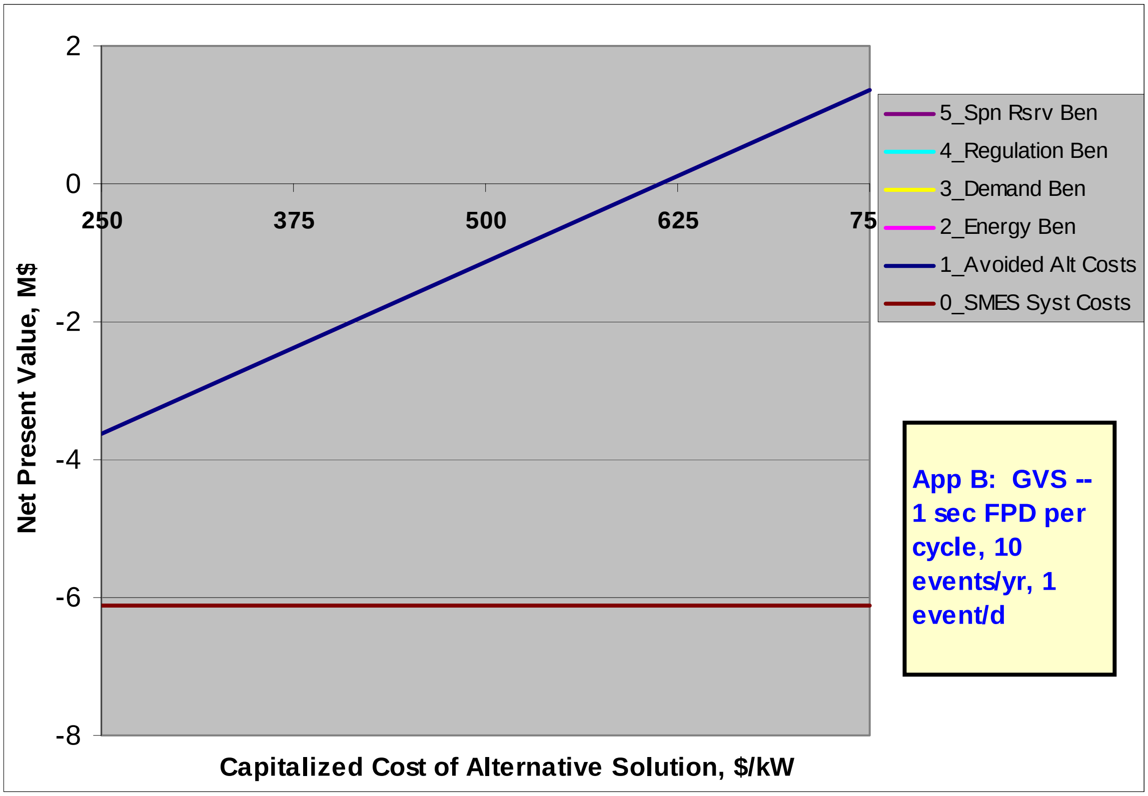


Figure 12-10
Application B: SMES System NPV vs Cost of Alternative Solution

- Application F: Short Duration Power Quality (SPQ) – This application was evaluated on the assumption that an alternative solution capable of mitigating SPQ events can be obtained for net capitalized costs of about $1000/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 12-8, this application yields a NPV of $1.4 million for an initial investment of about $5.1 million on this basis. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 12-11 illustrates the change in NPV over a range of $500 to $1500/kW and shows that SMES systems will compete favorably against alternative solutions with net capitalized costs in excess of about $860/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of GAS SMES were increased from $3.03 to $4.16 million, the NPV would equal zero, i.e., costs and benefits would be equal.

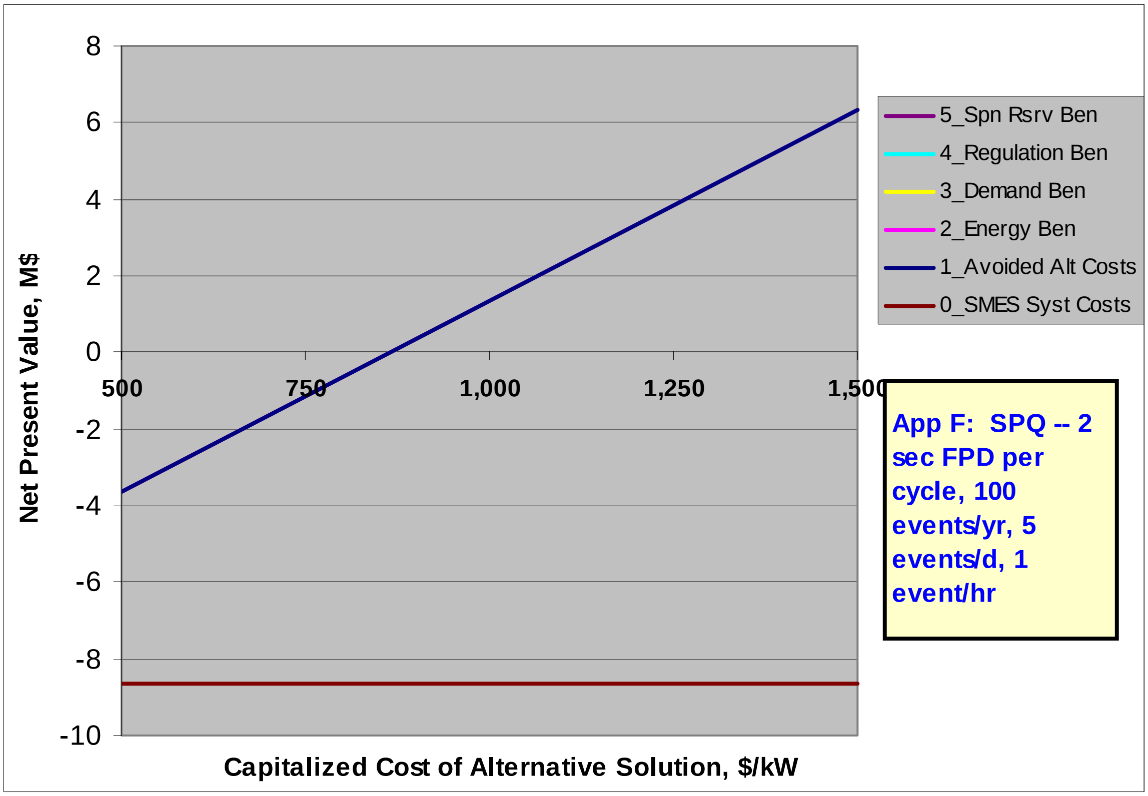


Figure 12-11
Application F: SMES System NPV vs Cost of Alternative Solution

Interpreting Results From Benefit-Cost Analyses

In general, SMES systems are expected to be competitive for grid support applications.

The reader is reminded that the foregoing analyses are intended as a guide to the initial consideration of energy storage options, and that these analyses are based on representative electric rates and costs for alternative solutions as described in Chapter 4. The assumptions used herein should be reviewed in light of project specific applications, alternative solutions, electric rates and financial parameters.

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SMES Bibliography

A series of conferences and journals contain innumerable articles on superconductivity and SMES technology, including:

- The Applied Superconductivity Conference is held in North America every even year. The proceedings of recent conferences are published in the IEEE Transactions on Applied Superconductivity. They contain considerable information on applicable superconducting materials and on SMES technology.
- The Material Research Society meets at least once per year and the proceedings of these meetings contain considerable information on the status of basic research in the area of superconductivity.
- The American Physical Society (APS) has several national and regional meetings each year that include sessions on LTS and HTS materials. In addition, there are several journals published by the American Institute of Physics, of which the APS is a member, that include articles on superconductivity.

Seminal Articles and Books

- The first paper on the phenomenon of superconductivity was:
  H. K. Onnes, Leiden Comm. 120b, 122b, 124c (1911)
- The first paper on high temperature superconductivity was:
  J. G. Bednorz and K. Mueller, Z. Phyzik B64, 189 (1986)

- The accepted book that is used to develop magnet and conductor designs is: Martin N. Wilson, Superconducting Magnets Oxford Science Publications, Oxford, UK, 1983.
- The original article that related stored energy and support structure was: R. Clausius, “On a Mechanical Theorem Applicable to Heat,” Phil. Mag. S-4, Vol. 40, pp 12-127, 1870.

Early Articles and Papers On SMES

Early articles and papers on SMES include the following:

- H. A. Peterson, N. Mohan, and R. W. Boom, "Superconductive Energy Storage Inductor-Convertor Units for Power Systems", IEEE Trans. Power Systems", IEEE Trans. Power App. Syst., Vol. PAS-94, No. 4, July-August 1975.
- W.V. Hassenzahl, "Will Superconducting Magnetic Energy Storage be Used on Electric Utility Systems?" IEEE Transactions on Magnetics, MAG-11, No. 2, 1975, pp. 482-88 (LA-UR-74-1470).
- J.D. Rogers, W.V. Hassenzahl, and R.I. Schermer, "1 GWh Diurnal Load levelling Superconducting Magnetic Energy Storage System Reference Designs," Los Alamos Scientific Laboratory LA- 7885-MS Vols. I-VIII, September 1979.
- William V. Hassenzahl, "Superconducting Magnetic Energy Storage," Proc. of the IEEE, 71 (September 1983), pp. 1089-98.

The first report that considered a diurnal SMES plant for other utility applications (in this case spinning reserve) was:

- W.V. Hassenzahl, B.L. Baker, and W.E. Keller, "The Economics of the Superconducting Magnetic Energy Storage Systems for Load levelling: a Comparison with Other Systems," Los Alamos Scientific Laboratory Report LA-5377-MS, September 1973.

Early reports on the need for energy storage and the use of SMES for system stability include:

- R. L. Cresap, W. A. Mittelstadt, D. N. Scott, and C. W. Taylor, “Operating Experience with Modulation of the Pacific HVDC Intertie”, IEEE PAS Summer Meeting, Mexico City 1977.

EPRI supported a series of studies on SMES in the early 1980’s. In 1986, EPRI decided to pursue the design and construction of an engineering test model ETM that stored about 100 MWh. This model stored about 2 percent of the energy of a full-scale diurnal SMES. At about the same time, the Strategic Defense Initiative (SDI) required a pulsed energy storage system with capacities greater than 1000 MWh and with discharge times of about 30 minutes. Much of the development of the diurnal SMES application over the next 6 years was based on a dual use concept. Several reports and papers related to this effort are given below.

- W. V. Hassenzahl, "Superconducting Magnetic Energy Storage", IEEE Trans. on Magnetics Vol. 24 No.2, March 1989, pp 750-758.
- Hassenzahl, W. V., R. B. Schainker, and T. M. Peterson, "The Superconducting Energy Storage ETM", Modern Power Systems Review, Vol. 11-3, pp 27-31, March 1991, London.

Other Articles In The Design And Use Of SMES

Other articles of interest in the design and use of SMES include:

- Facts with Energy Storage: Conceptual Design Study, EPRI, Palo Alto, CA: 1999. TR-111093
- W. V. Hassenzahl, "Considerations against force compensated coils", IEEE Trans. on Magnetics, Vol. 24 No.2, March 1989, pp 1854-1857.
- J. F. Picard, C. Levillain, P. G. Therond (Electricité de France, R&D division), SCENET, "Advantages and perspectives of SMES", 2nd Workshop on Power Applications of Superconductivity, November 1997.
- C. Levillain, P. G. Thérond (Electricité de France), 'Minimal Performances of High Tc Wires for Cost Effective SMES Compared with Low Tc's", IEEE Transactions on Magnetics, Vol. 32, No. 4, July 1996.
- Micro Superconducting Magnetic Energy Storage (SMES) System For Protection of Critical Industrial and Military Loads, A. K. Kalafala, J. Bascuñan, D. D. Bell, L. Blecher, F. S. Murray, M. B. Parizh, M. W. Sampson, and R. E. Wicox (Intermagnetics General Corporation), IEEE Transactions on Magnetics, Vol. 32, No. 4, July 1996.
- Operation of a Small SMES Power Compensator, K. P. Juengst, H. Salbert (Forschungszentrum Karlsruhe, Institut für Technische Physik), O. Simon (Elektrotechnisches Institut (ETI), Universität Karlsruhe), Proceedings from European Conference on Applied SC, July 1997, Eindoven.

High Temperature Superconductors for SMES

Since their discovery in 1986, high temperature superconductors have been proposed for SMES applications. Some of the papers on the subject are listed here:

- Prospects for the Use of High T_C Materials for Superconducting Magnetic Energy Storage, William V. Hassenzahl, Proceedings of EPRI Workshop on High-Temperature Superconductivity, April 1988, EPRI EL/ER-5894P-SR

- Conceptual Design Study of Superconducting Magnetic Energy Storage Using High Temperature Superconductors, S. M. Schoenung (W. J. Schafer Associates), R. L. Fagaly, M. Heiberger, R. B. Stephens, J. A. Leuer, R. A. Guzman, E. R. Johnson (General Atomics), J. Purcell, L. Creedon, J. R. Hull (Advanced CryoMagnetics), Final Report to DOE February 1993, DOE/CE/34019-1
- Superconducting Magnetic Energy Storage (SMES) Using High-Temperature Superconductors (HTS), Susan M. Schoenung, Robert L. Bieri (W. J. Schafer Associates), Final Report for Sandia National Laboratory May 1994, Subcontract AG-5265
- S. S. Kalsi, D. Aided, B. Connor, G. Snitchler, J. Campbell, R. E. Schwall (American Superconductor Corporation), J. Kellers (American Superconductor Europe), Th. Stephanblome, A. Tromm (Gesellschaft für Innovative Energieumwandlung und Speicherung GmbH), P. Winn (Applied Engineering Technologies), “HTS SMES Magnet Design and Test Results”, IEEE Transactions on Applied Superconductivity, Vol. 7, No. 2, June 1997.
- R. Mikkonen, M. Lahitnen, J. Lehtonen, and J. Paasi (Tampere University of Technology), B. Conner, S. S. Kalsi (American Superconductor), “Design Considerations of a HTS μ-SMES”, European Conference on Applied SC, July 1997

Conference Proceedings

As mentioned earlier, one of the riches sources of information on SMES development are the proceedings of the Applied Superconductivity Conferences. The most recent conference was August 4-9, 2002, and the proceedings will be published by the IEEE in April of 2003. Titles of some of the papers on SMES in this conference are given below.

- A 100 MJ SMES Demonstration at FSU-CAPS, C.A. Luongo, T. Baldwin, FSU-CAPS; C.M. Weber, P. Ribeiro, BWX Technologies.
- Magnet Power Supply with Power Fluctuation Compensating Function Using SMES for High Intensity Synchrotron, T. Ise, Y. Kobayashi, S. Kumagai, Osaka University; H. Sato, T. Shintomi, KEK.
- Impact of Micro-SMES on Power Flow, J. Liu, M.M.A. Salama, R.R. Mansour, University of Waterloo.
- Design of a 150 kJ High-Tc SMES for a 20 kVA Uninterruptible Power Supply System, R. Kreutz, H. Salbert, D. Krischel, A. Hobl, C. Radermacher, ACCEL Instruments GmbH; N. Blacha, AEG SVS GmbH; P. Behrens, EUSGmbH; K. Dütsch, E.ON Netz GmbH.
- Fabrication and Test of a Superconducting Coil for SMES System, H.J. Kim, K.C. Seong, J.W. Cho, S.W. Kim, Y. K. Kwon, Korea Electrotechnology Research Institute.

- Fabrication of a 4kJ High-Tc Superconducting Pulse Coil Wound with a Bi2223 Wire for SMES, H. Hayashi, H. Kimura, Y. Hatabe, K. Tsutsumi, Kyushu Electric Power Co., Inc; M. Iwakuma, K. Funaki, Kyushu University; A. Tomioka, T. Bohno, Y. Yagi, Fuji Electric Co., Ltd.
- A 5 kJ HTS SMES Magnet System with Temperature Variation, X.H. Jiang, Y.C. Lai, Dept. of Electrical Engineering, Tsinghua University; J. Yang, N.Q. Jin, Institute of Electrical Engineering, Chinese Academy of Sciences; Z.G. Cheng, Baoding Tianwei Group Co. Ltd.
- HT-SMES Operating at Liquid Nitrogen Temperatures for Demonstrating Power Conditioning, A. Friedman, N. Shaked, E. Perel, F. Gartzman, M. Sinvani, Y. Wolfus, Y. Yeshurun, Center of Superconductivity, Bar-Ilan University.

Refrigeration Systems

The two articles below show the cost vs. size dependence of the refrigeration systems for superconducting magnets.

- M. A. Green, R. A. Byrns, and S. J. St. Lorant, “Estimating the Cost of Superconducting Magnets and the Refrigerators Needed to Keep Them Cold”. Advances In Cryogenic Engineering, Vol 37, Feb, 1992 Plenum Press, New York.

Coil Geometries

Several different geometries have been considered for SMES. They are described in the report below. In general, the solenoid is simplest to build and is the lowest price. However, other designs might be more effective for specific applications, particularly those where the stray magnetic field is important.

- W. V. Hassenzahl, “A Comparison of the Conductor Requirements for Energy Storage Devices Made with Ideal Coil Geometries”, IEEE Transactions on Magnetics, VOL. 25, No.2 March 1989.

Other Reports on SMES Applications and Benefits

- W.V. Hassenzahl, B.L. Baker, and W.E. Keller, "The Economics of the Superconducting Magnetic Energy Storage Systems for Load levelling: a Comparison with Other Systems," Los Alamos Scientific Laboratory Report LA-5377-MS, September 1973.
- “Reassessment of Superconducting Magnetic Energy Storage (SMES) Transmission System Benefits”, Power Systems Engineers, EPRI Report 1006795, March 2002.
- J. DeSteese, et al “Benefit/Cost Comparisons of SMES in System-Specific Application Scenarios,” Proc. World Congress on Superconductivity, Munich, Germany, September, 1992.

- S. Schoenung, “Superconducting Magnetic Energy Storage Benefits Assessment for Niagara Mohawk Power Corporation,” report prepared for Oak Ridge National Laboratory, DE-AC05-840R21400, 1994.
- Zaininger, SAND98-1904 (SMUD Wind and PV study)
- “The Market Potential for SMES in Electric Utility Applications,” prepared by Arthur D. Little for Oak Ridge National Laboratory, Report No. ORNL/Sub85-SL889/1, 1994.
- S. Schoenung, J. Badin, J. Daley, “Commercial Applications and Development Projects for Superconducting Magnetic Energy Storage,” Proc. of the American Power Conference, Chicago, 1993.

13
FLYWHEEL ENERGY STORAGE

Introduction

Flywheels rank among the earliest mechanical energy storage mechanisms discovered by mankind. The principle was probably first applied in the potter's wheel, a device used to produce symmetrical ceramic containers. The millstone, used to grind grain into flour, is another form of the flywheel [1].

Beginning in the early years of the Industrial Revolution, flywheels found their way into various machines to smooth the delivery of mechanical power. In handlooms, for instance, flywheels were used to store mechanical energy applied in pulses by the operator. Flywheels allowed the development of more complex power machines such as steam engines and internal combustion engines by enabling the delivery of constant, continuous power from a pulsating power source. One of the first application of flywheels to large-scale electric power systems was for smoothing the output of low-speed steam piston engines driving flywheel generators, such as those in Figure 13-1.

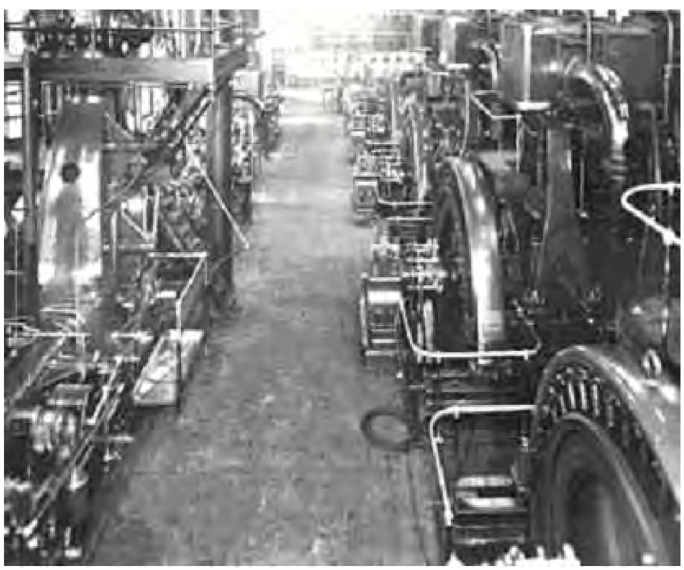

Figure 13-1
Vertical Reciprocating Steam Engines Drive Westinghouse Flywheel Electric Generators in Pittsburgh's Railway Station, From 1902 Until 1950's (Courtesy Of Smithsonian Institute)

Electrical systems continue to use integrated flywheels to improve the smoothness and quality of power output. Waterwheel generators benefit from the flywheel action of large salient-pole rotors. Heavy steel wheels are commonly integrated into electric motor/ generator sets. In the event of pulsating or interrupted propulsion the additional momentum of the flywheels smooths the output and helps to maintain desired operating frequency. This direct flywheel contribution has improved quality and has provided ride-through capability during momentary interruptions lasting less than one second.

The concept of using flywheels as independent energy storage devices came in the 1960s and 1970s. The evolution of efficient inverters and rectifiers meant that frequency could be controlled even when the generator was not spinning inside the desired operating range. This allows the utilization of a higher percentage of a flywheel's momentum, thus delivering more energy and adding time in ride-through applications. With this development, flywheels began to be considered for independent energy storage applications in the transportation and electric utility industries.

The energy crises of the 1970s accelerated development of flywheel technology, bringing to the fore new technologies such as carbon composite rotors and magnetic bearings, which allowed higher energy densities. Development slowed in the 1980s, but utility deregulation and increased public concern over environmental issues revived interest in energy storage technologies in the next decade. The 1990s saw the emergence of a number of small companies dedicated to the commercialization of flywheel energy storage systems. A few larger companies also applied their resources to the technology.

Commercialization efforts continue today. Conservative versions of the technology, using steel wheels at low-rotational speeds, have managed to penetrate the power conditioning market in UPS and power quality applications. More advanced flywheel technologies, however, have not yet found widespread acceptance, due to technical and economic obstacles, both real and perceived.

Description

Energy Storage Capacity

Flywheels store energy in the form of the angular momentum of a spinning mass, called a rotor. The work done to spin the mass is stored in the form of kinetic energy. The amount of kinetic energy stored in a spinning object is a function of its mass and rotational velocity:

$$E = \tfrac{1}{2} I\omega^2$$

Eq. 13-1

In Equation 13-1, E is the kinetic energy, I is the moment of inertia (with units of mass-distance^2), and ω is the rotational velocity (with units of radians/time). The moment of inertia is dependent on the mass and geometry of the spinning object. It can be shown that for a solid disc rotating about its axis, stored kinetic energy is described by the equation:

$$E = \tfrac{1}{4} Mr^2\omega^2 \approx \tfrac{1}{4} Mv^2$$

Eq. 13-2

In Equation 13-2, M is the mass of the disc, r is its radius, and v is the linear velocity of the outer rim of the cylinder (approximated by rω). Equation 13-2 shows that increasing the rim speed is more effective than increasing the mass of the rotor in improving the energy capacity of a flywheel. In practice, however, flywheel design is limited by the strength of the rotor material to withstand the stresses caused by rotation [1].

The variables involved in flywheel design are illustrated in Figure 13-2.

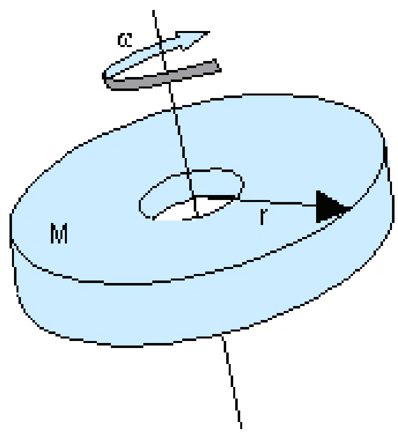

Figure 13-2
Physical Factors in Energy Storage Capacity

Energy Conversion

Flywheels store kinetic energy, while the end-use applications of interest in this Handbook will use electric energy. Conversion from kinetic to electric energy is simply accomplished via electromechanical machines. Many different type machines are being used in available flywheel systems. The key is to match the decreasing speed of the flywheel during discharge and the acceleration when recharged with a fixed frequency electrical system. Along with electromechanical machines, two methods are used to match system frequencies, mechanical clutches and power electronics. The trend is toward a power electronic frequency conversion, with mechanical clutches only seen in the larger low-speed machines.

Friction and Energy Losses

In any real flywheel system, there are forces that act against the spinning wheel, causing it to slow down and lose energy. These forces arise from friction between the rotor and surrounding environment, between the rotor bearing and its support, and from the stresses and strains within the rotor itself. In addition to these energy losses through friction, the minute stress differentials within the spinning rotor and induced magnetic currents in the motor/generator can also cause energy losses.

The mechanical bearings, which support the flywheel rotor, are a significant source of friction. Many developers have introduced magnetic bearings into the flywheel system, which either eliminate or reduce friction on mechanical bearings, reducing frictional losses.

If the rotor is spinning in a fluid such as air, the action of the fluid is also a source of frictional loss. At higher speeds, this loss can be very large. Most developers have addressed this problem by enclosing the rotor within a vacuum or a low-viscosity fluid.

Thermal Effects

The energy lost during rotation is transformed into heat, which raises the temperature of the flywheel rotor. The temperature of the rotor must be kept under the maximum temperature sustainable by its constituent materials. The temperature is managed by reducing the heat generated, and by removing the accumulated heat from the system.

Low-loss bearing technology is commonly used to keep thermal effects from being a limiting factor in most practical flywheel systems. Vacuum containment and magnetic bearings can also significantly reduce friction and heat generation. The trade-off is that they also can make it difficult to remove the heat that remains. In flywheels with bearing enhancements, thermal energy normally leaves the rotor only through radiation, sometimes requiring special heat removal methods within the enclosure.

Some manufacturers have chosen to include active cooling systems in their products, through the use of a low viscosity gas in the containment system. Some investigators have suggested hydrogen cooling, similar to the technique used for large electric generators [3].

Subsystem and Components

A flywheel has several critical components. These components will be discussed in further detail in the following subsections (See Figure 13-3).

- **Rotor –** a spinning mass that stores energy in the form of momentum.
- **Bearings –** pivots on which the rotor rests.
- **Motor-Generator –** a device that converts stored mechanical energy into electrical energy, or vice versa.
- **Power Electronics –** an inverter and rectifier that convert the raw electrical power output of the motor/generator into conditioned electrical power with the appropriate voltage and frequency.

- **Controls and Instrumentation –** electronics which monitor and control the flywheel to ensure that the system operates within design parameters.
- **Housing –** Containment around the flywheel system, used to protect against hazardous failure modes. It is sometimes also used to maintain a vacuum around the rotor to reduce atmospheric friction.

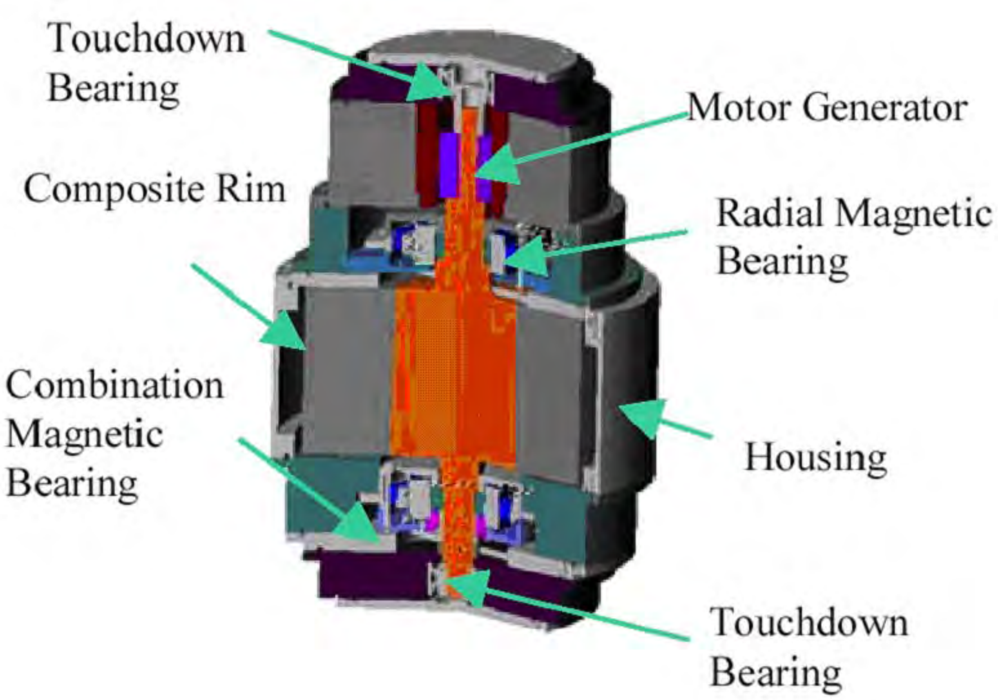

Figure 13-3
Cross-Section of a Flywheel Module (*Courtesy NASA Glenn Research Center*)

Rotor Design and Construction

The rotor, as the energy storage mechanism, is the most important component of the flywheel energy storage system. As described above, rotors are designed to maximize energy density at a given rotational speed, while maintaining structural integrity in the face of rotational and thermal stresses.

Rotor designs can be divided into two broad categories: "low-speed" rotors and "high-speed" rotors. While these categories are somewhat arbitrary, and some designs do not fit neatly into one category or the other, they are useful to draw some general distinctions. Both types of rotors have advantages and disadvantages, and the two find uses in different applications [1].

Low-speed rotors are typically heavy steel discs which rotate at speeds less than 10,000 rpm. These rotors can be designed with either a vertical shaft or a horizontal shaft. They are usually supported on mechanical bearings, which are sometimes augmented with magnetic bearings to reduce friction and wear. The rotors are usually placed in a containment vessel, which is reinforced to provide protection in the event the wheel comes apart while it is spinning. The vessel is filled with air or a low-friction gas such as helium to reduce friction.

High-speed rotors require materials such as graphite composites and fiberglass, which are lighter but stronger and allow much higher rotational velocities. They are usually designed with a vertical shaft. These wheels typically spin at speeds above 10,000 rpm, and some designs exceed 100,000 rpm.

Examples of each of these types of flywheels are illustrated in Figure 13-4 and Figure 13-5.

Figure 13-4
Low-Speed Horizontal-Shaft Steel Flywheel (Courtesy Satcon Power Systems)

Figure 13-5
High-Speed Vertical-Shaft Composite Power Flywheel

The physical construction varies of flywheels with vertical and horizontal shafts, flywheel speeds, and simply from one manufacturer to another. Figure 13-6 shows the relative physical size and profile of several commercially available flywheel systems. Note that the Satcon unit profile also includes a standby generator, which is connected on the same shaft as the flywheel and generator.

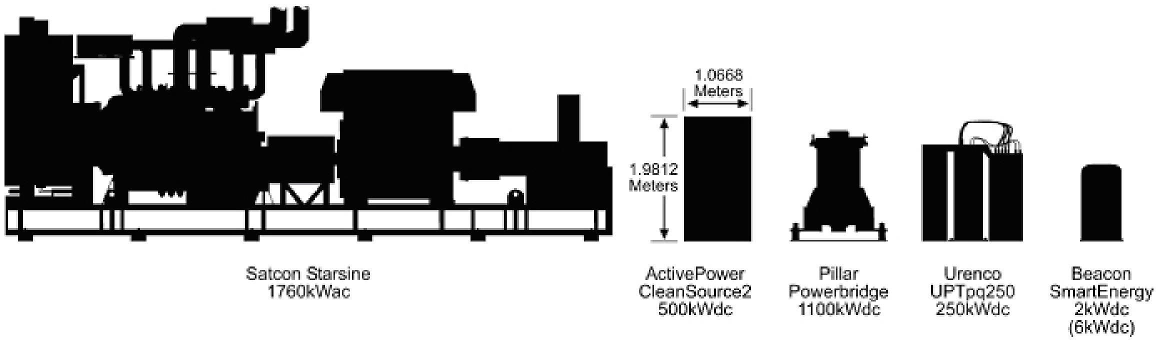

Figure 13-6
Silhouettes of Several Commercially Available Flywheel Systems

Rotor Bearings

The bearings support the flywheel rotor and keep it in position to freely rotate. The bearings must constrain five of the six degrees of freedom for rigid bodies, allowing only rotation around the axis of the rotor. The construction of the bearings is important in flywheel performance. The speed of the flywheel 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.

There are several types of bearings used in flywheel construction. Mechanical bearings are the simplest form of flywheel bearings. These might be ball, sleeve, roller, or other type of mechanical bearing. These bearings are well understood, reliable, and inexpensive, but also suffer the most wear and tear, and produce the largest frictional forces, inhibiting high rates of rotation.

Magnetic bearings are required for high-speed flywheel systems. These bearings reduce or eliminate frictional force between the rotor and its supports, significantly reducing the intrinsic losses. There are several types of magnetic bearings. Passive magnetic bearings are simply permanent magnets, which support all or part of the loads on the flywheel. Active magnetic bearings, on the other hand, use controlled magnetic fields, where field strength on the bearing axes is varied to account for the effect of external forces on the rotor. Superconducting bearings are passive magnetic bearings, which use superconducting materials to produce the magnetic repulsive force to support the rotor assembly. These materials operate at very low temperatures, and so require cryogenic cooling systems to maintain.

Magnetic bearings do not completely eliminate power drain. The geometry and variance in the magnetic fields of the bearing will cause some loss factor in the rotor speed. Magnetic bearing failure must also be taken into consideration, especially for active bearings. In most designs, magnetic bearings are used in conjunction with mechanical bearings. The mechanical bearings prevent damage in the event that the magnetic bearings fail, while the magnetic bearings reduce friction and wear and tear resulting from the mechanical bearings [4].

Motors and Generators

Motors convert electrical energy into the rotational mechanical energy stored in the flywheel rotor during charge, and generators reverse the process during discharge. In many modern flywheels the same rotating machine serves both functions. The machine is called a motor-alternator or motor-generator and consists of a wound- or permanent-magnet rotor, usually revolving within a stator containing electrical winding through which charge (or discharge) current flows. Note that this machine, along with any power electronics, limits the power rating of the flywheel system. In addition, in some practical systems the generator for discharging the wheel has a higher power rating than the recharging motor, so that charging the wheel will require more time than discharging.

The starter motor and alternator or generator are connected to the flywheel via the same steel shaft and may be either a single machine or two different machines. When separate, the starter motor is typically a simple induction motor that is able to produce starting torque. When combined in one synchronous motor/alternator, with either permanent magnet or wound rotor, electronics are required to spin up the flywheel. In this configuration, the power electronics are also used to convert the variable output frequency to a constant 60-Hz frequency. Figure 13-7 shows both arrangements.

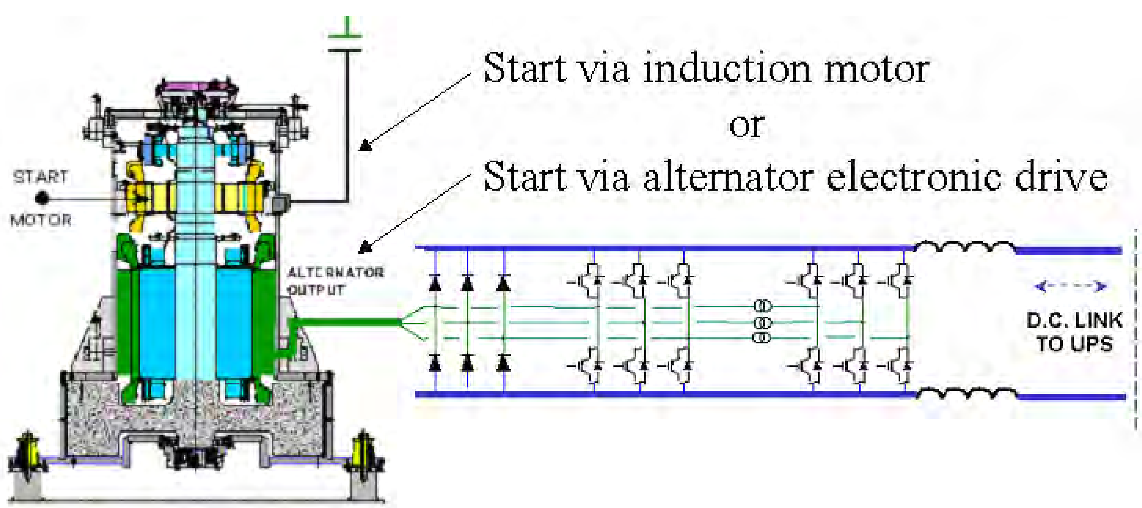

Figure 13-7
Two Possible Flywheel Charging Configurations: Induction Motor Starter and Power Electronics for Starting and Frequency Control (Courtesy Of Piller Premium Power Systems)

In some models the magnets in the machine rotor are embedded within the flywheel rotor itself, which rotates around a stator containing the electrical windings. This arrangement usually improves the energy and power density of the system, but makes thermal management more challenging [3].

Power Electronics and Electro-Mechanical Couplings

Most flywheel energy systems have some form of power electronics that convert and regulate the power output from the flywheel. As the motor-generator draws on mechanical energy in the rotor, the rotor slows, changing the frequency of the AC-electrical output. The output must be converted to dc or to constant-frequency ac power. This can be done through the use of power electronics, in the form of rectifiers and inverters, or through electromechanical methods, such as the eddy-current clutch and induction coupling.

Power electronics have won this competition in all the high-speed wheels on the market. However several high-power, low-speed systems use electromechanical couplings to isolate the shaft and effectively couple an accelerating and decelerating flywheel with a constant-speed generator. Whether electronic or mechanical, these devices allow energy to be taken from the wheel before its frequency and power output drop below usable levels. In fact, the low-end (i.e., end-of-discharge) cutoff speed at which the flywheel is considered discharged is primarily dependent on the current carrying capability of the electronics (or electromechanical coupling) and the size of the load. For example, most flywheels have output current proportional to load and inversely proportional to speed. This means a lighter load can go to a lower speed before the system cuts out on maximum current. The flywheel system can actually deliver 1.5 to 2 times more energy at light load than high load. In this feature the flywheel performs in way similar to conventional batteries (through for different reasons).

When power electronics are used, the variable frequency ac output of the flywheel alternator is simply rectified, providing a dc voltage and current. From this point an inverter may be used to recreate ac at the desired waveform, frequency and voltage. So the function of the power electronics is to couple the fixed-frequency AC electrical grid with the variable-speed flywheel and also to invert, regulate, and provide wave shaping for the AC electrical output of the system. By reversing the process, the power electronics are also able to draw power from the AC line connection and drive the flywheel motor to spin up and recharge the wheel. The most common power electronic systems use two matching bi-directional or 4-quadrant converters to carry out all of the functions described here.

Controls and Instrumentation

Flywheel systems require some controls and instrumentation to operate properly. Instrumentation is used to monitor critical variables such as rotor speed, temperature, and alignment. Rotor speed and alignment are also often controlled variables, through active feedback loops. The latter is especially important for systems with magnetic bearings, and most magnetic systems have complex controls to reduce precession and other potentially negative effects on the rotor.

In many systems, other instrumentation is used to monitor performance or design parameters related to failure modes. In some composite flywheel systems, for example, instrumentation is used to measure deformation of the rotor over time, alerting operators when the rotor shape indicates possible failure in the future.

System Packaging

Most modern flywheel systems have some type of containment for safety and performance enhancement purposes. This is usually a thick steel vessel surrounding the rotor, motor-generator, and other rotational components of the flywheel. If the wheel fractures while spinning, the containment vessel would stop or slow parts and fragments, preventing injury to bystanders and damage to surrounding equipment.

Containment systems are also used to enhance the performance of the flywheel. 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. Figure 13-8 illustrates a typical system packaging approach.

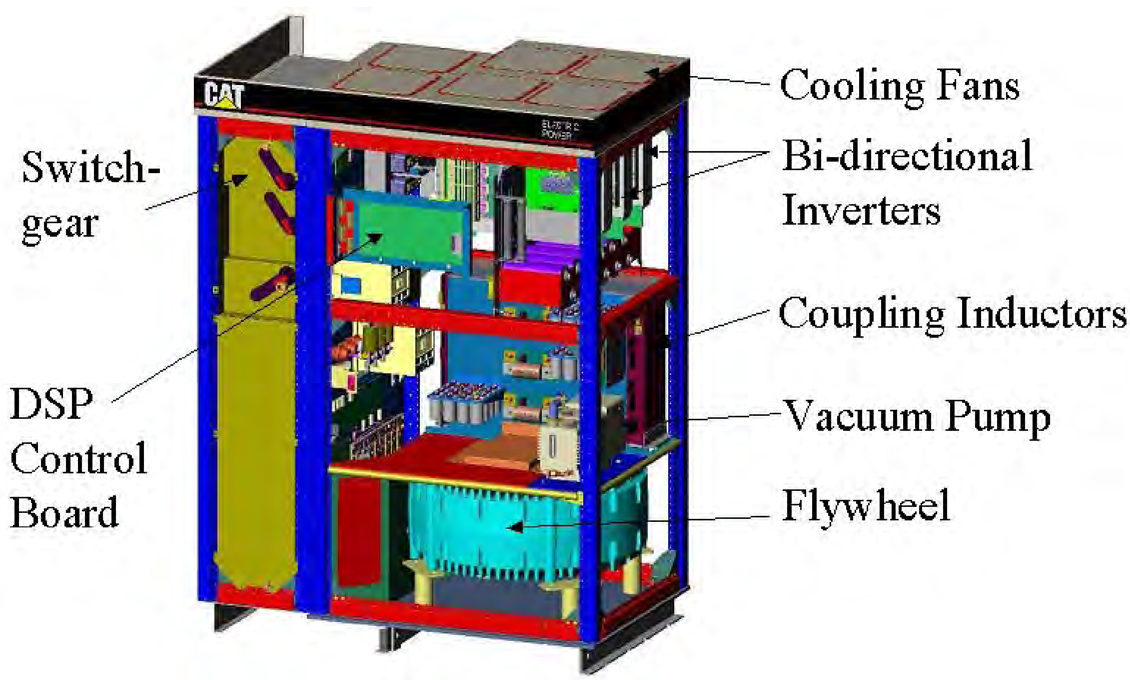

Figure 13-8
CAT UPS Integrated Flywheel System Cutaway Diagram *(Courtesy Of Caterpillar)*

Features and Limitations

Table 13-1 lists some of the major advantages and disadvantages of flywheel energy storage systems.

Table 13-1
Advantages and Disadvantages of Flywheel Energy Storage Relative to Other Energy Storage Technologies

Advantages	Disadvantages
Power and energy are nearly independent	Complexity of durable and low loss bearings
Fast power response	Mechanical stress and fatigue limits
Potentially high specific energy	Material limits at around 700M/sec tip speed
High cycle and calendar life	Potentially hazardous failure modes
Relatively high round-trip efficiency	Relatively high parasitic and intrinsic losses
Short recharge time	Short discharge times

The specific features and limitations of flywheel systems are examined in the sections below.

Power Capacity

As noted above, the energy stored by a flywheel is determined by the mass and speed of the rotor, while the maximum power is determined by the characteristics of the motor-generator and power electronics. This means that the energy and power characteristics of a flywheel system are more or less independent variables, allowing optimization of both characteristics independently. This is in contrast with most other energy storage devices. In most batteries, for instance, both energy and power are determined by the size and shape of the battery electrodes.

Because of this independence, flywheel systems can, in theory, be designed for any power and energy combination. In practice, design characteristics are limited by technical considerations such as rotor strength and weight and motor-generator size, as well as resource considerations such as cost.

Flywheel systems are typically designed to maximize either power output or energy storage capacity, depending on the application. Low-speed steel rotor systems are usually designed for high-power output, while high-speed composite rotor systems can be designed to provide either high power or high-energy storage.

When designed for power, and where electric power conversion is adequately sized, flywheels can deliver relatively high power for a short period of time. Most power flywheel products presently available can provide from 100 to 2000kW$_{ac}$ for a period of time ranging between 5 and 50 seconds.

It should be noted that power systems rated below 500 kW, particularly those using high-speed rotors, are usually rated in kW$_{dc}$. Larger systems, particularly those using low-speed steel flywheels, are usually sold as integrated AC-output systems and are rated in kVA.

The power capability of flywheel systems can be far larger than these commercial systems, however. The largest flywheel built to date is an 8000MJ system built by the Japan Atomic Energy Research Institute (JAERI) for use in fusion energy research. This system uses a steel wheel to deliver up to 340MW for as long as 30 seconds [5].

Energy and Efficiency

The energy stored in a flywheel depends on mass and rim surface speed. For flywheels, the important parameter is rotational velocity or rim surface speed, which is circumference times the rotational speed (in rpm). For example, a small 0.5 kWh flywheel has a relatively small rotor and may spin at 100,000 RPM; whereas a heavier 6-kWh flywheel has a bigger rotor and maintains the same rim surface speed at only 20,000 RPM. Therefore, flywheel systems designed for high energy as opposed to high power tend to have rotors with larger diameter, taking advantage of weight and increased rim speed. Nonetheless, the rim velocity is physically limited by practical material strengths to a speed of about 2000 m/s.

Round-trip efficiency and standby power loss become critical design factors in energy flywheel design since losses represent degradation of the primary commodity provided by the storage system (energy). However, they are largely irrelevant in power flywheel design (although standby losses are a factor in operating cost in comparison with other power technologies that have significantly lower losses). For these reasons, energy flywheels usually require more advanced technologies than power flywheels [3]. These energy flywheels usually have composite rotors enclosed in vacuum containment systems, with magnetic bearings. Such systems typically store between 0.5 and 10 kWh. The largest commercially available systems of this type are in the 2-6 kWh, with plans for up to 25 kWh. All energy flywheels available today are DC output systems.

Round-trip efficiencies for energy flywheels usually fall between 70 and 80%. The standby losses are very small, typically less than 25 W$_{dc}$ per kWh of storage and in the range 1 – 2% of the rated output power.

Calendar and Cycle Life

The nature of flywheel systems means that there is at least one moving part, the rotor itself. As might be expected, 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. This life-limiting issue can be mitigated by 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 charge-discharge cycles. The rotor is subject to fatigue effects arising from the stresses applied 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 [1]. Appropriate design and operation precautions must be taken in order to ensure safe operation (see Safety, below).

In graphite rotors, cracks tend to propagate longitudinally, resulting in the delamination of the concentric layers of material. This phenomenon causes the rotor to gradually deviate from normal operation. Thus, monitoring of suitable operating parameters will ensure that the device can be removed from service before a hazardous failure mode occurs [1].

Recharge Time

Flywheels can be charged relatively quickly. Recharge times are comparable to discharge times for both power and energy flywheels designs. High-power flywheel systems can often deliver their energy and recharge in seconds, provided that adequate recharging power is available. Bi-directional power conversion facilitates this two-way action.

In stabilizer applications the controls may be designed to provide a negative feedback so that the rates of charging and discharging depend on voltage or frequency. In this case, charging may occur quickly and discharge slowly or vice versa.

There are some instances in which the motor used to charge the flywheel is separate from the generator used to discharge it. In these instances, the recharge time depends on the power rating of the motor, while the discharge time depends on the power rating of the generator.

Standby Power Loss

Flywheel systems have standby power losses which cause the energy stored to be gradually lost, even when discharge does not occur. A certain amount of power must be applied to maintain a high level of charge if the flywheel is used in a standby mode. The magnitude of the power loss is dependent on the design of the flywheel, and may have both intrinsic and parasitic components.

Intrinsic power losses include friction and other forces that cause the rotor to slow down, and are common to all flywheel designs. Intrinsic power losses can be reduced through the use of techniques such as vacuum containment and magnetic bearings, but can never be reduced to zero.

Parasitic power losses include power provided to active magnetic bearings or cooling for superconducting bearings. Unlike intrinsic losses, parasitic power losses are independent of the speed of the flywheel. Not all flywheel systems have parasitic power losses [3].

The difference between intrinsic and parasitic losses is worth noting. Methods used to reduce intrinsic losses often lead to increases in parasitic losses, so that a trade must be done to ensure that there is a net reduction in standby loss.

Electrical Interface

The electrical interface, where the flywheel mechanical or kinetic energy is converted to electrical energy, and vise versa, can vary greatly with different flywheel types and applications. There are a number of rotating machine technologies that can be used in flywheels for generating (during discharge) and restarting (after discharge). These include permanent magnet alternators as well as DC, synchronous, wound-rotor induction, and written-pole motors and generators. These machine technologies can be matched with different forms of power electronic and electromagnetic frequency conversion technologies to create a wide variety of systems. Also in the mix are application-specific filtering or conditioning, paralleling, isolation, transfer, and back up generator equipment. This results in the practical reality that no two-flywheel systems on the market in 2003 use exactly the same electrical interface.

The parameters that determine electrical interface design are flywheel rotor speed, electrical loading (AC or DC), response time, parallel or series connection, need to interface with an alternate source, and the need for high power or high energy. With all these variables, the variety in electrical interface is understandable.

In all cases, energy loss is a critical parameter that must be minimized, partly through electrical interface design. The interface design of most of the flywheels on the market allow suppliers to claim above 90% overall system round trip efficiency with standby losses of less than 3%. Table 13-2 provides an overview of the combinations of equipment that are typically used in the flywheel electrical interface.

A good example of the application influence on the flywheel electrical interface is the bridge power system. In this application, when prime power is lost, the flywheel system takes over and must operate as a standalone generator, with load following, voltage and frequency control until an alternate power source is available. At that point, the flywheel system electrical interface synchronizes and transfers the load to the alternative source and begins the recharging sequence. This interface is typical for systems that have an integrated diesel engine or other backup generation.

Table 13-2
Typical Combinations of Electrical Interface Equipment in Flywheels

Size Range	Rotor Speed	Mech. To Electric Converter	Frequency Converter	Load Type	Recharge Starter	Eff. %
<500 kW	High	PM[1] Alternator	Rectifier/Inverter.	AC	PM Motor/ASD[2]	95
<500 kW	High	PM Alternator	Rectifier	DC ASD	Induction Motor	92
<500 kW	Med.	DC Generator	Rectifier/Inverter.	AC	DC Motor	95
<500 kW	Low	Written-pole Gen	Variable Poles	AC	Induction motor	85
>1 MW	Low	Synchronous Generator	WR Induction Coupling	AC	Synchronous Motor	97
>1 MW	Low	WR[3] Alternator	Rectifier	DC	Induction Motor	93
>1 MW	Low	Wound Rotor (WR) Induction Generator	Double output Induction Generator	AC	WR Induction Motor	96
>1 MW	Low	WR Alternator	Rectifier/Inverter.	AC	Synchronous Motor/ASD[2]	96

[1] The permanent magnet (PM) machines are preferred in high-speed applications because they are more durable than electrical winding under mechanical forces on the spinning rotor.
[2] An adjustable speed drive (ASD) allows speed matching between the power source moving magnetic field (MMF) and the machine rotor poles. In the case of a PM alternator or synchronous machine, the machine only produces torque when the source MMF matches the rotor pole speed. This is not the case in induction machines, which produce torque (for starting) at zero rotor speed.
[3] Wound rotor (WR) machines are preferred in low speed applications where larger structures are needed to obtain high energy.

Safety

As with any energy storage technology, hazardous conditions may exist around operating flywheels. Considerable effort has gone into making flywheels safe for use under a variety of conditions.

The most prominent safety issue in flywheel design is failure of the flywheel rotor while it is rotating. In large, massive rotors, such as those made of steel, failure typically results from the propagation of cracks through the rotor, causing large pieces of the flywheel to break off during rotation. Unless the wheel is properly contained, this type of failure can cause damage to surrounding equipment and injury to people in the vicinity. Large steel containment systems are employed to prevent high-speed fragments from causing damage in the event of failure.

Composite flywheels have other failure mechanisms, usually through gradual delaminating of the concentric layers of the rotor, or through vertical delaminating, or crack propagation parallel to the axis of rotation. In most cases, these failure mechanisms cause noticeable deviations from normal operational behavior long before catastrophic failure, and control mechanisms are often used to catch impending failure conditions [6]. Nonetheless, the possibility of hazardous failure modes cannot be completely ruled out, and containment systems are also applied to composite flywheel systems, in part to enhance the perceived safety factor for such devices. Some systems are installed underground to further improve containment.

As with any electrical equipment, care must be taken to avoid accidental electrical discharge. Standard electrical codes and procedures can be applied to flywheel construction to prevent these failure modes from occurring.

Environmental

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 70dB at 6 feet [3]. On the other hand, high-speed systems with vacuum containment are considerably quieter, and those that are installed underground can be unnoticeable.

Status

There is an ever-growing selection of new flywheel products on the emerging on the coattails of advances in technology. Consequently there are also a number of applications that now propose using flywheels as the energy storage medium. These include inrush control, voltage regulation and stabilization in substations for light rail, trolley, and wind generation stabilization. Still, the majority of products currently being marketed by national and international-based companies are targeted for power quality (PQ) applications. And the number one application in power quality is short-term bridging through power disturbances or from one power source to an alternate source. Flywheels are being marketed as environmentally safe, reliable, modular, and high-cycle life alternatives to lead-acid batteries for uninterruptible power supplies (UPSs) and other power-conditioning equipment designed to improve the quality of power delivered to critical or protected loads.

Major Manufacturers and Systems

Although the majority of products being sold and marketed today fit into the PQ niche market, there are a number of key areas where electric utilities can directly benefit from the use of available flywheel systems. These include hybrid distributed energy resources (wind and flywheel, photovoltaic and flywheels, etc.), T&D grid stability (e.g., mass transit substation support), and potentially diurnal load leveling (peak shaving). This section focuses on existing and emerging flywheel products that may have applicability to utility T&D operations and will address product availability, performance characteristics, cycle life, and expandability/modularity.

Table 13-3 lists the best-known manufacturers of flywheel systems for utility applications at present, along with the names and characteristics of their main products. The following sections describe these manufacturers and the special features of their products with respect to other flywheel systems.

Table 13-3
Major Flywheel Manufacturers and Their Products

Manufacturer	Product Name	Rotor Type[1]	Nominal Standby Rotor Speed (rpm)	Rotor Environment	Bearing Type	Power Rating	Discharge Time	Recharge Time	Standby Power Loss[2]
Active Power	CleanSource	Steel	7,700	Rough vacuum	Magnetic & Mechanical[3]	250 kW_{dc}	13.5 sec	2.5 min @ 60 kW_{dc}	0.76%
Piller	Powerbridge	Steel	3,600	Helium	Magnetic & Mechanical[3]	1100 kW_{dc}	15 sec	60 sec	4.5%
Hitec (formerly Holec)	Continuous Power Supply (CPS)*	Steel	3,600	Air	Mechanical	275 - 2000 kVA	10 sec	10 sec	2.5%
SatCon	Starsine Rotary UPS*	Steel	1,800	Air	Mechanical	315 – 2200 kVA	12 sec	12 sec	2.3%
AFS Trinity	M3A	Graphite Composite	40,800	Vacuum	Active Magnetic	100 kW_{dc}	15 sec	15 sec	0.70%
Pentadyne	VSS 120	Graphite Composite	55,000	Vacuum	Active Magnetic	120 kW_{dc}	20 sec	20 sec	0.10%
Urenco Power Technologies	tr200	Graphite Composite	36,000	Vacuum	Magnetic	250 kW_{dc}	30 sec	30 sec	0.28%
Beacon Power	SmartEnergy BHE-6	Graphite Composite	22,500	Vacuum	Active Magnetic	2 kW_{dc}	3 hrs	2.5 hrs @ 4kW_{dc}	3.5%

[1] Products are listed based on likely application with higher power flywheels listed first followed by higher energy systems.
[2] Standby power loss is given as a percent of rated power. Where rated power is a range, the maximum power is used for this calculation.
[3] These systems use electro-magnets for lifting of a vertical shaft wheel to reduce the weight on lower mechanical bearings.

Active Power

Active Power, located in Austin, Texas, manufactures AC and DC power quality systems based on low-speed power flywheel systems to provide a brief ride-through or bridge to a standby generator when voltage is low or power is not available. The company was founded in 1996 with private funding from various venture sources, and has since issued public stock, trading on the NASDAQ exchange under the ticker symbol ACPW.

Active Power is rather unusual among flywheel manufacturers in having a steel wheel design that incorporates many of the features of higher speed composite wheels. The flywheel operates in a low and relatively wide speed range from 7700 to 2000 rpm, and is contained in a near vacuum environment. According to the company, the decision to go with steel rotors was made to avoid the technical difficulties and expense associated with composite rotors, active magnetic bearings, complex controls, and containment systems required at high rotor speeds.

Figure 13-9
Cutaway Diagram of Active Power Flywheel System (Courtesy Active Power)

The heart of Active Power's product is a 14" high, 32" in diameter integrated motor, generator and flywheel storage system that is capable of storing and delivering up to 250kW$_{dc}$ to the DC bus of a UPS. The flywheel stores energy as angular momentum in a single-piece, forged 4340 steel wheel rotating in a near vacuum. The motor/alternator, characterized as a "homo-polar induction alternator," has a novel design. There are no permanent magnets used, nor are there wound rotor type coils or magnets on the rotor. No brushes are employed. A field coil structure above and below the wheel magnetizes the rotor and produces characteristics of a salient pole generator. By driving higher current in the upper coil the magnetic structure supports most of the rotor weight via integral upper and lower magnetic ring bearings. This unloads the mechanical bearings to about 100 lbs and greatly extends their life.

The Active Power flywheel is incorporated into several products. Active Power directly markets flywheels with dc voltage output under a line of products under the name CleanSource DC as well as through strategic partners, Powerware and General Electric Digital Energy. This is a line of DC flywheel products sized to match applications between 100 kW_{dc} (for the CSDC 100) to 500 kW_{dc} (for the CSDC 500), which can be paralleled to 2 MW_{dc}. These products all use the same 0.95 kWh flywheel, with varying power electronics. The CSDC 425 and 500 use two flywheels together to achieve higher power levels. All CleanSource DC products have programmable DC output voltage settings between $360V_{dc}$ to $550V_{dc}$, although full DC power is not available below a setting of 480 V_{dc}.

Active Power also sells complete AC systems, which combine flywheels in cabinets with AC inverters to provide three-phase power-regulated uninterrupted power. Active Power markets its integrated flywheel UPS AC systems through its strategic partner, Caterpillar. It also markets these systems directly in some regions. Caterpillar is currently marketing this AC system through dealerships world-wide as the Caterpillar UPS, a battery-free UPS system. These UPS systems can be designed to serve loads from 150 kVA to 1200 kVA, and can be paralleled to serve loads up to 3600 kVA.

Active Power recently expanded its line of flywheel UPS systems. The company recently released a lower power AC flywheel system rated for 65 kVA to 130 kVA. This product is marketed under Active Power's CleanSource brand. Shipment of a 1200 kVA version of the Cat UPS began in the second half of 2003. The company continues its work on advanced technology to expand application of battery-free energy storage beyond its current flywheel technology [7,8,9,10,11].

AFS Trinity

AFS Trinity, based in Medina, Washington, is the result of a merger between American Flywheel Systems (AFS) and Trinity Flywheel Power in 2000. The company has licensed composite flywheel technology from Lawrence Livermore National Laboratories to produce their short discharge time flywheel system.

The AFS Trinity system uses a high-speed, high-strength carbon composite rotor contained within a vacuum housing and is mounted on active magnetic bearings. The AFS Trinity system is unusual in the "inside-out" configuration of the motor/generator: permanent magnets are fixed in the core of the rotor, and revolve with the rotor around a stator inside the core. This system eliminates the shaft connecting the flywheel to the generator.

AFS Trinity has plans to market two products, the M3A and the M4A. The former, scheduled to become commercially available in 2004, is a $100kW_{dc}$ power flywheel system for use in power quality and short ride through applications. The M4A is a larger, 250 kW_{dc} device, planned to become available at an unspecified later date [12, 13].

Beacon Power Corporation

Based in Wilmington, Massachusetts, Beacon Power was formed in 1997 when SatCon spun off its Energy Systems Division. Beacon became a separate entity in 1998 as a SatCon subsidiary and became a publicly traded company in November 2000. It is traded on the NASDAQ exchange under the ticker symbol BCON.

The company initially focused on energy storage flywheels for telecom applications, and developed the highest stored-energy, commercially available flywheel products in the world. Its high-energy telecom flywheel systems are operating in about a dozen field locations in North America, South Africa and Israel, and have accumulated over 300,000 hours of successful operation as of September, 2003. Beacon is also marketing high-power flywheel systems for UPS applications, and has recently proposed an innovative flywheel power station that can deliver "megawatts for minutes" for high-power distributed generation applications.

Beacon offers flywheel technologies over a range of low and high power, from 2 kW_{dc} to 250 kW_{ac}. For low power, the company has a 6-kWh flywheel that delivers up to 2 kW_{dc}, for a long period of time–up to 3 hours at full rated load for remote terminal telephone and cable applications, longer at reduced power. In the high power market, Beacon sells a 250 kW_{ac} flywheel system for short durations. The flywheel for this system is the 250 kW_{dc} system manufactured by Urenco Power Technologies, with an inverter/rectifier system designed, built, and integrated by Beacon. This system is designed to economically provide longer run-time than many other available flywheels, up to 25 seconds at 250 kW_{dc} vs. the typical 12-15 seconds. This type of flywheel delivers a relatively small amount of energy. (e.g. 250 kW_{dc} for 25 sec is only 1 kWh).

In 2003, Beacon announced plans to begin work on a new type of long-duration, high-speed flywheel-based system called the Smart Energy Matrix (SEM), especially for transmission and distribution stability applications. This system is based on a new 25 kWh flywheel designed to increase energy density while reducing cost.

The rotor for the new 25 kWh design is about 2.5 feet in diameter, larger that than most high-speed competitors, and spins at about 16,000 rpm. The longer radius allows the flywheel to maintain the same rim speed despite the lower rotational speed, producing high energy density. The much higher energy content justifies the relatively high cost of the graphite composite material.

In the SEM concept, ten 25 kWh flywheels would be placed in a deployable container, along with control electronics and equipment. A 4-quadrant power conditioning system, capable of providing VAR compensation, would be included. This would allow the owner to provide VAR compensation in addition to frequency regulation, increasing the net benefit.

Each container will constitute a 250 kWh module capable of delivering from 1 MW_{ac} to 2.5 MW_{ac} for periods up to 15 minutes. These modules will have the ability to be connected together for system power deliveries of 10-20 MW_{ac} or more.

Figure 13-10
Beacon 25kW-h Flywheel (Courtesy Beacon Power)

As of October 2003, Beacon had completed the design of the 250 kWh flywheel and the Smart Energy Matrix system, and has approached utilities and other potential investors for funding to develop and qualify the product. If funding is found, it is expected that the product will be available by 2006 [14,15,16,17].

Hitec Power Protection

Hitec (formerly known as Holec Power Protection) is a Dutch company that has been manufacturing its Continuous Power Supply (CPS) for over thirty years. Recent versions of the CPS have incorporated an unusual system using a flywheel within an inductive coupling to provide bridging power.

The CPS is composed of four parts: a diesel engine, a free-wheel clutch, an induction coupling, and a synchronous generator. The generator is connected to the AC utility line in parallel with the load. The clutch disengages the generator from the diesel engine, allowing the generator to spin, as a motor when utility power is available. The generator is connected mechanically to the induction coupling, which consists of two concentric rotors. The outer rotor is directly connected to the generator on one side and to the diesel engine, via the clutch, on the other, and contains AC and DC windings that couple it to the freewheeling inner rotor.

When the AC windings are energized the outer rotor, spinning at 1800 rpm, becomes a two-pole stator as in an induction motor. And this induction acts on the inner rotor, spinning it up to nearly 5400 rpm, where it acts as a flywheel. When utility power is lost the DC windings of the other rotor take over and hold the generator shaft at 1800 rpm by coupling with the inter rotor and controlling the slip as it is decelerating. This provides enough time for the diesel generator to turn on, come up to speed and pick up the load via the eddy current clutch, providing power for as long as the fuel holds out or until utility power becomes available.

Pentadyne

Pentadyne Power Corporation of Chatsworth, CA is a manufacturer of high-speed graphite composite flywheel systems for high-power applications. Paul Craig, former CEO of Capstone Turbine Corporation, founded the company in 1998. The company owns technology from Rosen Motors (now closed), which had developed flywheel technologies for use in electric and hybrid-electric vehicles.

Figure 13-11
Pentadyne VSS 120 Power Quality Flywheel (Courtesy Pentadyne Power Corporation)

In 2003, Pentadyne released the VSS 120, a battery replacement / augmentation for a UPS system, which targets the power quality market. The VSS 120 is a high-speed power flywheel system, which provides 120 kW_{dc} for up to 20 seconds(0.67 kWh). It applies a synchronous reluctance motor-generator with a power electronic rectifier/inverter to provide a regulated DC output, which can then be connected to an industrial UPS inverter. The VSS 120 also has an internal, maintenance-free vacuum system.

By early 2004, Pentadyne expects to have eighteen VSS 120 beta-prototype products placed at a variety of test sites. At most of these sites, the VSS 120 will be used for power quality purposes. The product is also being tested, however, as a ride-through for adjustable-speed drives (ASD) and in a power-assist application with a microturbine.

The company continues to focus on power quality applications. Products delivering higher power for shorter durations are currently being designed. The company is also investigating other applications, such as power recycling. In this application, energy is absorbed from a DC bus when an excess of power is present, and discharged when the power is needed. An example of this application is its use in electric rail mass transit systems, where flywheels can absorb energy from the bus when trains are stopped and redeliver it when they accelerate [19,20,21].

Piller Premium Power Systems

Piller Premium Power Systems of Middletown, New York, is a member of the RWE family of companies, which is headquartered in Germany. Piller builds a low-speed power flywheel system for ride-through applications, which it calls the Powerbridge. The Powerbridge unit consists of a massive steel wheel that discharges from a nominal speed of 3600 rpm down to 1800 rpm, and is contained within an enclosure surrounded by helium. The system is sized to deliver 1100 kW_{ac} for 15 seconds. Piller is somewhat unusual among low-speed flywheel manufacturers for using magnetic lifting in the vertical shaft system to reduce the weight on the mechanical lower bearing in its system.

Piller also uses power electronics in a different way than others. The flywheel is built into their Powerbridge product, which can be combined with other equipment such as the Piller Uniblock-T UPS. Included in the UPS are the flywheel with alternator and starter motor, a rectifier/inverter, and a vertical shaft synchronous motor/generator. For the Uniblock-TD product, Piller substitutes a horizontal shaft M-G and adds a diesel generator. In the event that utility power fails, the Powerbridge system provides ride-through power long enough for the diesel generator to start up and take over.

Like several other manufactures of >1MW flywheels, Piller physically separates the flywheel housing from the generator housing. However, Piller applies a unique approach of coupling the flywheel and AC generator via power electronics. In this configuration, the power electronics serve as the frequency converter, but leaves power conditioning, wave-shaping, and regulation functions to the output of a conventional synchronous AC generator [22].

SatCon Power Systems

SatCon Power Systems a Division of SatCon Technology Corporation is based in Worcester, MA where they manufacture flywheel systems with ratings from 315 to 2200 kVA. SatCon’s first entry in the field is the large low-speed flywheel system incorporated into a rotary UPS that includes a back up diesel generator, called the Starsine Rotary UPS. The Starsine uses a large steel wheel that operates between 1980 and 1620 rpm and discharges via an induction generator using rotor power electronics to compensate for the speed change. They are targeting applications that provide continuous power for process industries. However, with some modifications to the power electronics and rotor current rating, the system may be suitable for higher powers for 1-2 seconds in a utility scale stabilizer application.

The SatCon UPS product will operate in a fashion similar to other bridge-power devices, providing 12 seconds of ride-through power to cover short power quality events or momentary service interruptions, and relying on the diesel engine to cover longer interruptions. SatCon is unique among flywheel manufactures in their use of power electronic controls integrated into an induction generator, sometimes referred to as a doubly fed or double-output induction generator. This technology provides a soft interface between the variable speed flywheel or diesel generator and the fixed frequency of the load bus. Because of the interface, SatCon expects to be able to parallel several flywheels without added paralleling switch gear and control.

Urenco Power Technologies

Urenco is a British company best known for uranium enrichment processes, for which they have developed and manufactured high-speed, composite gas centrifuges over the past thirty years. Urenco's flywheel technology is a direct spin-off from this experience and is being commercialised in a subsidiary called Urenco Power Technologies (UPT). Like the centrifuge, the UPT flywheel uses a composite rotor and the same type bearing system that has allowed many of Urenco’s early centrifuges to run continuously for over twenty years.

For the power quality market, UPT builds two models; one sized to provide 100kW_{dc} and a more recent version capable of providing 250kW_{dc}. Both systems provide full power for about 30 seconds. It should be noted that this high-speed flywheel provides as much power as many of the low-speed flywheel ride-through devices, for a longer period of time and in a much smaller flywheel package. On the other hand, auxiliary electronics and cooling add to the package size and weight. UPT's flywheel is a DC output device and can be coupled with an inverter/rectifier if AC power is required. Beacon Power has plans to market a system incorporating a UPT 250kW_{dc} flywheel together with an inverter/rectifier, under the Beacon label as the SmartPower BHP-250.

The UPT flywheels are also being used in power management applications where the requirement is for repeated charge/discharge cycles. Examples include voltage support and energy saving in mass transit systems and power smoothing with wind turbines [24, 25].

Recent Developments in Flywheel Technology

There are two major avenues of research in flywheel technology at present: improved passive magnetic bearings, and improved wheel materials. Research into these avenues is being conducted in various facilities, including universities, government laboratories, and in industry.

Table 13-4 lists important flywheel technology developers and the technology they are best known for developing.

Table 13-4
Major Flywheel Research Groups

Developer	Development Area
Boeing Phantom Works	High Temperature Superconducting Bearings
Lawrence Livermore National Laboratories	Passive Magnetic Bearings
Pennsylvania State University	Composite rotor materials
University of Texas	Composite rotor materials

Magnetic Bearings

Research into new magnetic bearings is a significant part of flywheel research at present. New developments in active magnetic bearing technology have built hopes that similar advances in passive magnetic bearings may be possible. Passive bearings have the advantage of greater stability and reliability, and potentially lower parasitic loads than active bearings.

Two groups are leading the field in research on bearings: Boeing Corporation, and Lawrence Livermore National Laboratories. Boeing is better known for its airplanes and defense contracts than its flywheel technology, but the Boeing Phantom Works, the R&D branch of the company, has a flywheel program geared in part towards electric utility applications.

In 1998, the Department of Energy awarded Boeing a contract to develop flywheels with high-temperature superconductor (HTS) magnetic bearings. These bearings are made from superconducting materials that operate at somewhat higher temperatures than regular superconductors, although they still require cryogenic cooling with liquid nitrogen. The energy required to cool the materials is expected to be less than that required by conventional active magnetic bearings.

Using this technology, Boeing has built $15kW_{dc}$, 2.5 kWh energy-storage flywheels for both aerospace and utility energy storage applications. The flywheels have graphite composite rotors spinning in a vacuum. With further development, the company hopes to achieve 10kWh flywheels, and eventually develop megawatt-hour systems for utility energy storage applications [28,28].

It can be argued that modern flywheel technologies began at Lawrence Livermore National Laboratories (LLNL) in Livermore, CA, where Dr. Richard Post first proposed advanced flywheel systems for electric vehicles in the early 1970s. Later work at LLNL resulted in composite flywheels in place of the metal wheels predominant at that time. Much of LLNL's technology – particularly its Halbach motor/generator technology – was licensed to Trinity Flywheel Power (now a part of AFS Trinity).

LLNL's present work in flywheel technology is concentrated on the development of passive permanent magnetic bearings. Permanent magnets, arranged asymmetrically in such a way as to minimize instability and losses, can form stable room-temperature magnetic bearings. These bearings would enable much smaller standby losses than even HTS bearings, and would greatly increase the reliability and simplify the control systems of high-speed flywheels [30].

Composite Materials

Another area of intense interest to flywheel developers and manufacturers is the use of new composite materials in flywheel design. The term “composite material” is used to describe materials which have complex microstructures, often consisting of several materials in combination, and which defy classification by composition, crystal structure, or physical properties. The key point is that composites have a higher tensile strength and are lighter than steel. The expected benefit in flywheel applications is an order of magnitude increase in the practical wheel speed.

In the case of flywheels, the most common composite materials under consideration are graphite fiber composites and glass fiber composites. Both these materials are typically composed of fine fibers in a parallel arrangement, held together by a binder. This arrangement produces low-weight materials with very high tensile strength - often greater than that of steel - in the direction of the fibers. In flywheel applications, the lighter weight reduces the hoop and radial stresses within a spinning rotor at a given radial velocity, and the higher tensile strength allows a much higher maximum stress before yield. These effects combine to allow composite rotors to achieve much higher rotational speeds (and therefore, higher energy storage potential) than steel rotors.

At present, the specific research with respect to flywheels is generally dedicated to characterization, adaptation and qualification of new materials to a rotary application. Composite materials do not act linearly. As a result, they tend to be much more difficult to characterize and understand than materials such as steel. The adaptation of such materials to rotary applications can also be difficult. For example, fiber composite rotors cannot be cut out of a block of existing material; they must be constructed in such a way that fibers are wound around the circumference of the rotor, to absorb maximum stress. For these reasons, research into new rotor materials can be costly and time-consuming [32,33].

Research Activities

There are three major directions in flywheel rotor material research. The first is towards stronger, lighter materials, which allow higher rim speeds and energy density. The second is towards cost reduction of composite rotors. The third is towards more effective and more repeatable manufacturing techniques, producing safer and more reliable rotors. In general, all the material developments involve these three directions to some degree.

The Composites Technology Center at Pennsylvania State University in University Park, PA has concentrated its efforts in flywheel technology on the development of lighter, stronger, and cheaper composite rotors. Penn State investigators are working on perfecting a carbon filament winding system, which will improve the strength of rotors while allowing the use of cheaper carbon materials. They have also been involved in investigations into the use of exotic materials such as carbon filaments, carbon nanotubes, and higher temperature materials, all of which can improve flywheel performance in the future [6,32].

The University of Texas Center for Electromechanics in Austin, TX has focused on modeling and characterization as steps towards the development of a significant prototype project, a $2MW_{dc}$, 480MJ flywheel for the Advanced Locomotive Propulsion System (ALPS). University of Texas investigators have made significant progress into software modeling of the stress and dynamics characteristics of composite rotors. They have also developed new non-destructive characterization tools to understand performance of new materials and geometries. They are now investigating other effects on high-speed flywheels, such as the effect of thermal conditions, particularly in a near-vacuum environment, and behavior under non-standard conditions such as magnetic bearing failure [33].

Flywheel Demonstration Projects

Flywheels are extensively used as battery-less ride-through systems for critical loads at commercial and industrial sites. In addition, there have been a few notable large flywheel demonstrations which have attracted utility attention.

Flywheel Energy Storage Solution for Serving Fluctuating Loads (NYPA Case)

Flywheels are a proven technology for fast response and have excellent dynamic damping characteristics. When designed for power, the kW output rating can be quite high relative to their size and weight. When several flywheel modules are required to match the fluctuating load, paralleling is straightforward.

Electric service to light rail, subway trains, or trolley systems is an interesting application of this energy storage solution. Load fluctuations are related to electric trains starting up and stopping, with opportunity of demand reduction and energy recovery via regenerative braking. A practical case in point is a prototype installation in New York City, where NYPA has financed a flywheel energy storage system connected to the subway. The site is on New York City Transit (NYCT) premises. The installation is on Broad Channel, near the recently constructed bay equalizer site at the Far Rockaway Test Track, see Figure 13-12.

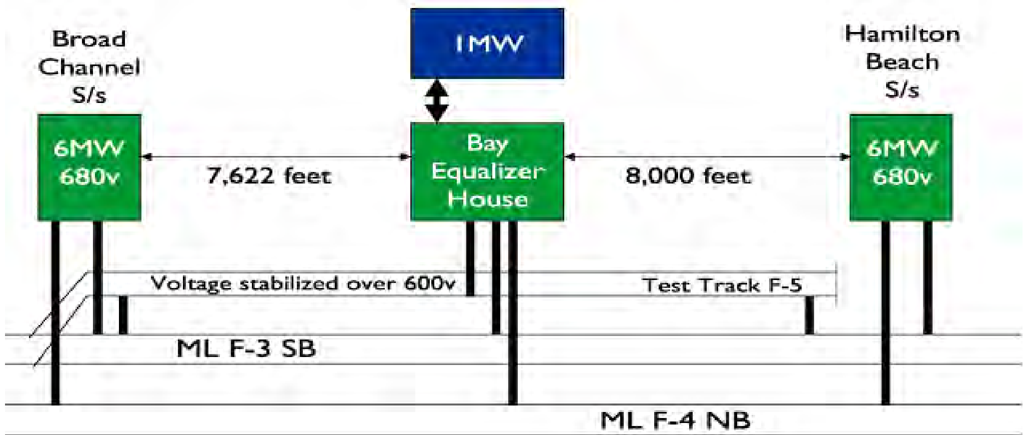

Figure 13-12
Two 6-MW Substations (NYPA) and 1MW Storage (NYCT) Service Far Rockaway Line

This site was selected so that power from the flywheel equipment may be utilized to support performance testing of new technology trains on the test track. Testing requires a stable track voltage, which has not been available at this site. As shown in Figure 13-13, average voltage is approximately 672 V_{dc} at light load, however excursions well above and below this level are common during train operations. The existing substation spacing along the Far Rockaway Line at Broad Channel makes the voltage requirements for performance testing ($600V_{dc}$ maintained) difficult to meet.

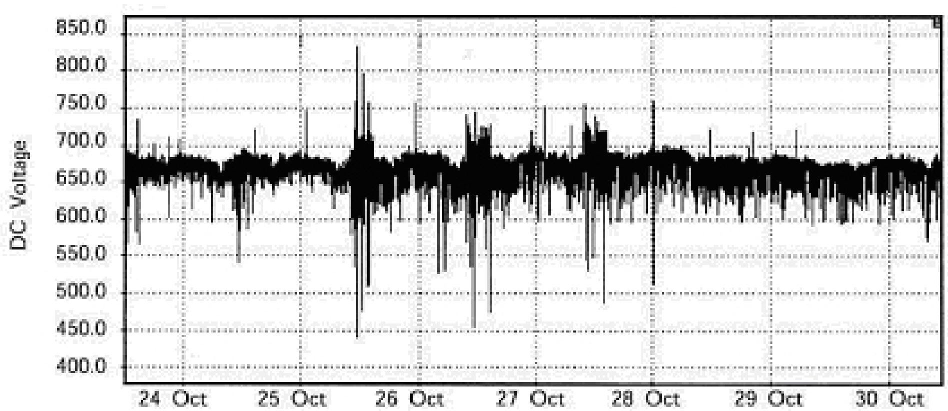

Figure 13-13
Typical Voltage Profile at the Far Rockaway Test Track in October 2001

The prototype installation consists of ten individual high-speed flywheels of 100-kw each, connected together to provide one-megawatt capacity, see photo in Figure 13-14. Together the flywheels store about 5 kWh in kinetic energy and could be expected to operate as often as every 2 minutes during peak 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 trains are regeneratively braking in the vicinity. Otherwise, the recharge is controlled based on track voltage during the several minutes between trains.

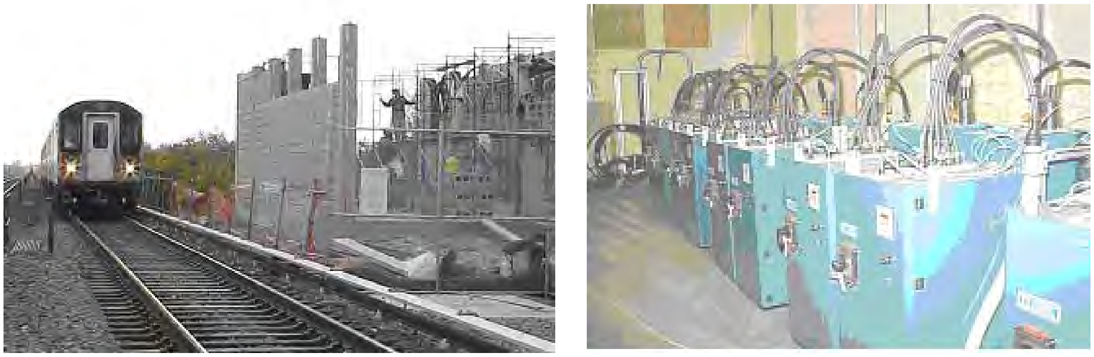

Figure 13-14
Flywheel Installation at NYCT Bay Equalizer Location, 10 100-kW Units in New Building

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. A typical power profile for this application, Figure 13-15, contains three distinct control regions: discharge, recovery and charge, and shows typical voltage levels for a no load situation.

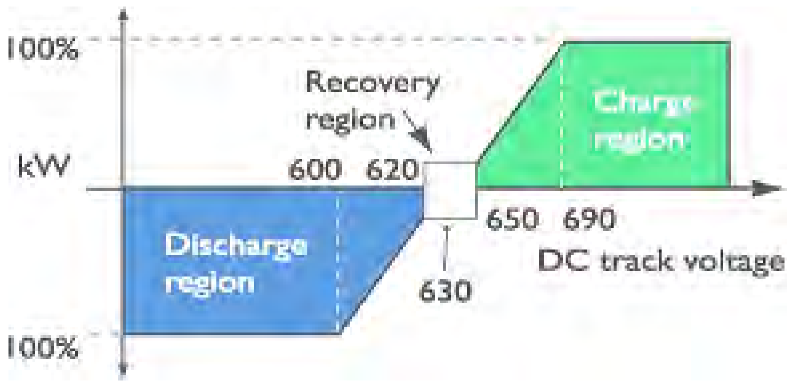

Figure 13-15
Typical Power Profile Based on a Nominal Track Voltage of $630V_{dc}$

Energy recapture depends on the coincidence of trains. In cases where trains in the vicinity are accelerating and braking at the same time, the energy is exchanged between trains and the flywheel is not cycled or is only partially cycled. From the above operating schedule, trains pass by approximately 10 times per hour over 6000 hours per year. If the flywheels recapture 15% of the time approximately 45,000 kWh are saved.

NYCT recognizes three distinct benefits from utilizing this kinetic energy storage system.

- Through proper parameter settings, improvement in the third rail voltage regulation is achieved. The flywheel output voltage is a constant voltage (for the duration of which the flywheels have power available to discharge). Thus, higher DC voltages may be realized during the short acceleration events (10 secs.) of trains, allowing operation of new more efficient AC trains.

- Cost savings in substation capacity and in NYTCs power bill are realized because peak power demand at neighboring substations is reduced by the timely contributions made from the energy storage equipment. Demand charges currently make up over 40% of electric cost. Estimated reduction at the two involved substations may be 33%.
- Energy savings from regenerative braking that would normally be dissipated in braking resistors and tracks during periods of non-receptivity may be stored and put to use later on by accelerating trains recapturing in the range of 7-25%.

For NYPA, the benefits are related to reduction in substation capacity, better utilization of existing T&D assets, and deferral of construction of new capacity for the new, higher power demand AC trains. This installation also provides a new design criterion for optimum placement of substations in traction applications. Application of the flywheel energy storage provides added flexibility in sub station placement, increased distance s between substations, and better utilization of available T&D investment dollars [24].

Similar systems have been installed in other locations, such as the South Ealing Test Track of the London Underground [23].

T&D System Energy Storage System Applications

Select Applications for Flywheel Energy Storage Systems

This section presents the select applications for which flywheels are suited and describes the key features of flywheel systems when configured to meet the select application requirements. Screening economic analyses have shown that flywheel systems are potentially competitive for some of the single function applications, but not any of the combined function applications, which are described in detail in Chapter 3. The following list briefly summarizes all of the Chapter 3 applications, with a reiteration of the key application requirements. Those for which flywheel systems are best suited are enclosed by borders.

Single Function Applications

Application A: Grid Angular Stability (GAS) – mitigation of power oscillations by injection and absorption of real power at periods of 1 to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 20 oscillatory cycles, cumulatively equivalent to a full power discharge (FPD) of 1 second duration; 1 event per day; 10 events per year. Valued at the cost of alternative solutions.

Application B: Grid Voltage Stability (GVS) – mitigation of degraded voltage by additional reactive power plus injection of real power for durations up to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 1 second FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application C: Grid Frequency Excursion Suppression (GFS) – "prompt" spinning reserve (or load) for mitigating load-generation imbalance. Requires energy storage to discharge real power for durations up to 30 minutes. The reference duty cycle for analysis is standby for infrequent events characterized by 15-minute FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application D: Regulation Control (RC) – system frequency regulation in concert with load following. The reference duty cycle for analysis is characterized by continuous cycles equivalent to 7.5-minute FPD and charge cycle (triangular waveform), 2 cycles per hour deployed with 10 minutes advance notice. Valued at market rates.

Application E: Spinning Reserve (SR) – reserve power for at least 2 hours with 10 minute notice. The reference duty cycle for analysis is standby for infrequent events characterized by 2-hour FPD, 1 event per day, 10 events per year. Valued at market rates.

Application F: Short Duration Power Quality (SPQ) – capability to mitigate voltage sags (e.g., recloser events). The reference duty cycle for analysis is standby for infrequent events characterized by 2 seconds FPD, 1 event per hour, 5 events per day, 100 events per year. Valued at the cost of alternative solutions.

Application G: Long Duration Power Quality (LPQ) – SPQ, plus capability to provide several hours reserve power. The reference duty cycle for analysis is standby for infrequent events characterized by SPQ plus standby for 4 hours FPD, 1 event per year. Valued at the cost of alternative solutions.

Application H: 3-hr Load Shifting (LS3) – shifting 3 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 3-hour FPD, 1 event per day, 60 events per year. Valued at market rates.

Application I: 10-hr Load Shifting (LS10) – shifting 10 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 10-hour FPD, 1 event per day, 250 events per year. Valued at market rates.

Combined Function Applications (In the Order Noted)

Application C1: Combined Applications C, A, B, D (GFS + GAS + GVS + RC)

Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR)

Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR)

Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR)

Application C5: Combined Applications I, D, E (LS10 + RC + SR)

Flywheel Energy Storage System Compliance With Application Requirements

The flywheel module performance parameters discussed above were used to develop approximate sizes and operational parameters for systems meeting the application requirements for the selected applications described in the previous section. Key factors in sizing flywheel systems include:

- Selection of the type of flywheel: high-energy or high-power. High-power flywheels are more appropriate for applications requiring short discharge durations, such as SPQ. High-energy flywheels are more appropriate for applications with longer discharge durations.
- Voltage: Output voltage is often programmable, since most flywheels have an AC-DC converter.

- Standby power requirements: Some flywheels have significantly larger standby losses than others. This is particularly true of the very large low-speed flywheels.
- Location: Larger flywheels are often cheaper from a capital cost standpoint, but require more space. Some flywheels require indoor space with environmental conditions. Others can be placed outdoors or even underground. Safety and environmental conditions should also be noted when siting a flywheel.

Performance aspects of flywheel energy storage systems for the selected applications are described below and summarized in Table 13-5. The reference power for all applications is 10 MW_{ac}. In these examples, representative flywheel products have been selected and sized for the application at hand. The selected product is one found to be appropriate for the particular application on the basis of technical and economic criteria. This does not mean, however, that other flywheel devices could not also perform the same function.

- Application A: Grid Angular Instability (GAS) – This application requires that the system continuously detect and mitigate power oscillations. Oscillations require that the system alternately inject full power for 1 second and then absorb full power for 1 second, ten times consecutively. In this application, the flywheel is assumed to only inject power, allowing full power to be dissipated with resistors during the absorption period. The energy storage would be composed of 22 Active Power CSDC 500 flywheel systems, each containing two flywheel systems optimized for $500W_{dc}$ output. The system would be attached to a Type III PCS with a pulse factor of 5. During most of the time the system would be at standby, with an efficiency of 97.3%. The lifetime of the flywheel is estimated to be 20 years.
- Application F: Short Duration Power Quality (SPQ) – This application requires that the system continuously detect and mitigate infrequent PQ events lasting 2 seconds. The energy storage would be composed of 22 Active Power CSDC 500 flywheel systems, each containing two flywheel systems optimized for 500W output. The system would be attached to a Type III PCS with a pulse factor of 5. During most of the time the system would be at standby, with an efficiency of 97.3%. The lifetime of the flywheel is estimated to be 20 years.

Table 13-5
Flywheel System Compliance With Application Requirements

Applications	Single Function: App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	Single Function: App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr
Energy Storage Selection		
Type of Product	Active Power CSDC 500	Active Power CSDC 500
Number of Strings	22	22
Pulse Factor	5.0	5.0
Max Charge Voltage	550	550
Min Discharge Voltage	550	550
Maximum DOD, %	100%	100%
Cumulative Cycle Fraction	0%	0%
Replacement Interval, yr	20	20
PCS Selection		
PCS Type (Chapter 5)	III	III
Duty Cycles		
Grid Support or Power Quality (GS or PQ)		
Power, MW	10	10
Event Duration, Hr	0.0003	0.0006
Load Shifting (LS)		
Power, MW		
Load Shift Energy, MWh/yr		
Load Shift Losses, MWh/yr		
Cycle Life Fraction		
Regulation Control (RC)		
Power, MW		
Hours per day, hr		
Days per year, days		
RC, MW-Hours/yr		
RC Losses, MWh/yr		
Cycle Life Fraction		
Spinning Reserve (SR)		
Power, MW		
SR, MW-Hours		
SR Losses, MWh/yr		
Cycle Life Fraction		
Summary System Data		
Standby Hours per Year	8,760	8,759
System Net Efficiency, %	97.3%	97.3%
Energy Storage Standby Efficiency, %	99.3%	99.3%
PCS Standby Efficiency, %	98.0%	98.0%
System Footprint, MW/sqft (MW/m^2)	0.0067 (0.0718)	0.0067 (0.0718)
Energy Storage Footprint, MW/sqft (MW/m^2)	0.0458 (0.4934)	0.0458 (0.4934)

Note: System net efficiency includes losses for energy conversion and system standby expressed on an annual basis, i.e., one minus inefficiency, where inefficiency equals the ratio of annual energy losses to the product of system rated power times 8760 hours, expressed in percent.

Benefit and Cost Analyses

Flywheel Energy Storage Pricing and Integrated System Costs

The prices of flywheel energy storage products vary somewhat with the size and maturity of the system. Some representative prices for various manufacturers have been collected here. Current nominal prices represent manufacturers' estimates on the basis of current production methods. Mature prices reflect savings due to economies of scale, rather than learning curve or improvements in technology.

Flywheel System	2006 Prices, $	Mature Prices, $
Active Power CSDC 500 ($500kW_{dc}$)	$88K	$75K
Pentadyne VSS-120 ($120kW_{dc}$)	$44K	$24K
Urenco PQT ($250kW_{dc}$)	$144K	$121K

The scope of supply of each of these flywheel products includes the rotor and related mechanical components, the motor/generator, and power electronics to convert the output to dc power.

The cost of integrated flywheel systems is obtained by combining the cost of the flywheel product scope of supply with the appropriate PCS and BOP costs as described in Chapter 5. The PCS and BOP costs shown in Table 13-6 are based on the methodology described in Chapter 5. Systems for short duration discharge applications (e.g., SPQ) use "discontinuous" IGBT-based PCS which accommodate high currents for brief periods at reduced cost compared to continuous ratings as described in Section 5.3. The cost of enclosures matches the requirement of the particular flywheel system, in accordance with guidelines specified in Chapter 3. The flywheels described here must be located in interior space with environmental control. The cost for this space is included at $100/sqft.

Table 13-6
Capital and Operating Costs for Flywheel Systems

Applications	Single Function	
	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr
Energy Storage Capacity, MWh_{ac}	0.003	0.006
PCS Initial Cost, $/kW	153	153
BOP Initial Cost, $/kW	100	100
Energy Storage Initial Cost $/kW	206	206
Energy Storage Initial Cost $/kWh	740,000	370,000
Total Capital Cost, M$	4.6	4.6
O&M Cost – Fixed, $/kW-year	18.4	18.4
O&M Cost– Variable, $/kW-year	9.1	9.1
NPV Disposal Cost, $/kW	0.0	0.0

Note: The total initial cost may calculated in two ways:
1. By mutiplying the sum of PCS, BOP and flywheel initial costs expressed in $/kW by the reference power,
2. OR by mutiplying the sum of PCS and BOP expressed in $/kW by the reference power and then adding the product of flywheel initial cost expressed in $/kWh and the flywheel capacity

Fixed O&M costs are based on $2/kW for the PCS as required by provisions in Chapter 5, plus flywheel product maintenance in accordance with the vendor. For the Active Power CSDC 500 product, the maintenance program consists of the following:

- Quarterly replacement of intake air filter
- Yearly oil change
- Replace bearings every 3 years

The yearly service contract sold by Active Power covers the cost of all maintenance and parts, including 1 bearing change every 3 years. A standard service contract of this type is sold for $3,300 per year. A more extensive service contract, which includes off-hour visits, is available for those requiring 24-7 service, for $3,500 per year. In addition, an allowance for annual property taxes and insurance, based on 2% of the initial total capital costs, is included in the fixed O&M costs.

Variable O&M costs for all flywheels are based on the cost of electrical losses to maintain the PCS during hot standby intervals, and to cover all parasitic and intrinsic losses in the flywheel product. Flywheel systems do not contain exotic materials and do not require special disposal. In general, the scrap value of the various components will not exceed the cost of disposal.

Lifecycle Benefit and Cost Analysis for Flywheel Systems

Further insight to the value of energy storage can be gained through lifecycle cost analyses using a net present value (NPV) methodology and comparison with alternatives. The financial parameters in Table 13-7 are used to assess the applications described in the preceding sections and the assumed electricity rate structure is presented in Table 13-8.

Table 13-7
Financial Parameters

Dollar Value	2003
System Startup	June 2006
Project Life, years	20
Discount Rate (before tax), %	7.5
Property Taxes & Insurance, %/year	2
Fixed Charge Rate, %/year	9.81

Table 13-8
Electric Rates

Load Shifting On Peak Period	3	10
Number Cycles per year	60	250
On-Peak Energy, $/MWh	120	80
Off-Peak Energy, $/MWh	20	
Yearly Average Energy Charge, $/MWh	38	
Regulation Control, $MW-Hour (power), $/MWh	16	
Spinning Reserve, $MW-Hour (power), $/MWh	3	
Transmission Demand Charge, $/kW-mo	5	

The results of lifecycle cost benefit analyses of select flywheel applications are summarized in Table 13-9 and discussed below. The bases and methodology used in valuing energy storage applications is described in detail in Chapter 4. The details of the cost benefit analysis for each application are discussed below.

Table 13-9
Summary of Benefit and Cost Analyses of Flywheel Systems

Applications	Single Function	
	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr
Alt Solution Value, $/kW	750	1,000
Initial Installed Cost, M$	4.59	4.59
Total Costs, M$	(7.4)	(7.4)
Total Benefits, M$	7.50	10.0
Benefit to Cost Ratio	1.01	1.35
NPV, M$	0.1	2.6
Energy Storage Module	Active Power CSDC 500	Active Power CSDC 500
Number of Modules	22	22
Energy Storage 2006 Price, K$/module	88	88
Energy Storage Price for NPV=0, K$/module	92	187

- Application A: Grid Angular Stability (GAS) – This application was evaluated on the assumption that an alternative system capable of mitigating GAS events can be obtained for capitalized acquisition and operating costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 13-9, this application yields a NPV of $0.1 million for an initial investment of about $4.6 million. As a measure of the sensitivity of NPV with respect to alternative system costs, Figure 13-16 illustrates the change in NPW over a range of $500 to $1000/kW, and shows that flywheel systems will compete against alternative solutions with net capitalized costs in excess of about $740/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of flywheel system were increased from $88 to $92 thousand per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $750/kW.

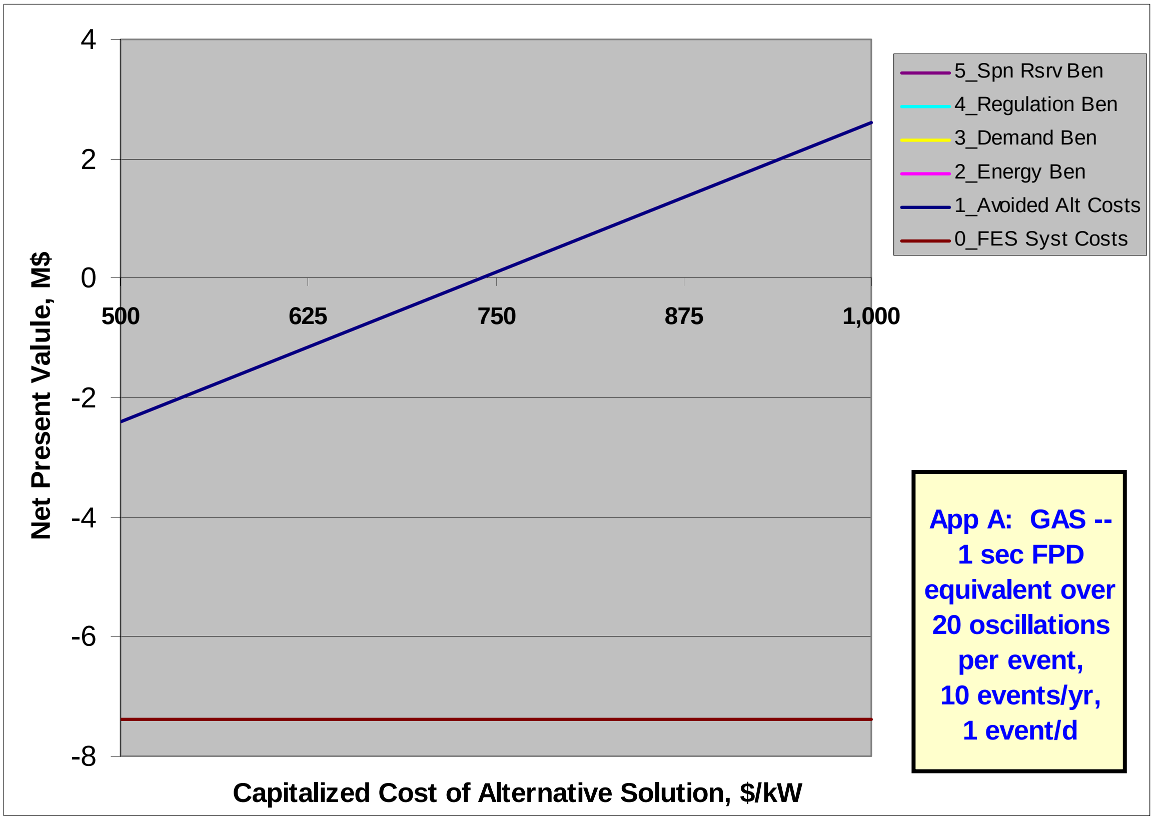

Figure 13-16
Application A: Flywheel System NPV vs Cost of Alternative System

- Application F: Short Duration Power Quality (SPQ) – This application was evaluated on the assumption that an alternative system capable of mitigating SPQ events can be obtained for capitalized acquisition and operating costs of about $1000/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 13-9, this application yields a NPV of $2.6 million for an initial investment of about $4.6 million on this basis. As a measure of the sensitivity of NPV with respect to alternative system costs, Figure 13-17 illustrates the change in NPV over a range of $500 to $1500/kW and shows that flywheels will compete favorably against alternative solutions with net capitalized costs in excess of about $740/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the flywheel system were increased from $88 to $187 thousand per 500kW unit, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $1000/kW.

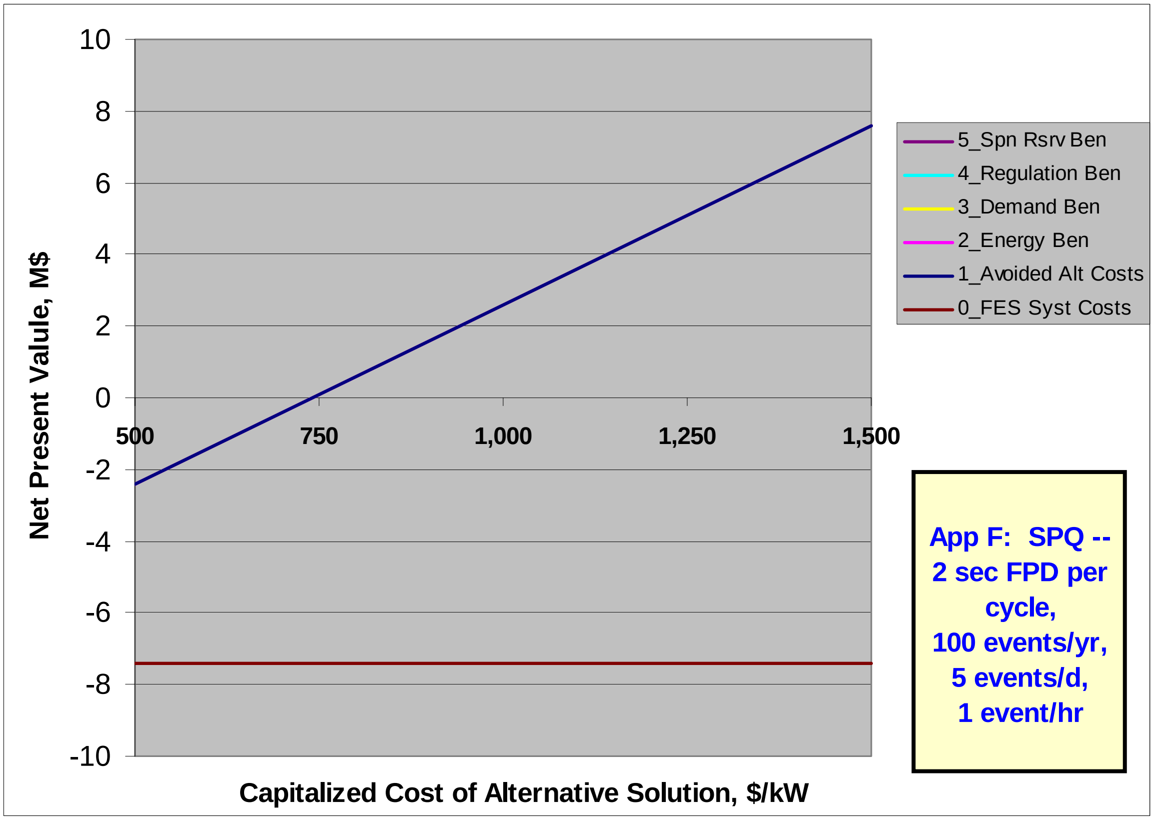

Figure 13-17
Application F: Flywheel System NPV vs Cost of Alternative System

Interpreting Results From Benefit-Cost Analyses

In general, flywheel battery systems are expected to be competitive in some single function applications at present. They may become attractive investments for the combined function applications in the future.

The reader is reminded that the foregoing analyses are intended as a guide to the initial consideration of energy storage options, and that these analyses are based on representative electric rates and costs for alternative systems as described in Chapter 4. The assumptions used herein should be reviewed in light of project specific applications, alternative solutions, electric rates and financial parameters.

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14
ELECTROCHEMICAL CAPACITORS

Introduction

Discovered by Henrich Helmholtz in the 1800s, electrochemical capacitors were first practically used in 1979 for memory backup in computers and are now manufactured by many companies. Electrochemical capacitors are distinguished from other types as "double-layer capacitors[20]." Manufactured products have also been given names including "super," "ultra," "gold," "pseudo," as well as "electric double-layer" capacitors.

Double layer electrochemical capacitors differ from other types by having capacitance and energy density values several orders of magnitude larger than even the largest electrolytic-based capacitor. They are true capacitors in that energy is stored via electrostatic charges on opposing surfaces, and they can withstand a large number of charge/discharge cycles without degradation. They are also similar to batteries in many respects, including the use of liquid electrolytes, and the practice of configuring various size cells into modules to meet power, energy, and voltage requirements of a wide range of applications.

The first products were rated at two to five volts and had capacitance values measured in fractions of a Farad to several Farads. Although early applications were primarily computer memory backup, the technology has evolved to larger scale applications. Today's devices range in size up to hundreds of thousands of Farads at low voltage and, in some applications, systems voltages (multiple series-connected capacitors) are above 600 V. The technology has grown into an industry with an annual sales estimated to be $100 million. It is poised for rapid growth in the near future with higher energy and higher voltage devices suitable for power quality and advanced transportation applications. With the advent of distributed power generation, capacitors are being considered for fuel cell and micro-turbine load inrush support, and for leveling fluctuating energy flow from natural sources like wind turbines or solar.

[20] There is some uncertainty within the industry on the exact name for capacitors with massive storage capability. This is in part due to the many names of products by different manufacturers, but also due to the relative newness of the industry and recent advances. An electrochemical capacitor commonly stores energy through non-faradic processes (electrostatic). However, faradic processes (electron transfer due to chemical or oxidation state changes) can and do occur. Because both processes can occur, the generic term electrochemical is more appropriate than double-layer electrochemical capacitor, which also excludes the mixed-metal-oxide capacitor technology. In general, this report uses the generic term electrochemical capacitor as suggested by A. Burke and endorsed by B. Conway and J. Miller.

Description

Capacitor Fundamentals

A capacitor is a device used for storing electrical charge. There are three distinct types of capacitors: electrostatic, electrolytic, and electrochemical. The simplest capacitor is a parallel-plate electrostatic. It has two conductors of area *A* separated by a distance *t*. The region between the plates is usually filled with air, paper or other dielectric material, which increases the stored energy in the device. The charge, *Q*, that is stored in the device, is proportional to the voltage applied to the conductors. This proportionality constant is the capacitance. The capacitance C is equal to the dielectric constant times the area divided by the separation.

The energy E, that is stored in an ideal capacitor at voltage V, is equal to:

$$E = 0.5\ CV^2 \qquad \textbf{Eq. 14-1}$$

The energy increases as the square of the applied voltage. When charged at a constant current, the voltage of an ideal capacitor rises linearly with time. When charged at a constant power, the stored energy rises linearly with time. In reality, the first order model of a capacitor is a series combination of an inductor, a resistor, and a capacitor. The fundamental equations for all types of capacitors are summarized in Table 14-1. Note that R_s, the series resistance, is also referred to as the equivalent series resistance, ESR.

Table 14-1
Fundamental Equations for Capacitors

Stored Charge, Q	Q = CV	C = capacitance
Stored energy, E, ideal case	$E = ½\ CV^2$	V = applied voltage
Capacitance of parallel plate capacitor, C	C = εA/t	ε = dielectric constant A = area of the capacitor plate t = separation of the plates
Self-resonant frequency, f_o, for RLC circuit	$f_o = \frac{1}{2\Pi\sqrt{LC}}$	L = inductance
Maximum power, P_{max}	$P_{max} = V^2/4R_s$	R_s = series resistance (ESR)
Resistive charge or discharge efficiency, η	$\eta = \frac{R_L}{R_L + R_S}$	R_L = load resistance
Constant current charge or discharge efficiency, η	$\eta = \frac{(V_r - I_o R_S)}{(V_r + I_o R_S)}$	V_r = rated voltage I_o = fixed current

For most practical applications in the utility industry, the inductance in the series-RLC circuit can be ignored because operation is well below the self-resonant frequency. Thus, a simple series-RC circuit is a good first-order model for the real capacitor.

It is important to understand the effect of the capacitor internal resistance (R_s) on the efficiency of discharge. For example, modeling the capacitor as series-RC circuit being discharged into a resistive load R_L the efficiency of discharge in percent is equal to $100R_L/(R_S + R_L)$. Thus the efficiency is nearly 100% when the load resistance, R_L, is much greater than the internal resistance, R_S. On the other hand, the efficiency is exactly 50% for the matched load, that is when $R_L = R_S$. One-half the delivered energy is dissipated in the capacitor itself and not in the load. Similar efficiency relationships can be calculated for constant current charge or discharge, as listed in Table 14-1.

Electrochemical Capacitor Characteristics

What Is a Double-Layer Capacitor?

Electrochemical capacitors consist of two electrodes, a separator, electrolyte, two current collectors, and packaging. Within the electrochemical capacitor, charge is stored electrostatically, not chemically as in a battery. It has, as a dielectric, an electrolyte solvent, typically potassium hydroxide or sulfuric acid or an organic liquid, and is actually two capacitors connected in series via the electrolyte. It is called a *double-layer capacitor* because of the interface region of the electrolyte at each electrode as shown in Figure 14-1.

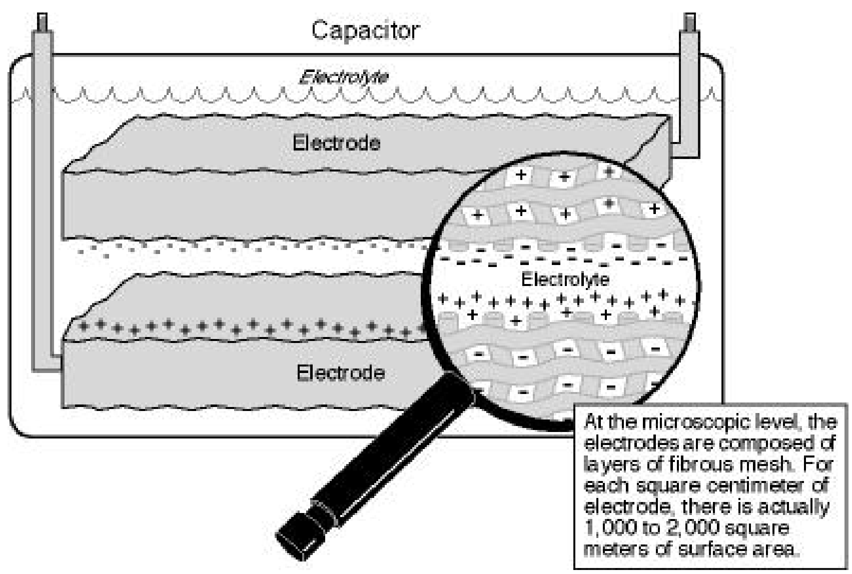


Figure 14-1
Construction of a Flooded Electrochemical Capacitor

As in any capacitor, the amount of capacitance is directly related to the surface area of the electrode. Carbon is the element almost uniquely suited for fabrication of electrodes within electrochemical capacitors. It has high electronic conductivity and is available at reasonable prices from many sources. The surface area of a carbon electrode is very large at 1000 to 2000 m^2/cm^3. This large surface area is the reason for very high characteristic capacitance and energy density.

Evolution of Double-Layer Technology

Electrochemical capacitor technology has evolved through four distinct design types, each with its own development time line. Symmetric designs, in which both positive and negative electrodes are made of the same material with approximately the same mass, are available with aqueous or organic electrolytes. Asymmetric designs have different material for the two electrodes, with one of the electrodes having much higher capacity than the other. The asymmetric are currently available with aqueous electrolytes and the asymmetric organic electrolytes are in development. There are significant differences in the characteristics and performance of these four types leading to a wide range of products with many different possible applications.

The first devices, type I, use a symmetric design with activated carbon for the positive and negative electrodes, each with approximately the same mass and similar capacitance values. The choice of electrolyte is an aqueous solution, usually high-concentration sulfuric acid or potassium hydroxide. Because of the aqueous electrolyte, operating voltages are limited to ~1.2 V_{dc} per cell, with nominal ratings of 0.9 V_{dc}.

Second to come along was a type II electrochemical capacitor that is similar to the first, but with an organic rather than an aqueous electrolyte. The organic electrolyte typically is an ammonium salt dissolved in an organic solvent such as propylene carbonate or acetonitrile, which allows operation at higher unit cell voltages. Type II products are the most common type in use today and are rated at voltages in the range of 2.3 to 2.7 V_{dc}/cell, depending on the manufacturer.

Operation at higher voltages offers distinct advantages for energy and power density, but with some offsetting disadvantages. The dielectric constant of the organic solvent is less than that of water; the double layer thickness (plate separation) is greater because of the larger solvent molecules; the effective surface area of the electrode is somewhat diminished because the larger ion sizes cannot penetrate all pores in the electrodes; and the ionic conductivity of the electrolyte is much less than that of aqueous electrolytes, particularly at low temperatures. Stable, long term operation at higher voltages requires extremely pure materials: trace quantities of water in the electrolyte, for instance, can create problems. Thus, the device must be packaged in such a way that water does not enter the capacitor.

The net effect of using an organic electrolyte in the type II device is increased energy density over type I. However, there often is a reduction in power performance over that exhibited by the type I devices, even though each cell operates at higher voltage.

The type III design, referred to as asymmetric, is the most recent available. They are comprised of two capacitors in series, one being an electrostatic capacitor and the other a faradaic pseudocapacitor. The electrostatic capacitor is exactly like those used in the symmetric type I and II devices. It consists of a high-surface-area electrode with double layer charge storage. The faradaic-pseudocapacitor electrode relies on an electron charge transfer reaction at the electrode-electrolyte interface to store energy. This is very similar to an electrode in a rechargeable battery.

In this design the capacity of the faradaic-pseudocapacitor electrode is typically many times greater than the capacitance of the double layer charge storage electrode. Thus the depth of discharge of the faradaic-pseudocapacitor electrode is very small during operation, allowing higher cycle life. Different asymmetric capacity ratios have been built to tailor the capacitor for specific applications. Asymmetric electrochemical capacitors having aqueous electrolytes have an important advantage of voltage self-balancing, which will be discussed in the section on series connecting cells to create high-voltage systems. None of the other types of capacitors offer this feature.

Comparison of the three product types is provided in Table 14-2.

Table 14-2
Comparison of Functionality of Electrochemical Capacitor Designs

Electrochemical Capacitor Types	Type I Symmetric /aqueous	Type II Symmetric /organic	Type III Asymmetric /aqueous
Energy density	Low to moderate	Moderate to high	High to very high
Power performance	High	High	Low to high
Cycle life	High	High	High
Self-discharge rate	Low	Low	Very low
Low-Temp. performance	Excellent	Good to Excellent	Excellent
Packaging	Non-hermetic	Hermetic	Non-hermetic, resealable vent valve
Voltage balance	Resistor/Active	Resistor/Active	Self limiting/Active
Cell voltage	$< 1\ V_{dc}$	$2.3 - 2.7\ V_{dc}$	$1.4 - 1.6\ V_{dc}$

A type IV electrochemical capacitor is currently not available in a commercial product, however there are active research programs directed toward development of such devices. These devices use an asymmetric design with an organic electrolyte. This combination provides the opportunity for the faradaic-pseudocapacitive charge storage with the higher operating voltage afforded by the organic electrolyte. For example, the design could mate an electrostatic electrode with a faradaic pseudocapacitive electrode that operates by intercalation, similar to one electrode in a lithium ion battery. Or, there could be charge storage in an electrochromic polymer such as a polythiophene. There are many faradaic electrode materials that can be used with the double layer electrode, again using a large capacity ratio as previously described to obtain high cycle life.

Double-Layer Technology Comparisons

Table 14-2 compares some general properties of each type capacitor. Type IV products are not described because of their present early state of development. As listed, type I products have low to moderate energy density, type II products have moderate to high energy density, and type III products have high to very high energy density. Power performance can be very high for type I products because of the use of high-conductivity aqueous electrolytes. Type II products can be high in power, and type III products, depending on optimization, can be low to high.

Cycle life can be high for all types of capacitors. Self-discharge rates for type I and II designs are generally low, unless they use balancing resistors. These resistors are included to help maintain voltage uniformity in series-strings of cells. The self-discharge rate of the type III capacitor is very low, usually less than a commercial lead-acid battery.

Temperature performance is excellent for type I and type III designs because of the low freezing points of the sulfuric acid or potassium hydroxide solutions used for the electrolyte. The low temperature performance of type II capacitors depends intimately on the exact solvent used in the electrolyte and cell design details. Performance can be good to excellent.

Packaging of the different type products varies considerably. Two of the commercial type I capacitor products use bipolar construction, which involves sealing a stack of series-connected cells using a potting material around the stack perimeter. The stack is then placed within an epoxy or metal package. Type II products invariably are well sealed, often using a hermetic design that involves welded metal packaging with glass-to-metal seals. Because this package is completely sealed, it usually contains a rupture valve that is designed to burst at a specified overpressure condition. This is used to prevent the cell from exploding due to internal gas generation during abuse situations. The use of a rupture valve in the hermetic packages should be mandatory for safe operation of these devices.

The type III product is a single cell design with a plastic package similar to that of an aircraft nickel cadmium battery. The cell is not hermetically sealed, but has a resealable safety valve to permit gas release during severe over-voltage conditions.

Voltage balance for a series string of capacitor cells can involve active or passive systems. A passive system is generally a parallel string of resistors attached to the capacitor string at each cell. The active systems include cell voltage monitoring and in some cases forces individual cells to charge or discharge and bring voltage uniformity to the string. Type III electrochemical capacitors have natural voltage balancing when connected in a series string. This is due to several reasons, one being that the device can operate on an oxygen cycle just like sealed lead-acid or NiCd batteries. A second reason is that the electrolyte has a well defined, essentially fixed decomposition potential. So, it is very difficult to over-voltage a type III cell.

Cell operating voltage for a type I device is generally $<1\ V_{dc}$. For type II devices, it presently is 2.3 to 2.7 V_{dc} and is expected to increase to perhaps 3.0 V after further developments. Type III devices presently are comprised of a nickel oxyhydroxide positive electrode mated with an activated carbon negative electrode. This system operates at between 1.4 V_{dc} and 1.6 V_{dc} per cell, depending on the optimization of the device. Type IV designs have voltages reported to exceed 4 V_{dc} for some material systems.

Asymmetric capacitor designs have led to higher energy densities and symmetric designs usually have higher peak power. Today's types I and II electrochemical capacitors are in the 1 to 5 Wh/kg range. Commercial capacitors of the type III design are available with energy densities of 10 Wh/kg. Energy densities as high as 19 Wh/kg are reported in patent examples covering this technology. In comparison, lead-acid batteries have an energy density in the range of 25 to 45 Wh/kg depending on design.

Electrochemical Capacitor Construction

The carbon electrodes used in both symmetric and asymmetric electrochemical capacitors consist of a high-surface-area activated carbon having area on the order of 1000 m^2/g or more in particulate or cloth form. The carbon electrode is in contact with a current collector. A material that prevents physical contact (shorts), but allows ion conduction, separate the electrodes. One design for type II products utilizes particulate carbon in a spiral-wound configuration. Such construction can be performed on a high-speed winding machine, which introduces minimal labor content. While this construction lends itself to a right-cylinder product, it can also form rectangular packaging. This form factor is more desirable in some applications. Type III electrochemical capacitor cells are constructed in a similar fashion to aircraft NiCd battery products. The first commercial products used a nickel-oxyhydroxide positive electrode with an activated carbon cloth negative electrode.

The electrolyte of an electrochemical capacitor is an important constituent. Properties most desired include high conductivity and high voltage stability. Little can be done to change the conductivity and voltage characteristics of aqueous-based electrolytes used in type I or type III products, but major improvements should be possible for type II products. Higher-conductivity electrolyte yields increased power performance, and high voltage stability allows stable operation at high voltage. These properties are important for energy and power since each measure scales as the square of the voltage. Organic electrolytes allow operation above two volts, the exact upper limit depending on the solvent and salt, their levels of purity, the desired operating temperature, and component design life.

The electrolyte in a type II capacitor is one of its more expensive constituents. It must have low concentrations of water at the time of manufacture and over the life of the product. This adds manufacturing costs in addition to material costs. Type II electrolytes are generally comprised of an ammonium salt with a solvent such as propylene carbonate, dimethyl-carbonate, or acetonitrile. At the present time, acetonitrile is the most popular solvent in large capacitors. It offers higher power operation, but at the expense of using a toxic and flammable material.

One feature common to all electrochemical capacitors is the requirement that some pressure be applied to the cell so that its electrodes remain in contact with the separator, that the electrodes are in contact with the current collectors, and that everything is wetted with electrolyte. The amount of pressure required depends on the design and electrode form. Winding pressure is typically used for type II products. External pressure plates are usually used for type I and III products.

Performance Features and Limitations

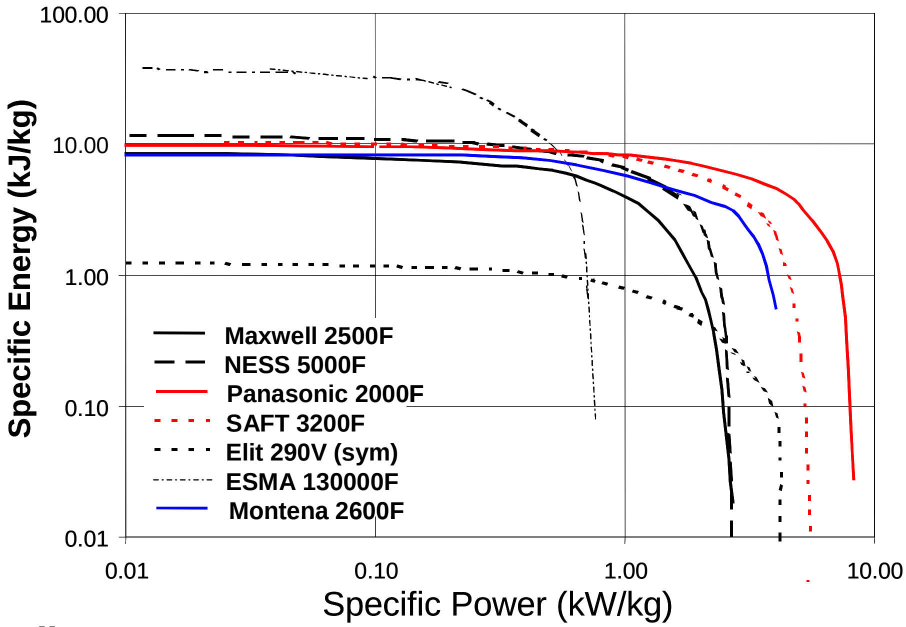
Power-Energy Relationships (Ragone Plots)

A convenient way to compare various energy storage technologies is to use so called Ragone plots. These plots show energy available (work performed) as a function of power level. Relative units for energy and power are used such as specific energy in Wh/kg or power density in kW/ liter. At low power levels essentially all of the energy is available to perform work. Less energy is available as the power level increases, until a maximum power value is reached.

This behavior is typical for all sources of energy and is therefore useful for comparison purposes. For example, a horse that is walking (at low power output) can likely perform more work until fatigue than one that is running (at high power output). This behavior is true for capacitors. More energy is released at slow discharge rates than at faster rates. Losses increase and efficiency drops off significantly at high rates thus reducing the amount of energy that can be delivered in any particular application. The Ragone plots are particularly useful for matching application requirement with various energy storage technologies. When using Ragone plots it is important to keep in mind that attributes other than power and energy such as cycle life, self-discharge rate, operational life and safety are not considered. These other factors may also be key to selection of the best technology for a particular application.

Ragone Plots for Available Capacitors

There are many ways to compare capacitor products. One way is to examine their power-energy behavior. Figure 14-2 shows Ragone plots of several large electrochemical capacitors available as commercial products or as fully packaged prototype products. Most of the devices were tested as single cells. However, the ELIT was tested as a multi-cell module rated at 290 V_{dc}. The operating voltage window was from rated voltage *Vr* to one-half rated voltage, which represents 75% of the stored energy in an ideal capacitor.



Notes:
1. Calculated using equivalent circuit models and voltage window of V_r to 0.5 V_r
2. Module and cell voltages vary, Elit 290 V, ESMA 1.6V, others are rated at 2.3 - 2.7 V
3. Montena has since been acquired by Maxwell

Figure 14-2
Energy and Power Relationships for Several Large Electrochemical Capacitors (i.e., Ragone Plots)

As shown in, Figure 14-2 at low power levels, different capacitors types tend to group, depending on their design. For instance, energy performance at low power of the type II capacitors are all approximately 10 kJ/kg (3 – 4 Wh/kg). The type I (Elit) capacitor is at a lower energy value of ~1 kJ/kg (~0.3 Wh/kg). The type III (ESMA) capacitor is at a higher level ~35 kJ/kg (~10 Wh/kg). This type III is a "traction" type capacitor, which has been optimized for high-energy density applications. Note that the type I capacitor is rated at 290 V_{dc} and is comprised of hundreds of cells connected in series. This product uses bipolar construction as opposed to individual cell construction. The voltages of individual cells in the series stack have been de-rated in this unique high voltage module. Similarily, type II cells would also need to be derated when series-connected.

On the other hand, capacitor power performance is not well grouped, but widely spread. For the type II capacitors, this suggests that these commercial devices have different types of carbons with different electrode thickness. The electrolyte for all of these type II capacitors is believed to be acetonitrile based. Even with the larger mass and volume required to achieve the higher voltage rating, the type I capacitor shows good specific power and power density, albeit at lower energy density and specific energy.

The asymmetric capacitor design can offer energy density advantages over symmetric designs, as explained under Operating Principles below. Another advantage of an asymmetric capacitor is that it can reliably operate above 1.2 V_{dc} (the breakdown voltage of water) without gas evolution, even when employing an aqueous electrolyte. Operation above 1.2 V_{dc} is possible because reaction kinetics for gas evolution are slow. Therefore available asymmetric capacitors products can operate at 1.4 to 1.6 V_{dc} for the same reason lead-acid batteries can operate at 2.05 V_{dc} per cell with an aqueous electrolyte.

Pulse Ragone Plots

For many applications, it is useful to determine the energy delivered by a capacitor during a given discharge time. This relationship, for instance, can express the energy delivered by a capacitor during one 60 Hz cycle. In this case, the effective energy density of the capacitor has to be measured at the pulse width of one cycle. Figure 14-3 is pulse discharge data for several large electrochemical capacitors. The discharge is from rated voltage to 90% of rated voltage, and the pulse lengths are from very long, 100 s, down to 1 ms. This plot shows the energy per mass that can be delivered by the capacitor for different length pulses.

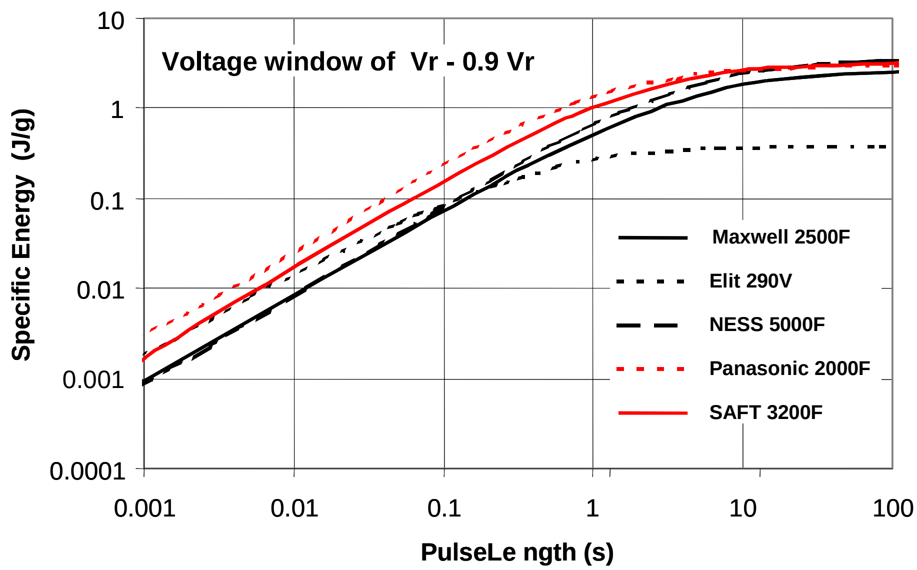


Figure 14-3
Pulsed Ragone Plot for Several Large Electrochemical Capacitors

As shown in this figure, several of the capacitors have an effective specific energy of approximately 3 J/g for long pulse lengths. At shorter pulse lengths, for example at 1s, the effective energy drops by a factor of three or more per decade for the majority of these capacitors. The effective energy density continues to drop as the pulse length becomes shorter. This behavior is characteristic of a multiple-time-constant circuit as exists with electrochemical capacitors. The shape of the curve depends on the capacitor design. It is possible to design the capacitors for either higher long pulse length or higher short pulse length performance. It is not possible to predict the energy delivered by a capacitor at short discharge times based on total specific energy alone.

Temperature Performance

Electrochemical capacitors provide good operating performance over a wide range of temperatures. Upper temperature limits are generally below 85 C, depending on the product. Lower temperature limits are as low as -55 C in some products. Capacitor properties, in particular leakage current, are affected by temperature. Property changes observed with increased temperature are fully reversible if the temperature is not excessive. Self-discharge rates increase dramatically with temperature and often establish a practical upper operating temperature limit. Correspondingly, product life decreases at high temperatures since mechanisms responsible for the leakage current are often chemical side-reactions.

Such undesired chemistry in type II capacitors results from electrochemically active impurities that were originally present in the package (water, for instance), and new impurities that are created during capacitor operation due to electrolyte decomposition or arise from permeation into the package through seals. One common method to counteract the elevated leakage current levels and thus increase operating life of type I and II cells is to reduce the average voltage applied to a cell. This reduces the effective energy density of the capacitor but can substantially increase operating life.

Exceptional low-temperature performance can usually be expected in all electrochemical capacitors. This is possible because, unlike batteries, reaction kinetics do not limit the charge or discharge rate of an electrochemical capacitor. Instead, the limit is usually established by the electrolyte conductivity. Thus, capacitors can operate with good performance at very low temperatures. Generally, but not always, aqueous electrolyte electrochemical capacitors (types I and III) have the least change in performance at low temperatures compared with room-temperature values.

Combining Cells Into Modules

Unlike conventional electrostatic and electrolytic capacitors, electrochemical capacitors are inherently low voltage devices. The maximum voltage of a single cell in a commercial product is 2.7 V_{dc}. Thus, to meet the 600- to 800-V_{dc} requirements of a utility application, hundreds of cells are series-connected and a DC-to-DC boost converter may also be employed.

Failure of just one cell in a series string can lead to failure of the entire storage system. A cell can fail as an open circuit or as a short circuit. The most common failure is an open circuit. Of course, if the failure is an open circuit, the entire system will stop working. On the other hand, if a single cell short circuits, then other cells in the string will experience higher voltage, which may stress them. This stress could lead to accelerated aging of those remaining and premature failure of another cell, and so on. Thus, one cell failure in this scenario could start a cascade situation where the entire string of cells would rapidly become a short circuit.

For long life, each cell in a series-string must remain below its maximum voltage rating under all conditions, which includes charge/discharge as well as float operation. The three key parameters affecting the cell voltage are variability in capacitance, internal resistance, and leakage current. Each of these parameters can lead to voltage imbalance among cells in a string. Thus, the construction of the cell, and its normal variability, will affect the reliability of a high-voltage string.

Cell Over Voltage in a Series String

Preventing cell over voltage is critically important for type I and II symmetrical capacitors. When gas is generated due to over voltage in a symmetric electrochemical capacitor there is no means for recombination and pressure rises inside the package. Some small capacitors have crimp seals for pressure relief that can vent small amounts of gas, eventually leading to dry-out and failure. Hermetically sealed packages may swell as the pressure rises and the package can eventually rupture causing a catastrophic loss of electrolyte and failure of the cell, usually as an open circuit. Before total failure these conditions may cause additional voltage stress on the remaining cells and lead to unusual performance of the series string.

Voltage de-rating, decreasing the average cell voltage in the string, is often applied as an effective way to avoid cell overvoltages. That is, the average voltage, V_{ave}, on each cell in the string must be below its maximum allowable value. This means the number of cells connected in series need to operate at voltage V must be greater than V/V_{ave}. As described, this will prevent a single cell in the string from reaching the maximum voltage and causing problems. The resultant effect is lower power (more cells in series means higher series resistance), less energy storage (more cells means less capacitance), and higher cost.

The type III asymmetric are more tolerant to overvoltages. In this case the recombinant mechanism seen in some aqueous batteries[21] helps to maintain voltage balance in a series string. When the string is charged with a controlled current, cells that first reach over-voltage conditions start to evolve oxygen. They do not rise in voltage while the lower charge cells “catch up.” For healthy cells this condition continues until all of the cells reach full voltage. Provided the rate of oxygen generation is not too high compared to the rate of gas recombination, there is practically no loss of electrolyte. Therefore, type III electrochemical cells have a valuable self-leveling characteristic.

Like recombinant batteries, these devices can operate at a slight overpressure and normally release no gas. Nevertheless, commercial products have a pressure release safety valve similar to that used on batteries. At higher over voltage conditions, there can be gas releases with consequential loss of electrolyte, but without damage to the cells. Because of the valve there is generally no swelling of the cells and no deterioration in performance. If overvoltage conditions continue and lead to excessive consumption of electrolyte, then the cell will fail as an open circuit due to electrolyte loss.

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[21] There is a similarity between aqueous batteries and asymmetric electrochemical capacitors. Such rechargeable batteries can be subjected to conditions that might lead to over voltage, but they do not actually rise in voltage. Instead, the high voltage causes the evolution of oxygen gas at the positive electrode of the cell. The gas travels to the negative electrode and recombines to form water. This mechanism is used in recombinant lead-acid batteries as well as in sealed nickel cadmium and sealed nickel metal hydride batteries.

Type III capacitors differ from type II devices with respect to cell voltage de-rating. In fact, it is undesirable to de-rate the voltage of an asymmetric aqueous capacitor. It is best to operate series-strings of such cells with average voltage equal to their rated value, which helps maintain cell voltage uniformity. Restated, in contrast with type I and II electrochemical capacitors, type III capacitors should not be de-rated when series connected to form high-voltage series strings.

Cell Balancing in a Series String

Series connecting a number of electrochemical capacitor cells usually requires an active or passive voltage leveling system. For example attaching a parallel string of precision resistors to help pin the voltage of each cell. Typically, resistance values are selected so that the current flowing through the resistor string is approximately ten times the current flowing through the capacitor string. With this ratio, and during static operation, the resistor string establishes the individual cell voltages. A disadvantage of this passive approach is high self-discharge rate, since the string of resistors will discharge the capacitor. A related approach to provide cell balance but without the self-discharge problem is to use a parallel string of Zener diodes. Such devices appear as open circuit below a specified voltage, and a short circuit above that voltage. These methods add cost and complexity to the system.

There are also active approaches for balancing cell voltages where each cell is monitored. This information can be used to report over-voltage problems that may occur in series strings, or it may be used to actually control the voltage on each cell by charging or discharging individual cells in the string. Active balancing has been used with batteries and some electrochemical capacitors in the past. It is often used at the cell level, but sometimes this balancing is only needed between modules in a multi module system.

Note that the above balancing approach is normally effective at low power levels; that is, a few hundred milliamps during float conditions. If dynamic cell balancing is needed for a particular application a much higher rated leveling circuit will be required for the higher currents. This may add substantial cost to the system. Nevertheless, such an approach can be effective for raising the voltage of capacitors in a string to an average value that is closer to the maximum possible value, increasing energy density and perhaps offsetting the additional cost.

Temperature Variations in a Series String

Even with highly uniform cells there are still potential problems when cells are connected in series that have temperature non-uniformities. If a large module is warmer at the center due to cycling or warmer at the perimeter because of environmental factors, a temperature gradient will exist and could create cell voltage imbalance. This situation is true for all electrochemical capacitor designs. The solution to this problem is to engineer the system so that every cell within the system is held to within some specified temperature tolerance. Without this consideration, cells that are from a theoretically perfect manufacturing line (no variability) still may have cell voltage balance problems when operated within a series string.

Power Electronics Requirements

A unique characteristic of a capacitive energy storage system is that the state of charge of the system is always known–it is determined by the voltage. This is very different from most battery storage systems. It is usual to exploit this feature when charging and discharging a capacitor.

The sloping discharge of a capacitor, however, does present problems in applications that demand a constant voltage. In this case, power electronics are needed to boost the voltage of the discharging capacitor to a higher, constant value. Generally, a capacitor storage system will have very large capacitance, small inductance, and small resistance. Thus, it can act as its own filter during charge. The single limitation is that self-heating from its charging source must not create over-temperature conditions in the cells. Heat dissipation depends on the value of the ripple current, the value of the charging current, and the cell equivalent series resistance. Thus, low-cost charging sources can be employed, ones that are typically unsuited for battery charging.

A practical difference between the power source used for charging a capacitor and that used for charging a battery is the power level. Charging can be much faster for a capacitor than for a typical lead-acid battery design since they have minimal chemical reactions for charge storage. Capacitors generally can be charged at any rate provided overheating does not occur. This means that higher power chargers can be effectively used for capacitors since they can be charged in seconds to minutes, not hours. Similarly, their discharge rate can be high and is only limited by the series resistance of the capacitor. However, high-rate charge and discharge, particularly with cycling, can lead to internal heating of the capacitor, which without dissipation, can lead to over-temperature conditions and system failure as described previously. Shorting an electrochemical capacitor generally does not cause damage provided maximum temperatures are not exceeded. Type III and IV capacitors generally cannot be left in a shorted state without damage. Also they have a minimum operating voltage before damage may occur.

Health, Safety, and Environmental Issues

Safety issues can be grouped into several categories. One relates to electrical, a second to chemical, and a third to fire and explosion hazards. Electrical hazards are similar to those of batteries, not any better and not any worse. Hazards from chemical burns and chemical exposures can be similar to some batteries. Fire hazard is essentially nonexistent for type I and III products, which have aqueous electrolyte. For type II capacitors, fire hazard should be similar to some organic electrolyte batteries. An unknown safety related issue arises because acetonitrile is contained in the electrolyte of some large type II capacitors (see discussion under Chemical Hazards about acetonitrile). This situation has not been fully evaluated for potential problems it may create in larger scale utility or automotive applications.

To consider these issues, it is helpful to identify the exact materials used in each type of capacitor. Large type I capacitors use potassium hydroxide electrolyte, carbon electrodes, and generally nickel or steel current collectors or conductive polymer bipolar plates. Packages are generally steel or epoxy. The Elit and the ECOND companies make capacitors using this construction.

Type II electrochemical capacitors use carbon electrodes, paper or polymer separators, aluminum current collectors, and usually an acetonitrile solvent containing an ammonium salt for the electrolyte. Manufacturers of large type II capacitors include Maxwell, Panasonic, NESS, and EPCOS.

Type III electrochemical capacitors use nickel-oxyhydroxide positive electrodes, carbon negative electrodes, potassium hydroxide electrolyte, polyethylene case, polymer separator, and module packages generally of steel or a polymer. ESMA is the manufacturer of commercial products of this type.

Type IV devices are under development. They use carbon for one electrode and various types of battery electrodes for the second electrode. Electrolytes typically are various salt-containing organic solvents including acetonitrile-based solutions in some cases.

Electrical Hazards

Series-strings of the electrochemical capacitor cells often have voltages at lethal levels. These systems are similar to any voltage source with respect to electrical operating safety. Electrochemical capacitor systems are capable of delivering very high currents, higher than comparable lead-acid battery systems for instance, which can cause severe electrical burns from inadvertent short circuit. Safe operation procedures are exactly like those for battery systems of the same voltage and capacity.

Chemical Hazards

Aqueous electrolyte type electrochemical capacitors contain potassium hydroxide solutions at approximately 30-wt % concentration. This is similar to the electrolyte used in nickel metal hydride and nickel cadmium batteries, and in primary alkali cells. It is a common electrolyte, but it can cause chemical burns if contacted to bare skin as well as eye injuries. Safe operating procedures are similar to those for battery systems with the same electrolyte.

Some of the large type II capacitors contain acetonitrile solvent in their electrolyte. The synonym for the chemical acetonitrile is methyl cyanide. This chemical can create severe health problems from exposure due to respiration, ingestion, or skin contact. The amount of acetonitrile used in the electrolyte varies. The material specification data sheets (MSDS) will state percentages. Some type IV products under development also are reported to contain acetonitrile solvent.

Fire and Explosion Hazards

Whenever there is a concentrated quantity of stored energy, the possibility always exists of creating high temperatures that can lead to combustion. Type I and III products generally do not have fire hazard problems because they use an aqueous electrolyte. Type II products, with organic electrolytes may present a potential fire hazard problem. For example acetonitrile solvent is highly volatile and has flammability like kerosene and depending on the application may be classified as a fire hazard.

All commercial electrochemical capacitors should be designed so that they are safe and will not explode under any operating or use condition. Type I devices having aqueous electrolyte will become hot and vent steam under extreme conditions, but they should not explode. Type II products usually have a hermetic package. If they have a functioning safety pressure release valve, then they should vent before package rupturing. Type III products are expected to use water-based electrolytes and to be packaged in plastic containers with a resealable pressure release valve. Thus they present little hazard from explosion. Type IV products are presently in the research and development stage so it is not possible to comment on their safety. The issues of fire and explosion will be based on product designs and materials, which are not in their final form.

Disposal and/or Recycling

There are presently no recycling programs for electrochemical capacitors. There is no motivation to recycle some symmetric capacitors 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. Nickel current collectors are used in some type I products. There are well-established programs for recycling these nickel-containing batteries. It is possible that recycling of the battery-like electrode and nickel collectors could be accommodated into these programs, once such capacitor products come into general use. The carbon electrodes and aqueous electrolyte in these capacitors present no specified disposal issues.

Cell Life Prediction

The life of a particular type of capacitor cell can be determined by testing a number of cells at a variety of temperature and voltage conditions. Capacitor failure is usually defined as a certain percentage loss of capacitance, increase in series resistance, or increase in leakage current. Also complete failure can occur due to an open or short circuit. Note that charge/discharge cycling is not a first-order determinant of cell life unless the cycle rate causes cell overheating.

Background and Status

Brief 25-Year Product History

The concept of storing electrical energy in the electric double surface layer that is naturally formed at the interface between an electrolyte and a solid has been known since the late 1800's. General Electric reported the first two-terminal device based on this charge-storage mechanism in 1957. In 1962, Standard Oil of Ohio filed a patent application for a practical energy storage device based on charge storage in an electric double layer. The patent, awarded in November

1966, formed the basis for subsequent patents and eventual licensing. New ideas with configurations ruled to be outside these early patents have resulted in patents by numerous business entities around the world.

One of the earliest electrochemical capacitor products to be introduced was by Nippon Electric Corporation (NEC) under license from Standard Oil of Ohio (SOHIO) in August 1978. NEC created the name Supercapacitor and has used it as the name of their electrochemical capacitor product family. Production proceeded with the start of mass production in January, 1980, and sales to the Japanese market. In 1982, NEC introduced a new line of electrochemical capacitors having a different design optimization. This was repeated again in 1983, in 1987, and again in 1988. In general, each of these type I product lines was optimized for a different application. Large capacitors now under development by NEC are aimed at the automotive market.

One very interesting feature of the NEC product is the use of bipolar construction. NEC developed processes to assemble six or more cells in a series-stack and successfully seal the perimeter of the device. This is significant because it eliminated the need for external cell interconnects as is required with single-cell construction. This same approach has been used in large capacitors manufactured by ECOND and ELIT.

Panasonic started manufacturing their Goldcap electrochemical capacitor in 1978. The two major differences between the Panasonic and the NEC products were the electrolyte and the construction. The Panasonic Goldcap has a type II design. It uses an organic electrolyte with a spiral-wound single-cell construction.

Early Panasonic products were rated at <2 V_{dc}/cell. In the middle 1980's, their products were available in sizes up to several Farads. Panasonic began manufacturing much larger electrochemical capacitors in the 1990's, with early products having 470 or 1500 Farad ratings at 2.3 V_{dc}. These devices were extensively tested by the DOE for possible use in electric vehicle load leveling. Subsequent advances increased the capacitance of the 470 Farad-size products to 700 Farads, and ultimately to 2000 Farads and with a rating of 2.5 V_{dc}.

Maxwell Technologies began development efforts on electrochemical capacitors in the early 1990's after receiving a DOE contract to develop an advanced electric vehicle load-leveling capacitor. Development was initially confined to type I products, then switched to type II products in an effort to obtain higher energy density. Maxwell has developed 8-kJ cells using an accordion-fold design with carbon cloth electrodes and organic electrolyte. They presently are developing a spiral-wound design using particulate carbon.

At about the same time in Japan, the Okamura Laboratory begin working on a type II design that used active power electronics for controlling and leveling multi-cell modules. Several patents have been obtained in Japan and the U.S. Results of this work were first published in English at the electric vehicle conference, EVS-13 in 1996, and some time later at the International Seminar on Double Layer Capacitors held annually in south Florida. The design technique, under the trademark ECaSS, has led to relatively high reported specific energies in the 4-6 Wh/kg range. Several Japanese manufactures including Shizuki Electric, Nissan Diesel and Power Systems Ltd, offer either capacitor modules or products that use this design.

The first reported activity on type III capacitors was from Russia. The Elit Company made asymmetric capacitors based on nickel oxyhydroxide and carbon electrodes with potassium hydroxide electrolyte. These devices were used to power wheel chairs and subsequently, children's toy cars. This company later concentrated on, and has widely commercialized a type I carbon/carbon electrochemical capacitor.

The Russian company ECOND presented a paper in the U.S. in late 1993 that described type I electrochemical capacitors much larger in size than any device then available or under development in the U.S. Their capacitors were described as the power source for starting diesel internal combustion engines of sizes up to 3000 horsepower, including locomotive engines. The 1993 paper was certainly an eye-opener for some U.S. researchers involved in the development of 1.8 MJ electric vehicle load-leveling capacitors. As with ELIT, this work was a giant step ahead of research that had been reported in the U.S. and provided encouragement to many capacitor developers.

Type III development activities continued in Russia and were greatly expanded by the Joint Stock Company ESMA, a Moscow-based developer and manufacturer. This company reported using type III capacitors to power electric buses and electric trucks in 1997, with capacitors being the sole energy source in the vehicles. These 30 MJ capacitor storage systems far surpassed the size of any previously reported system. ELTON, the ESMA parent company, has patents that cover the asymmetric capacitor concept, i.e. type III and IV designs.

There is considerable development activity today on type IV capacitor products. These include use of lithium battery intercalation electrodes in combination with activated carbon double-layer charge storage electrodes. Development along this line has progressed rapidly due to the exploitation of material advances made on Li-ion battery technology.

Today's Manufacturers and Products

There are only a limited number of manufacturers now making large electrochemical capacitor products. A brief description of each company and their large capacitor products is given in Table 14-3.

Table 14-3
Manufacturers of Large Capacitor Products

Manufacturer	Country	State of the Technology	Typical Energy Storage and DC Voltage Ratings	Technology V_{dc}/Cell
ECOND	Russia	Commercial products	40 kJ, 14-200 V modules	type I, .9
Elit Stock Company	Russia	Commercial products	50 kJ, 14-400 V	type I, .9
EPCOS AG	Germany	Commercial products	15 kJ, 2.5 V 40 kJ, 14 V	type II, 2.5-2.7
ESMA Joint Stock Company	Russia	Commercial products	20 kJ – 1.2 MJ, 14 V 30 MJ, 180 V modules	type III, 1.4-1.6
Maxwell Technologies, Inc.	USA	Commercial products	8 kJ, 2.5 V	type II, 2.3-2.5
NESS Capacitor Company	Korea	Commercial products	18 kJ, 2.7 V	type II, 2.5-2.7
NEC Tokin	Japan	Development	8 kJ, 14 V	Type I, .9
Okamura Laboratory, Inc. with license of ECaSS to Shizuki, Nissan, etc.	Japan	Commercial products	1350-1500 F, 2.7V 35 F, 346V, 75 F, 54V	Type II, 2.5-2.7
Panasonic	Japan	Commercial products	6 kJ, 2.5 V	Type II, 2.5-2.7
Saft	France	Advanced prototype	10 kJ, 2.5 V	Type II, 2.5-2.7

ECOND

The ECOND capacitor made in Moscow, Russia, has bipolar construction with KOH electrolyte. It is a cylinder approximately nine inches in diameter, and, depending on energy, a height from several inches up to more that two feet. Capacitor energies range up to 45 kJ in size. Equivalent series resistances are typically in the milliohm range. Voltages up to 200 V_{dc} are common. Their RC time constant is below one second, considerably less than many competitive products. This capacitor technology has not changed significantly from when it was first described in the U.S. in 1993.

ECOND products have been used in many demonstration systems including diesel truck starting and in hybrid electric vehicles. ECOND capacitors were used in the first large-scale hybrid bus demonstration in North America that had capacitor energy storage. This 40-ft-long city transit bus was a gas/electric hybrid system that contained a 1.5 MJ, 400 V_{dc} capacitor system. ECOND capacitors are available from their North American distributor, Tavrima Canada, Inc.

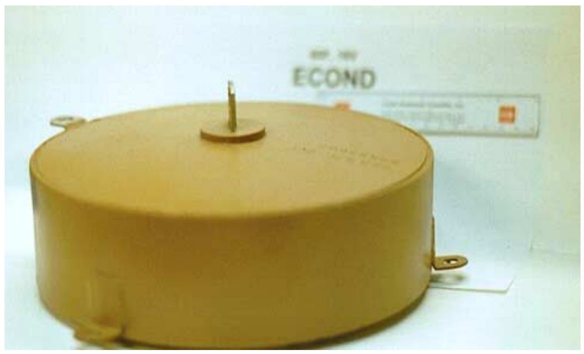

Figure 14-4
ECOND Capacitor 60F, 16V (Six-Inch Ruler Also Shown)

ELIT

The ELIT Company started operation in 1990 in Kursk, Russia. Their early devices were designed to power wheel chairs and subsequently for children's toy cars. ELIT has concentrated on carbon-carbon electrochemical capacitors, which led to the development of a broad line of type I products having significant sales volume in the U.S. Capacitors with voltages as high as 400 V_{dc} are now available.

A reader's letter to *Battery International* from Alexey Beliakov in early 1993 corrected information in an earlier issue by pointing out the existence of their large electrochemical capacitors. Pictures of 30 and 50 kJ, 12 and 24 V_{dc} capacitors were shown. He described the testing they had done on such capacitors and mentioned delivery of 600 kJ capacitor systems. Capacitors of such size and sophistication were totally unheard of at that time in the U.S. The complete line of ELIT capacitor products is available from their factory in Kursk, Russia.

Figure 14-5
Elit Capacitor 0.8 F, 310 V_{dc}, 19 kg (Six-Inch Ruler Also Shown)

EPCOS

EPCOS licensed electrochemical capacitor technology from Maxwell Technologies in the late 1990's and offered identical products to the European market for several years. They now have developed a new family of products, which range from 1000 F to 5000 F at 2.3 or 2.5 V_{dc}. EPCOS capacitors are type II products with accordion-fold carbon cloth or, for the new family, spiral-wound pasted carbon construction. Some contain acetonitrile in their electrolyte. Some have both terminals at one end of the package, but their newer products have a terminal at each end. EPCOS capacitors (of this new design only) are available in North America through their Munich, Germany office.

Figure 14-6
EPCOS Family of EC Capacitors and Modules From 5000F at 2.5V to 150F at 42 V

ESMA

ESMA products were first described in the U.S. during a conference presentation in 1997. Photographs of buses and trucks that were powered solely by electrochemical capacitors were shown. Many members of the audience missed the point that these vehicles actually had no batteries or an engine, only capacitor energy storage. These vehicles stored approximately 30 MJ of energy in capacitors, perhaps the largest-size capacitor system then in use. The capacitor storage technology used by ESMA was type III, which they referred to as an asymmetric capacitor. Since this first report, they have presented many technical papers that further describe and explain this mating of a battery-like Faradaic charge storage electrode with a capacitor-like double layer charge storage electrode.

Products sold by ESMA range from 20-kJ, 14 V_{dc} modules up to multi-MJ, 600 V_{dc} systems. Cell construction is similar to that of aircraft NiCd batteries, but with activated carbon substituted for the cadmium in the negative electrode. ESMA capacitors have a flooded cell design, which provides the ability to voltage-balance cells when connected in a series string.

ESMA has optimized their capacitors for either pulse or traction applications. The pulse capacitor is intended for discharges of a few seconds like needed for starting an internal combustion engine. The traction capacitor is designed to power electric vehicles like fork lifts, utility vehicles, trucks, buses, etc. These devices can be charged much quicker than a battery, in 12 to 15 minutes with a high-power supply, and then be discharged over a period of an hour or longer. ESMA capacitors and systems are available from their factory in Troitsk, Russia. Private-labeled capacitors for the starting of commercial trucks are available from their distributor, Kold-Ban International in Lake in the Hills, Illinois.

Figure 14-7
ESMA 10-Cell Module 1000F @ 14.5V_{dc} (Six-Inch Ruler Also Shown)

Maxwell

Maxwell Technologies had a broad line of high-voltage electrostatic capacitor products when they were awarded a contract by the U.S. Department of Energy for electrochemical capacitor development in 1991. The goal was to develop a powerful energy storage technology that would be suitable for electric vehicle load leveling. The desired capacitor would store 500 Wh (1.8 MJ) of energy, deliver 50 kW of power, be rated at 300 V_{dc} or higher, weigh less than 100 kg, and have material costs below $1000. Maxwell initially worked with Auburn University on this project. Their approach was a type I capacitor product that used a metal/carbon fiber composite electrode with potassium hydroxide electrolyte. Later efforts were directed to a type II design to increase device energy density. In the mid 1990s, Maxwell moved this project from Auburn to its manufacturing plant in San Diego, where it is located today.

Maxwell is the leading US producer of large electrochemical capacitors. They manufacture capacitor cells up to 2700 F. Their packaging is well engineered with welded metal construction, and in some products, glass-to-metal seals for electrical feed through. Their large devices have been used in numerous demonstration programs including in hybrid vehicles, power quality applications, and engine starting. Maxwell licensed their technology to the German company EPCOS in the late 1990s.

They recently acquired the Swiss company Montena that has extensive winding technology capabilities. In the middle of 2002, they announced, but have not introduced, a new product line having a pasted electrode in a spiral-wound design. This technology should allow substantially lower material and production costs. Major markets for the large Maxwell capacitors are in vehicle and telecommunication power applications.

Maxwell has undertaken a vigorous cost reduction program for their large capacitors. This effort involves replacing the carbon cloth electrode material with a particulate carbon, and using these electrodes in a spiral-wound assembly. Maxwell capacitor products are available from their main offices in San Diego, California.

Figure 14-8
Maxwell Capacitor 2700F, 2.5 V_{dc}

Montena

Montena is a Swiss company that produced spiral wound, type II electrochemical capacitors in addition to capacitor manufacturing equipment. Maxwell Technologies acquired Montena in 2002, and their product lines have been merged.

NEC Tokin

The Japanese company NEC was one of the first to commercialize double layer products. They still sell the small capacitors under the name "Supercap." NEC Tokin is now developing larger "Hypercap" capacitors, primarily for the automotive market. These are type I design, using sulfuric acid electrolyte, prismatic in form, and available either optimized for high energy or for high power. Special large capacitor products from NEC Tokin are available through their Japanese factory. Figure 14-9 shows two samples.

Figure 14-9
Samples of NEC Tokin Products

NESS

NESS electrochemical capacitor technology is a spin-off from the Korean DAEWOO Group in 1998. They have rapidly created a broad product line of electrochemical capacitors and developed automated capacitor manufacturing capability. NESS capacitors include type II products with a spiral wound cell construction. Their first commercial shipment of capacitors to the U.S. market was in mid-2000. NESS presently makes cells up to 5000 farads in size, some rated at 2.7 V_{dc}, among the highest voltage ratings available. Their larger capacitor cells have prismatic packages for efficient stacking in modules. NESS recently introduced a 42 V_{dc} capacitor module for the emerging automotive market. NESS capacitor products are available from their Korean home office.

Figure 14-10
NESS CAP 5000 F, 2.7 V_{dc} (Six-Inch Ruler Also Shown)

Okamura Laboratory, Inc. (ECaSS)

Capacitor systems based on an Okamura Lab design approach consist of large electrochemical capacitors with active electronic voltage control. These have been reported at professional meetings and were recently presented in the company web site. The distinguishing feature is that active voltage control is integral to the capacitor system and only operates to adjust the maximum charging voltage of individual cells, a technique called monitoring and initializing. The advantage is that the adjusting current for each capacitor cell will converge to the level of the leakage current, which is negligible in terms of energy consumption.

The Okamura Laboratory is located in Japan and does not sell capacitors directly. They partner with other capacitor manufactures, apply their design expertise to the cell design, and then add active controls to modules. The individual capacitor cells are typically prismatic geometry, of type II design, and do not contain acetonitrile in the electrolyte. Okamura has reported that a number of their systems are in use for demonstration projects associated with vehicular and UPS applications at several hundred volts. Figure 14-11 shows three of their manufacturing partner's products.

Figure 14-11
ECaSS Commercial Capacitors; From Left, Nissan Diesel (346V_{dc}, 35F, 6.3Wh/kg), Shizuki Electric “Faradcap” (FML-2A, 54V_{dc}, 75F, 30Wh), Power Systems (HO2A, 54V_{dc}, 65F, 6.5Wh/kg)

Panasonic

The Panasonic "Goldcap" capacitor, introduced in 1978, was initially developed for memory backup applications to replace the unreliable coin cell batteries in use at that time. It was not until the 1990s that Panasonic began manufacturing much larger electrochemical capacitor prototypes in Japan. In 1999, Panasonic introduced their UpCap capacitor for transportation applications, such as needed for hybrid vehicles. One version of the UpCap is rated at 2000 farads and 2.5 V_{dc}. It is a type II device that has been very well engineered. It uses a sophisticated double-seal arrangement in the crimped package, a lower cost approach than welded construction for preventing water entry into the package. It has essentially many tabs to the spiral-wound foils at each end of the package, which helps in reducing the series resistance. Furthermore, this arrangement helps to extract internally generated heat, which is important for applications like a hybrid vehicles where there are continuous repetitive charge/discharge cycles. The UpCap is currently available in high-power and high-energy versions, and under evaluation for many applications. See Figure 14-12.

These products are available from Panasonic Automotive Electronics Company in Southfield, Michigan.

Figure 14-12
Panasonic 2000 F, 2.3 V_{dc} (Six-Inch Ruler Also Shown)

Saft

Saft's electrochemical capacitor program compliments their large lithium ion battery products. Saft manufactures their large capacitors in France. The product is available in two variations: high energy and high power. The products are of type II design, have cylindrical geometry with a terminal on each end, and are available with capacitance values up to 3200 F. See Figure 14-13. The manufacturing is at the stage of advanced prototype. These capacitor products may be purchased from the Saft's Cockeysville, Maryland office.

Figure 14-13
Saft 3200 F, 2.5 V_{dc} (Six-Inch Ruler Also Shown)

Current Technology Developments

Current development thrusts generally relate to capacitor design, manufacturing cost reductions, and electrode materials development. Capacitor researchers apparently see performance or other advantages of the asymmetric design and are making it popular. Numerous research papers have been presented on this concept since it was first described in 1997. Patents are appearing with various descriptions of type III and IV materials and construction. For example, of the ~45 papers presented at the 2002 Spring meeting of the Electrochemical Society, 18 were related to asymmetric electrochemical capacitors. There were few if any presented on this topic at previous meetings. Electrochemical Society meetings represent a forum where professionals often first present major developments and new technology directions.

Another current development thrust relates to technical issues surrounding capacitor thermal management. Here interest originates from the need to create large, high-voltage energy storage systems capable of rapid cycling. Such systems require uniform voltage among the many capacitor cells in series-connected strings for reliable operation. This motivates increased emphasis on cell temperature uniformity and efficient heat removal from cells. Although charge/discharge efficiency is generally high for capacitors, they nevertheless dissipate energy, which can cause excessive internal temperature rise without appropriate heat removal techniques.

An important issue related to the creation of reliable high-voltage strings of cells is cell uniformity. So reducing manufacturing variability is certainly important. Improving control of the production process is an ongoing effort for many companies according to recent reports. Still another issue in capacitor design relates to product cost reduction. For example, Maxwell has reported on their cost-reduction program. They are developing spiral-wound cell construction capability using particulate-carbon electrode materials pasted on current collectors. This is in contrast with the carbon cloth used with a manual, accordion-fold design.

Development thrusts in electrode materials include examining the performance of various activated carbons to find lower-cost materials. Some new carbon materials are being implemented. Several companies are attempting to find replacements for activated carbon cloth material, which is much more expensive than the particulate carbon, especially particulate materials that have a natural origin. Other electrode materials that have been investigated include metal-oxides of ignoble elements, ones having good performance without associated high-costs typically found in the platinum group metals. There has been some development activity using nano-structured materials, both for carbons in symmetric double layer capacitors, and in the pseudocapacitor electrode of an asymmetric capacitor.

The third major development thrust has been with the electrolyte. Work has been reported on using polymer electrolytes for both aqueous and non-aqueous designs. Also, there has been some effort to find replacement materials for the acetonitrile-based electrolytes used in many type II products. The performance of these electrolytes is very good but its use creates concerns because of toxicity and safety issues.

The thrusts for the asymmetric capacitor activity have expanded from the nickel oxyhydroxide/carbon system to other systems including a lead oxide/carbon system and a MnO_2/carbon system. Reports of device performance using these other material systems are most encouraging. A major advantage of these systems is low materials cost. Yet another system that has been described in several papers recently is a lithium-titanate electrode in combination with a carbon electrode and an organic electrolyte. This design offers higher voltage than can be obtained in present symmetric organic electrolyte capacitors, and it is referred to as a type IV electrochemical capacitor.

Yet another design that has been described in the literature is a graphite/carbon capacitor. This type IV capacitor relies on charge intercalation in the graphite of one electrode and double layer charge storage on activated carbon in the other electrode. The electrolyte for this system is an organic solvent with a lithium salt. This particular system has an operating voltage approaching 4 V_{dc}. None of these advanced devices are commercially available at this time.

Technology in the Next Ten Years

It is interesting to speculate about the future performance of electrochemical capacitors. In the next three to five years, type II capacitors cells are predicted to achieve stable operation at 3.0 V_{dc}. This represents a significant increase in energy density over the present products, perhaps 50% higher than is available today. With this higher operating voltage will come increased stability, possibly increased operating temperature, and perhaps with suitable emphasis in organic electrolyte development, creation of a non-toxic type II electrolyte capable of high power performance.

Type III capacitors in the next several years should approach an energy density of 70 kJ/kg, which represents a 100% increase in energy density over products available today. There could also be significant cost reductions as a result of the introduction of lower cost designs that are described in the patent literature.

Longer term, type II capacitors will probably remain fixed at 3.0 V_{dc} operation because further increases in electrolyte and electrode purity will become cost prohibitive. Furthermore, emphasis by small-capacitor developers on increasing cell operating voltage will wane since the portable electronic applications will decrease to below 3.0 V_{dc}. But improved stability at the 3 V_{dc} level is anticipated, particularly at elevated temperatures. Type IV electrochemical capacitors should become commercially available, for example the graphite/carbon system and the lithium-titanate system. Energy densities of 100 kJ/kg may become available, which is solidly placed in the range of today's lead acid batteries.

Which type will become the dominant capacitive energy storage technology in the future? This is impossible to predict with any certainty. However, for applications where cost is a major issue, the dominant technology will probably have an aqueous electrolyte. This lowers the cost of materials as well as manufacturing processes. For instance, aqueous electrolyte products generally do not require special conditioned space like dry rooms, or special drying systems to remove water impurities from cells before sealing like what is needed with the non-aqueous electrolytes. Yet another related cost issue is capacitor packaging. Aqueous electrolyte products generally are sealed in a low-cost crimped metal or plastic package to reduce loss of water—the design need not be highly sophisticated. In contrast, organic electrolyte products must be hermetically sealed in a low-permeability container like metal and often incorporate a sophisticated glass-to-metal seal for electrical feed-through. These materials and package designs add considerable costs to a product.

Of the aqueous electrolyte capacitors on the horizon today, type III electrochemical capacitors offer significant performance advantages including higher energy density and voltage balance. So, this particular design is predicted to become the dominant capacitor technology of the future for applications where cost is a driver. Since many utility and transportation applications are cost sensitive, type III capacitors are predicted to dominate these markets.

It is possible to estimate future cost difference between the organic and the aqueous electrolyte products by examining the present cost differences between lithium-ion and nickel-metal hydride batteries. The organic electrolyte battery presently costs about twice as much as the aqueous battery. Both of these technologies are in large-volume production. So cost differences for the capacitor types when in large-volume production may mimic this behavior, i.e., organic electrolyte capacitors will continue to cost more than aqueous electrolyte capacitors, perhaps two-times higher.

Integrated Electrochemical Capacitor Systems for the Utility Industry

In recent years, improvements in manufacturing quality, reductions in cost, and superior leveling circuitry have greatly simplified the construction of long series strings of electrochemical capacitors. These developments have resulted in the emergence of high-voltage, high-power electrochemical capacitor systems for a number of applications. While most such applications are still in the proof-of-concept or prototype product stages, they are built with commercial electrochemical capacitor products.

Most applications of high-voltage electrochemical capacitor systems today are focused on transportation applications, such as short-duration energy storage for hybrid-electric automobiles. Nonetheless, there are several demonstrations of interest to the utility industry, and in particular to transmission and distribution applications. These include bridge power systems, the Siemens SITRAS SES system, and the TVA TUCAP demonstration project.

Electrochemical Capacitor Bridge Power Systems

The objective of the bridging power system is to carry the critical load away from an out-of-spec or failing power source, and to a stable alternate source. The system is effectively a battery-less standby UPS. Several key functions are required to accomplish this objective. These are rapid isolation from the failing source, recovery using local storage, energy conversion, synchronization, paralleling and soft transfer switching between the primary and alternative power source. Optional functions that may add value to this application are: additional power conditioning and filtering, full-time reactive and real power stabilization, harmonic cancellation, the control and dispatch of distributed generation, interconnection protection and load control.

Figure 14-14 shows each of the basic functions in a generic circuit configuration.

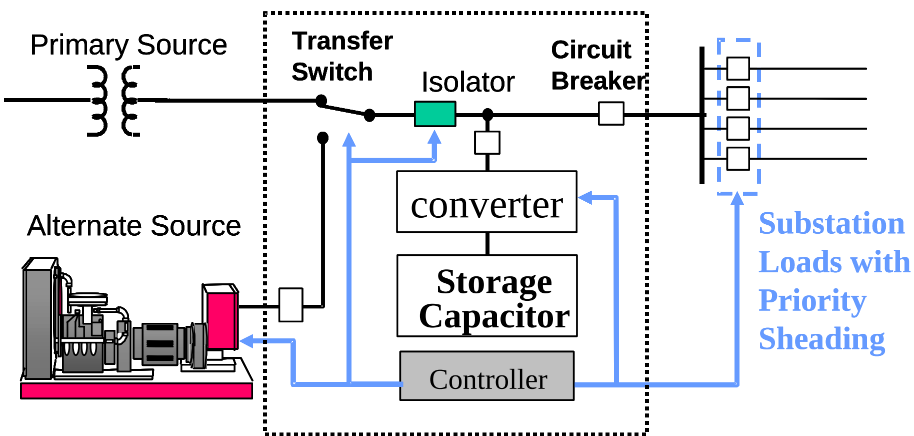

Figure 14-14
Generic Circuit Configuration for a Substation Bridging Power System

Typically, the bridging application transfers the facility load from the primary power source to a stand-by engine generator set. In addition, the application includes the transfer back to the primary source after power is restored, and these transitions must be seamless without causing any disruption to the source, load or facility. Characteristics of available bridging power systems are:

- Interruption protection within cycles
- Bridging power to alternate source - typically 10–20 seconds

- Synchronized control for paralleling and seamless transfer
- Single and 3-phase systems range from kWs to MWs at low to medium ac voltage
- Interconnection protection and load control may also be provided

Figure 14-15 shows an electrochemical capacitor bridging power system designed for a 100-kW DC load. This system is constructed from nine ESMA 30EC402 modules connected in series. Each module contains thirty 9900 F electrochemical capacitors in series, and operates between 42 and 21 V_{dc}. The system uses a DC-to-DC converter to deliver $600V_{dc}$. This system will carry the load for up to 10 seconds during an outage, and will boost the DC voltage during voltage sags.

Figure 14-15
Electrochemical Capacitor System for DC Ridethrough

By applying electrochemical capacitors in a bridging power system there are several potential benefits in addition to outage protection, for example:

- Momentary missing-voltage replacement where the electrochemical capacitor system supplements the reduced voltage during a fault or a severe overload condition, without the need to start back-up generation, covers 80-90% of events. Normally the duration of this support is less than 15 cycles or 250 milliseconds.
- Providing required bridging power where the electrochemical capacitors carry and serve the local load, with both real and reactive power, during transfer between alternate power sources. Bridging power is for a few seconds during transfer to a hot standby power source or up to 15 seconds for transfer to a cold-start generator.

- Supplementing a small standby power source as a source of current for starting or for handling other momentary overloads when operating standalone. This allows reduced size and inrush capacity in the alternate source.

Siemens Sitras SES System

A common problem with electric mass transit arises from the large load that appears when trains leave a station. This situation often leads to voltage variations in the local distribution network. These variations can affect performance of other load equipment connected nearby.

This problem can be easily solved if the energy that the train loses when slowing down is used to accelerate the train when it leaves. The kinetic energy of the moving train is converted into electrical energy by the same motors that accelerate the train. This energy is ordinarily dissipated in large resistors located on the train itself. An appropriate energy storage system would allow this energy to be stored and used again during acceleration.

The Siemens Sitras SES (Static Energy Storage) system is designed to capture energy during breaking of a light rail vehicle, and store it until it is necessary for accelerating a vehicle. This reduces the effect of the acceleration and braking on the local electrical distribution system in addition to reducing energy consumption in the rail network, without affecting the efficiency of the rail system [1].

The Sitras SES system is constructed from thirty-two racks of electrochemical capacitors, each rack containing forty-two Maxwell Technologies 2400F cells in series, for a total of 1,344 cells. The energy storage operates between 750 V_{dc} and 375 V_{dc}. The system has a total energy storage capacity of 2.3 kWh, and a maximum power rating of 1 MW_{dc} [2]. See Figure 14-16.

Figure 14-16
Siemens Sitras SES System (Courtesy Siemens Transportation Systems)

Test systems of the Sitras SES systems have been placed in Portland and Dresden. One of the field trialsdemonstrated that the power drawn from the main power supply was reduced by 50 kW_{ac} on average. This reduction in power allowed the power requirement of the local substation to be reduced by about 30% for a significant cost saving [1].

Stored Energy for "Distributed Mini FACTS" Controllers

This application is based on the benefits of active power injection coupled with dynamic reactive power exchange for improved stability in the power system. The need for dynamic reactive power compensation ("fast VARs") as opposed to fixed or mechanically switched capacitor banks have long been recognized as a way to improve T&D system stability and increase power transfer limits. This concept has been applied in large-scale inverter-based Flexible AC Transmission Systems (FACTS). These systems have the ability to affect changes of 10 to 100 MVAR and respond in less than one-quarter of a cycle and they have brought about a new way of thinking regarding active and reactive power.

The use of large-scale (100 MVAR or more) FACTS controllers to provide dynamic reactive compensation has already been demonstrated through several landmark projects. However, because of high initial cost, the alternative of a smaller scale, modularized, distributed real and reactive VAR injection system, called a "mini-FACTS" controller, has recently received considerable attention. Combining electrochemical capacitor energy storage with appropriate bi-directional electronic power conversion provides a legitimate distributed mini-FACTS controller.

Figure 14-17 shows a conceptual block diagram of the electrochemical capacitor-based mini-FACTS controller system. This system may be controlled to act as a stabilizer for distribution feeders, acting on post-disturbance voltage to assist in returning the voltage and frequency to an equilibrium status within one second.

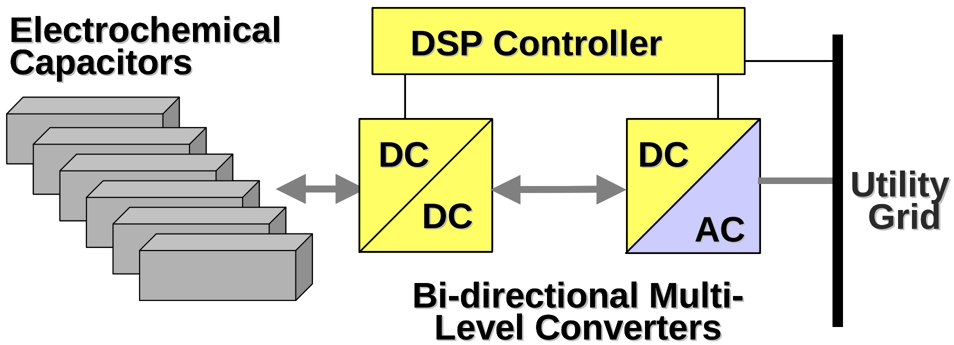

Figure 14-17
Concept of Electrochemical Capacitor-Based Mini-FACTS Controllers Coupled to Utility Grid

In 2002, TVA funded a project with EPRI PEAC to identify the technical obstacles to the development of kilovolt-level electrochemical capacitor strings for mini-FACTS devices, along with possible solutions to these obstacles. The goal of the project was the construction of a 2000 V_{dc} string of electrochemical capacitors. This string would eventually be tested with a medium-voltage FACTS device under development by TVA.

The proof-of-concept system, shown in Figure 14-18, developed by EPRI PEAC connected forty-five ESMA 30EC502 capacitor modules in series. Each module contains thirty 6000 F electrochemical capacitors connected in series, and operates between 45 and 27 V_{dc}. The string is rated to deliver about 1.5 MW_{dc} for about 1 second. The energy storage incorporates cell leveling circuitry at the module level, with additional circuitry to allow leveling at the module level.

Figure 14-18
Demonstration 2 kV, 1 MW_{dc} Electrochemical Capacitor String for Mini-FACTS Controller

TVA's vision for the distributed mini-FACTS controller is the development of a transportable system including several strings of electrochemical capacitors with a high-voltage power electronics package capable of providing dynamic reactive power compensation at the location where it would have the greatest impact.

T&D System Energy Storage System Applications

Select Applications for Electrochemical Capacitor Systems

This section presents the select applications for which electrochemical capacitors are suited and describes the key features of such systems when configured to meet the select application requirements. Screening economic analyses have shown that electrochemical capacitor systems are potentially competitive for some of the single function applications, but not any of the combined function applications, which are described in detail in Chapter 3. The following list briefly summarizes all of the Chapter 3 applications, with a reiteration of the key application requirements. Those for which electrochemical capacitor systems are best suited are enclosed by borders.

Single Function Applications

Application A: Grid Angular Stability (GAS) – mitigation of power oscillations by injection and absorption of real power at periods of 1 to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 20 oscillatory cycles, cumulatively equivalent to a full power discharge (FPD) of 1 second duration; 1 event per day; 10 events per year. Valued at the cost of alternative solutions.

Application B: Grid Voltage Stability (GVS) – mitigation of degraded voltage by additional reactive power plus injection of real power for durations up to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 1 second FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application C: Grid Frequency Excursion Suppression (GFS) – "prompt" spinning reserve (or load) for mitigating load-generation imbalance. Requires energy storage to discharge real power for durations up to 30 minutes. The reference duty cycle for analysis is standby for infrequent events characterized by 15-minute FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application D: Regulation Control (RC) – system frequency regulation in concert with load following. The reference duty cycle for analysis is characterized by continuous cycles equivalent to 7.5-minute FPD and charge cycle (triangular waveform), 2 cycles per hour deployed with 10 minutes advance notice. Valued at market rates.

Application E: Spinning Reserve (SR) – reserve power for at least 2 hours with 10 minute notice. The reference duty cycle for analysis is standby for infrequent events characterized by 2-hour FPD, 1 event per day, 10 events per year. Valued at market rates.

Application F: Short Duration Power Quality (SPQ) – capability to mitigate voltage sags (e.g., recloser events). The reference duty cycle for analysis is standby for infrequent events characterized by 5 seconds FPD, 1 event per hour, 5 events per day, 100 events per year. Valued at the cost of alternative solutions.

Application G: Long Duration Power Quality (LPQ) – SPQ, plus capability to provide several hours reserve power. The reference duty cycle for analysis is standby for infrequent events characterized by SPQ plus standby for 4 hours FPD, 1 event per year. Valued at the cost of alternative solutions.

Application H: 3-hr Load Shifting (LS3) – shifting 3 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 3-hour FPD, 1 event per day, 60 events per year. Valued at market rates.

Application I: 10-hr Load Shifting (LS10) – shifting 10 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 10-hour FPD, 1 event per day, 250 events per year. Valued at market rates.

Combined Function Applications (In the Order Noted)

Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC)

Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR)

Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR)

Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR)

Application C5: Combined Applications I, D, E (LS10 + RC + SR)

Electrochemical Capacitor Energy Storage System Compliance With Application Requirements

The electrochemical capacitor performance parameters discussed above were used to develop approximate sizes and operational parameters for systems meeting the application requirements for the selected applications described in the previous section. Key factors in sizing electrochemical capacitor systems include:

- Selection of the type of electrochemical capacitor and pulse factor (which determines the minimum discharge voltage and therefore the PCS cost as described in Section 5). For applications requiring less than 15 seconds (e.g., SPQ), systems may use a "discontinuous" (pulsed discharge) IGBT-based PCS that accommodates high currents for brief periods, provided voltage levels are within the parameters of such a PCS.
- The pulse performance of the electrochemical capacitor. As described above, the energy delivered by a capacitor decreases non-linearly with increasing power, and quickly falls off for durations below 1 second.
- Monitoring and balancing circuits to provide cell voltage balance. These circuits are generally required for all electrochemical capacitor systems.
- Thermal management to ensure that cell temperatures are maintained within the acceptable range.

Performance aspects of electrochemical capacitor systems for the selected applications are described below and summarized in Table 14-4. The reference power for all applications is 10 MW_{ac}. In each of these applications, several possible products can be used to build the system. In the examples below, the systems are designed with a specific product by way of example, and should not be understood to advocate a particular product for this application.

- Application A: Angular Instability (GAS) – Application A: Grid Angular Stability (GAS) – This application requires that the system continuously detect and mitigate power oscillations, up to 10 times a year. Oscillations require that the system inject power for the equivalent of 1 second at the full power rating. 15 ESMA 30EC104 electrochemical capacitor modules are linked in series to produce a string with a nominal voltage of 630 V_{dc}. 35 such strings are linked in parallel, and connected with a Type III PCS with a pulse factor of 5. The net efficiency of the system is 98%, and the expected lifetime is 20 years.
- Application B: Grid Voltage Stability (GVS) – This application requires that the system continuously detect and mitigate power oscillations. Oscillations require that the system alternately inject and absorb full power, for an equivalent of a 1 sec full power discharge. 15 ESMA 30EC104 electrochemical capacitor modules are linked in series to produce a string with a nominal voltage of 630 V_{dc}. 35 such strings are linked in parallel, and connected with a Type III PCS with a pulse factor of 5. The net efficiency of the system is 98%, and the expected lifetime is 20 years.
- Application F: Short Duration Power Quality (SPQ) – This application requires that the system continuously detect and mitigate infrequent PQ events lasting up to 2 seconds. 15 ESMA 30EC104 electrochemical capacitor modules are linked in series to produce a string with a nominal voltage of 630 V_{dc}. 44 such strings are linked in parallel, and connected with

a Type III PCS with a pulse factor of 5. The net efficiency of the system is 98%, and the expected lifetime is 20 years. Note that a larger number of strings is required for this application in comparison to Applications A and B, since the discharge length is twice as long.

Table 14-4
Electrochemical Capacitor System Compliance With Application Requirements

	Single Function		
Applications	**App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d**	**App B: GVS -- 1 sec FPD per cycle, 10 events/yr, 1 event/d**	**App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr**
Energy Storage Selection			
Type of Product	ESMA 30EC104 12 Module Rack	ESMA 30EC104 12 Module Rack	ESMA 30EC104 12 Module Rack
Number of Strings	35	35	44
Pulse Factor	5.0	5.0	5.0
Max Charge Voltage	675	675	675
Min Discharge Voltage	338	338	338
Maximum DOD, %	100%	100%	100%
Cumulative Cycle Fraction	0%	0%	2%
Replacement Interval, yr	20	20	20
PCS Selection			
PCS Type (Chapter 5)	III	III	III
Duty Cycles			
Grid Support or Power Quality (GS or PQ)			
Power, MW	10	10	10
Event Duration, Hr	0.000	0.000	0.001
Load Shifting (LS)			
Power, MW			
Load Shift Energy, MWh/yr			
Load Shift Losses, MWh/yr			
Cycle Life Fraction			
Regulation Control (RC)			
Power, MW			
Hours per day, hr			
Days per year, days			
RC, MW-Hours/yr			
RC Losses, MWh/yr			
Cycle Life Fraction			
Spinning Reserve (SR)			
Power, MW			
SR, MW-Hours			
SR Losses, MWh/yr			
Cycle Life Fraction			
Summary System Data			
Standby Hours per Year	8,760	8,760	8,760
System Net Efficiency, %	98.0%	98.0%	98.0%
Energy Storage Standby Efficiency, %	100.0%	100.0%	100.0%
PCS Standby Efficiency, %	98.0%	98.0%	98.0%
System Footprint, MW/sqft (MW/m^2)	0.007 (0.0752)	0.007 (0.0752)	0.0068 (0.0733)
Energy Storage Footprint, MW/sqft (MW/m^2)	0.0664 (0.7143)	0.0664 (0.7143)	0.0528 (0.5682)

Note: System net efficiency includes losses for energy conversion and system standby expressed on an annual basis, i.e., one minus inefficiency, where inefficiency equals the ratio of annual energy losses to the product of system rated power times 8760 hours, expressed in percent.

Benefit and Cost Analyses

Electrochemical Capacitor Pricing and Integrated System Costs

Electrochemical capacitor developers have traditionally focused on developing individual cells rather than larger systems. Since the late 1990s, a number of electrochemical capacitor manufacturers have begun producing integrated modules with monitoring and cell leveling circuitry built into the system. Such modules are much better suited for building systems at reasonable voltages.

The burgeoning interest in electrochemical capacitors in the automotive and military markets, as well as in utility markets, has caused many companies to invest significantly in commercialization of their technology. Several companies now offer standard module products, for which they predict prices will fall rapidly. Current nominal prices for utility scale applications are in the range of $1000 to $5000 per module, depending on the type of module, number of modules, and location of the project. For the Handbook's specified deployment date of 2006 and rating of 10MW, nominal unit prices are based on 2003 costs, with savings associated with design and initial volume manufacturing savings expected between 2003 and 2006. For replacement modules over the assumed 20 year project lifetimes, prices are based on large volume estimates from manufacturers. The resultant module prices applied for the benefit-cost assessments are:

EC Module	Energy (kJ)	Operating Voltage (V_{dc})	2006 Prices, K$	Mature Prices, K$
Tavrima (ECOND) ESCap 85/270	85	270	$1.5	$1.0
ELIT 290PP-45/0.25	45	290	$1.5	$0.7
ESMA 30EC104	94	42	$1.5	$1.1
Maxwell BMODO0115	128	42	$4.0	$2.7
Power Systems PMLF54-65	95	54	$4.0	$2.7

In addition to the electrochemical capacitor modules, the related scope of supply includes the cell monitoring and leveling system, as well as module packaging. Costs associated with shipment, import and export duties and fees, racking, intermodule connections, and module level monitoring must be added to the cost of the module themselves. Here they have been added to the cost of the energy storage portion of the cost.

The cost of integrated electrochemical capacitor systems is obtained by combining the cost of the above scope of supply with the appropriate PCS and BOP costs as described in Chapter 5. The PCS includes the power converter plus the grid disconnect and breaker protection, transformers, controller(s) to synchronize one or more electrochemical capacitor strings with the grid, and all equipment necessary for serving the load and isolating the system. The BOP scope of supply consists of grid connection at the point of common coupling, land and improvements (e.g., access, services, etc.) and is based on a nominal cost of $100/kW$_{ac}$. The PCS and BOP costs shown in Table 14-5 are based on the methodology described in Chapter 5. The cost of interior space equipped with HVAC systems is included at $100/sqft in accordance with general past experience.

Table 14-5
Capital and Operating Costs for Electrochemical Capacitor Systems

Applications	Single Function		
	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	App B: GVS -- 1 sec FPD per cycle, 10 events/yr, 1 event/d	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr
Energy Storage Capacity, MWh$_{ac}$	0.003	0.003	0.006
PCS Initial Cost, $/kW	153	153	153
BOP Initial Cost, $/kW	100	100	100
Energy Storage Initial Cost $/kW	162	162	203
Energy Storage Initial Cost $/kWh	580,000	580,000	370,000
Total Capital Cost, M$	4.1	4.1	4.6
O&M Cost – Fixed, $/kW-year	11.9	11.9	13.1
O&M Cost– Variable, $/kW-year	6.7	6.7	6.8
NPV Disposal Cost, $/kW	0.2	0.2	1.5

Note: The total initial cost may calculated in two ways:

1. By mutiplying the sum of PCS, BOP and Battery initial costs expressed in $/kW by the reference power,

2. OR by mutiplying the sum of PCS and BOP expressed in $/kW by the reference power and then adding the product of Battery Initial cost expressed in $/kWh and the Battery Capacity

Fixed O&M costs are based on $2/kW for the PCS as required by provisions in Chapter 5, plus maintenance on the electrochemical capacitor in accordance with the vendor. The recommended maintenance program varies greatly between different types of electrochemical capacitors, but generally consists of an annual visual inspection, which includes:

- Visual inspection for damage, leakage, or other physical problems with cells, interconnections, and connecting cables
- Cleaning the tops and sides of cells to remove dirt and deposited electrolyte salts

- Retorquing terminal connections as necessary
- Confirming the accuracy of DC voltage, DC current, and temperature sensors as necessary

Based on past experience gained with demonstration projects using ESMA capacitor modules, the levelized annual labor for a 12-module capacitor string is estimated at 9 hours. Fixed O&M costs are based on labor costs of $50 per hour (or $450 per module per year). In addition, an allowance for annual property taxes and insurance, based on 2% of the initial total capital costs, is included in the fixed O&M costs.

Variable O&M costs for the system include the cost of electrical losses to maintain the PCS during hot standby intervals and to maintain the voltage on the electrochemical capacitor. An allowance for disposal costs is included at the end of the system life, covering the cost of removing the electrochemical capacitor modules from the plant. ESMA modules do not contain hazardous materials and are recyclable at any location that processes nickel-based batteries. Other types of electrochemical capacitors may require special processing.

Lifecycle Benefit and Cost Analysis for Electrochemical Capacitor Systems

Further insight to the value of energy storage can be gained through lifecycle cost analyses using a net present value (NPV) methodology and comparison with alternatives. The financial parameters in Table 14-6 are used to assess the applications described in the preceding sections and the assumed electricity rate structure is presented in Table 14-7.

Table 14-6
Financial Parameters

Dollar Value	2003
System Startup	June 2006
Project Life, years	20
Discount Rate (before tax), %	7.5
Property Taxes & Insurance, %/year	2
Fixed Charge Rate, %/year	9.81

Table 14-7
Electric Rates

Load Shifting On Peak Period	3	10
Number Cycles per year	60	250
On-Peak Energy, $/MWh	120	80
Off-Peak Energy, $/MWh	20	
Yearly Average Energy Charge, $/MWh	38	
Regulation Control, $MW-Hour (power), $/MWh	16	
Spinning Reserve, $MW-Hour (power), $/MWh	3	
Transmission Demand Charge, $/kW-mo	5	

The results of lifecycle cost benefit analyses of select applications are summarized in Table 14-8 and discussed below. The bases and methodology used in valuing energy storage applications is described in detail in Chapter 4. The details of the cost benefit analysis for each application are discussed below.

Table 14-8
Summary of Benefit and Cost Analyses of Electrochemical Capacitor Systems

Applications	Single Function		
	App A: GAS -- 1 sec FPD equivalent over 20 oscillations per event, 10 events/yr, 1 event/d	App B: GVS -- 1 sec FPD per cycle, 10 events/yr, 1 event/d	App F: SPQ -- 2 sec FPD per cycle, 100 events/yr, 5 events/d, 1 event/hr
Alt Solution Value, $/kW	750	500	1,000
Initial Installed Cost, M$	4.15	4.15	4.56
Total Costs, M$	(6.0)	(6.0)	(6.6)
Total Benefits, M$	7.50	5.00	10.0
Benefit to Cost Ratio	1.24	0.83	1.51
NPV, M$	1.5	(1.0)	3.4
Battery Module	ESMA 30EC104 12 Module Rack	ESMA 30EC104 12 Module Rack	ESMA 30EC104 12 Module Rack
Number of Modules	35	35	44
Energy Storage 2006 Price, K$/module	1,530	1,530	1,530
Energy Storage Price for NPV=0, K$/module	3,650	(75)	5,395

- Application A: Grid Angular Stability (GAS) – This application was evaluated on the assumption that an alternative system capable of mitigating GAS events can be obtained for capitalized acquisition and operating costs of $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 14-8, this application yields a NPV of $1.5 million on an initial investment of about $4.2 million. As a measure of sensitivity of NPV with respect to alternative system costs, Figure 14-19 illustrates the change in NPV over a range of $500 to $1000/kW and shows that this electrochemical capacitor system competes favorably against alternative solutions with net capitalized costs in excess of about $605/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the ESMA 30EC104 module were increased from $1,530 to $3,650 per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $750/kW.

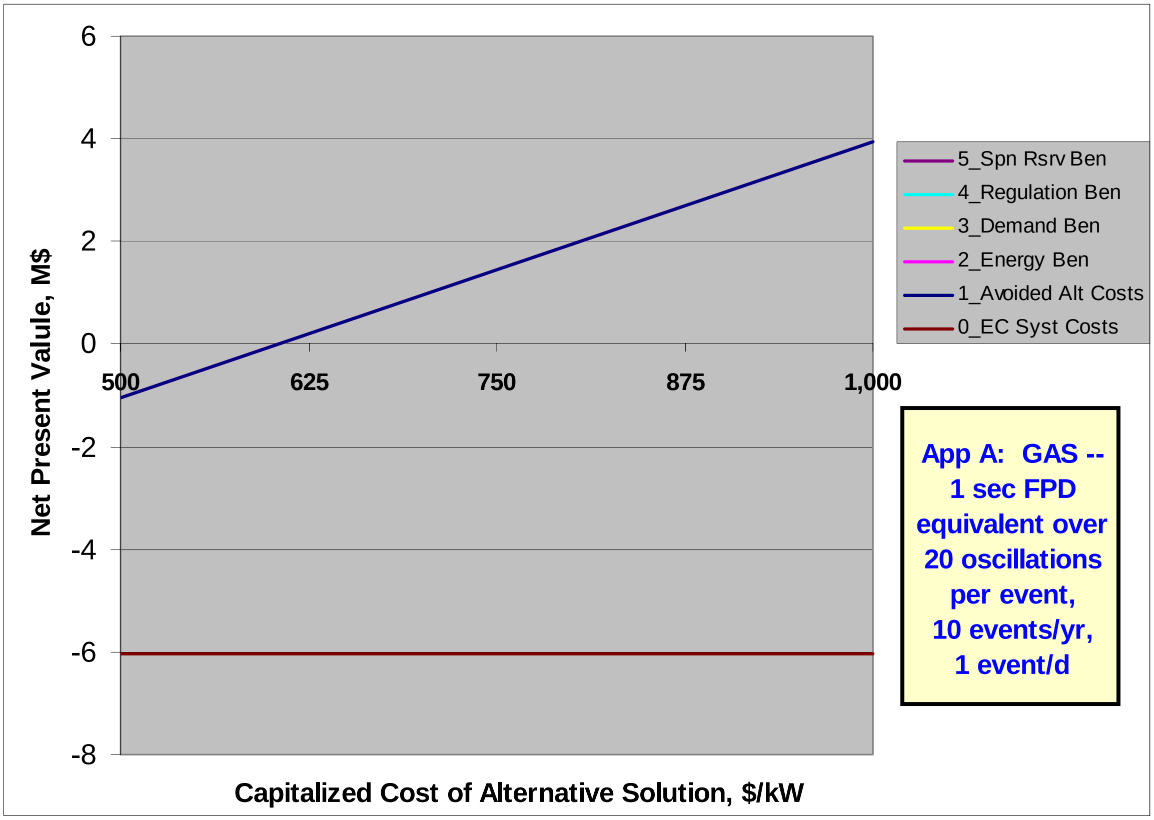

Figure 14-19
Application A: Electrochemical Capacitor System NPV vs Cost of Alternative System

- Application B: Grid Voltage Stability (GVS) – This application was evaluated on the assumption that an alternative system capable of mitigating GVS events can be obtained for capitalized acquisition and operating costs of $500/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 14-8, this application yields a negative NPV of $(1.0) million on an initial investment of about $4.2M. As a measure of sensitivity of NPV with respect to alternative system costs, Figure 14-20 illustrates the change in NPV over a range of $250 to $750/kW and shows that this electrochemical capacitor system competes favorably against alternative solutions with net capitalized costs in excess of about $605/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, the price of the ESMA 30EC104 module would need to be reduced from $1,530 to a negative value, $(75) per module, for the NPV to equal zero, i.e., for costs and benefits to equal those for alternative solutions valued at $500/kW.

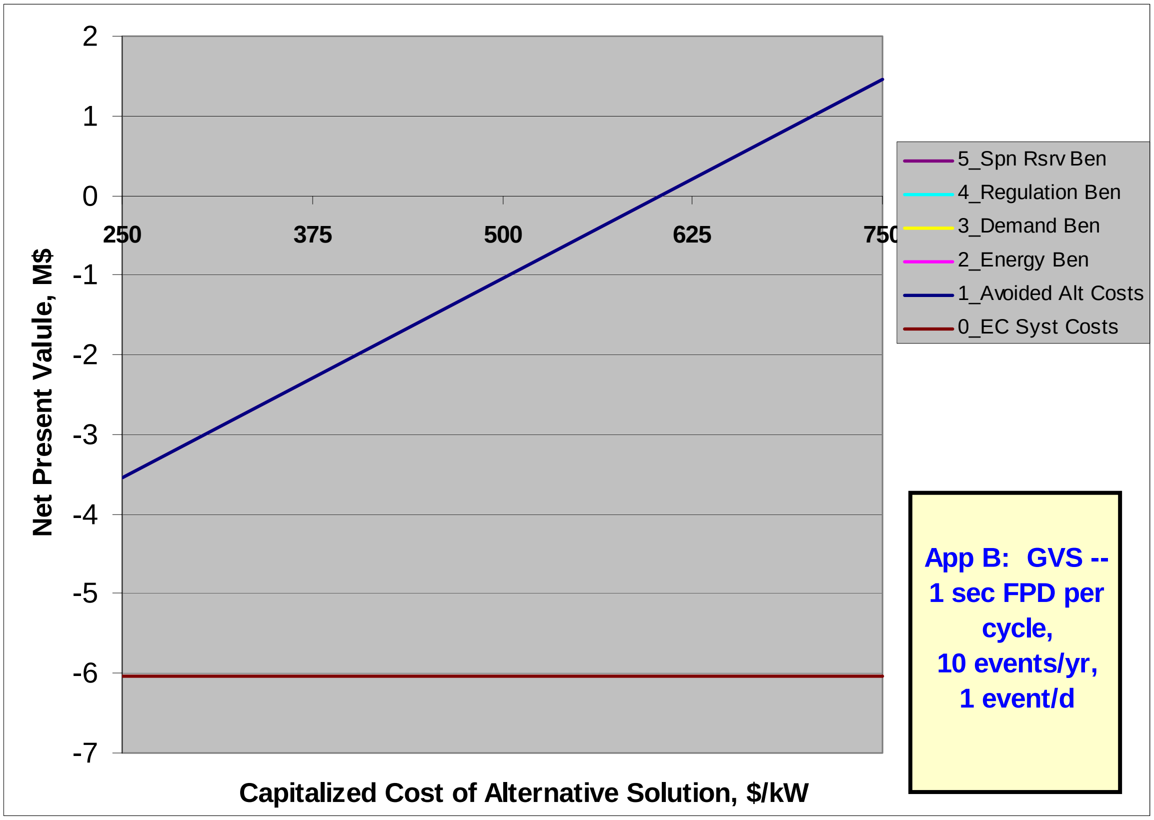

Figure 14-20
Application B: Electrochemical Capacitor System NPV vs Cost of Alternative System

- Application F: Short Duration Power Quality (SPQ) – This application was evaluated on the assumption that an alternative system capable of mitigating SPQ events can be obtained for capitalized acquisition and operating costs of about $1000/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. As shown in Table 14-8, this application yields a NPV of about $3.4 million for an initial investment of about $4.6 million on this basis. As a measure of the sensitivity of NPV with respect to alternative system costs, Figure 14-21 illustrates the change in NPV over a range of $500 to $1500/kW and shows that electrochemical capacitor systems will compete favorably against alternative solutions with net capitalized costs in excess of about $660/kW. As an additional indicator of NPV sensitivity with respect to the cost of energy storage, if the price of the ESMA 30EC104 module were increased from $1,530 to $5,395 per module, the NPV would equal zero, i.e., costs and benefits would be equal with those for alternative solutions valued at $1000/kW.

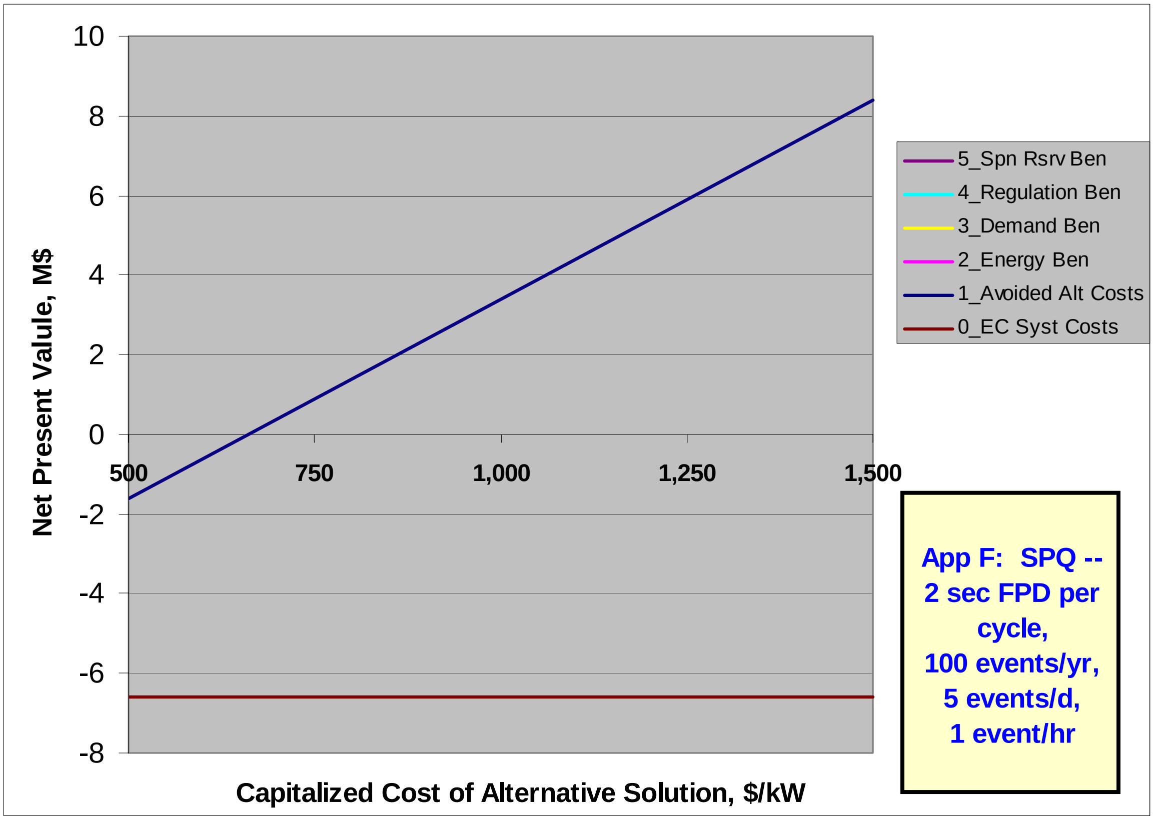

Figure 14-21
Application F: Electrochemical Capacitor System NPV vs Cost of Alternative System

Interpreting Results From Benefit-Cost Analyses

In general, electrochemical capacitor systems are expected to be attractive investments for very short duration single function applications.

The reader is reminded that the foregoing analyses are intended as a guide to the initial consideration of energy storage options, and that these analyses are based on representative electric rates and costs for alternative systems as described in Chapter 4. The assumptions used herein should be reviewed in light of project specific applications, alternative solutions, electric rates and financial parameters.

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15
COMPRESSED AIR ENERGY STORAGE

Introduction

Compressed air energy storage (CAES) offers a method to store low-cost off-peak energy in the form of stored compressed air (in an underground reservoir or an aboveground piping or vessel system) and to generate on-peak electricity by:

- Releasing the compressed air from the storage reservoir
- Preheating the cool, high-pressure air
- Directing the preheated air into an expansion turbine driving an electric generator

Figure 15-1 shows a large CAES plant design concept. Since the compressor and expander operate independently and at different times, CAES offers significant advantages over a conventional simple-cycle combustion turbine system, where approximately 55-70% of the expander power is used to drive the compressor.

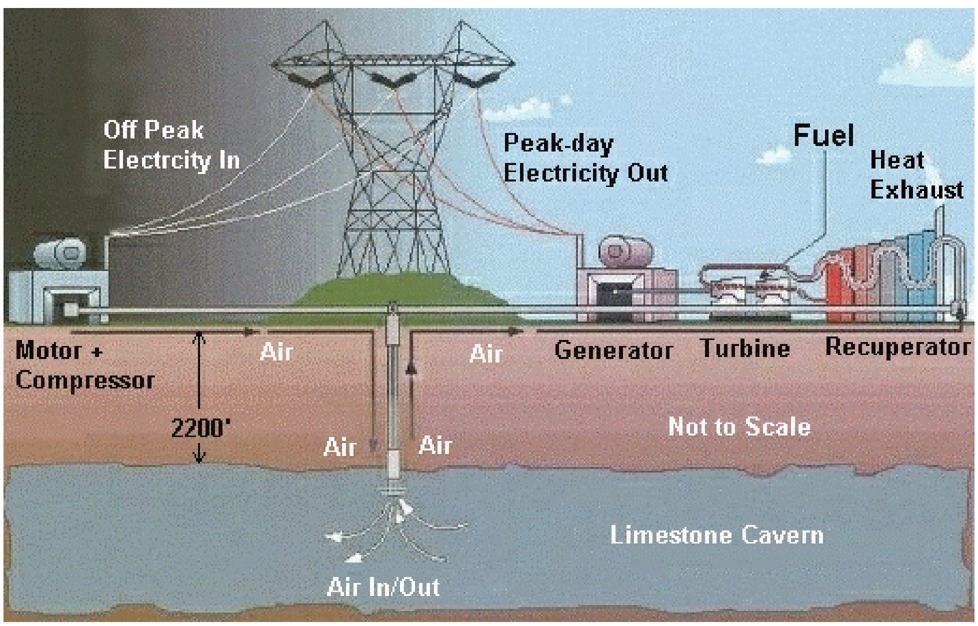

Figure 15-1
Typical Compressed Air Energy Storage Plant (The Plant Shown is the One Planned by Norton Energy Storage LLC)

The technological concept of compressed air energy storage is more than 40 years old. CAES was seriously investigated in the 1970s as a means to provide load following and to meet peak demand while maintaining constant capacity factor in the nuclear power industry. CAES technology has been commercially available since the late 1970s. One commercial CAES plant has been operating successfully since 1978, and another has been operating successfully since 1991. In addition, many other CAES plants have been investigated via siting, economic feasibility, or design studies.

The first and longest operating CAES facility in the world is near Huntorf, Germany. The 290 MW_{ac} Huntorf plant functions primarily for cyclic duty, ramping duty, and as a hot spinning reserve for the industrial customers in northwest Germany. Recently, this plant has been successfully leveling the variable power from numerous wind turbine generators in Germany.

The only CAES facility in the U.S., a 110 MW_{ac} plant near McIntosh, Alabama, performs a wide range of operating functions; namely,

- Load management
- Ramping duty
- Generation of peak power
- Synchronous condenser duty
- Spinning reserve duty

Many other CAES plants have been designed and/or investigated but were not built for a variety of reasons. Examples of such plants follow:

- During the Soviet era, a 1,050 MW_{ac} CAES plant using salt cavern geology formations for the air storage was proposed for construction in the Donbas area of Russia/Ukraine. Underground geological development of the air store using salt domes was initiated, but when the Soviet Union collapsed, the construction was terminated.
- Israel studied several CAES facilities, including a 3 x 100 MW_{ac} CAES plant facility using fractured rock aquifers [1].
- Luxembourg designed a 100 MW_{ac} CAES plant sharing an upper reservoir for a water compensation system with a pumped hydro plant located in a hard rock cavern at the Viendan site [2].
- Soyland Electric Cooperative, headquartered in Decatur, IL contracted for the construction of a 220 MW_{ac} hard rock based plant. Plant engineering and the cavern sample drilling/rock analysis were completed and all major equipment had been purchased when the project was terminated due to non-technical considerations arising from a change in the Board of Directors at the utility. ABB had been selected to manufacture the turbomachinery [2], and Gibbs & Hill, Inc. had been selected as the plant engineering company.

Description

CAES Technology

In CAES systems, electricity is used to compress air during off-peak hours when low-cost generating capacity is available. For power plants with energy storage in excess of approximately 100 MWh or 5 hours of storage, the compressed air is most economically stored underground in salt caverns, hard rock caverns, or porous rock formations. A CAES plant with underground storage must be built near a favorable geological formation. Aboveground compressed air storage in gas pipes or pressure vessels is practical and cost effective for storage plants with less than about 5 hours, however some above ground systems with up to about 10 hours of storage may be economically attractive depending on plant design and site conditions.

For a conventional CAES plant cycle (as illustrated in Figure 15-2), the major components include:

- A motor/generator with clutches on both ends (to engage/disengage it to/from the compressor train, the expander train, or both)
- Multi-stage air compressors with intercoolers to reduce the power requirements needed during the compression cycle, and with an aftercooler to reduce the storage volume requirements
- An expander train consisting of high- and low-pressure turboexpanders with combustors between stages
- Control system (to regulate and control the off-peak energy storage and peak power supply, to switch from the compressed air storage mode to the electric power generation mode, or to operate the plant as a synchronous condenser to regulate VARS on the grid)
- Auxiliary equipment (fuel storage and handling, cooling system, mechanical systems, electrical systems, heat exchangers)
- Underground or aboveground compressed air storage, including piping and fittings

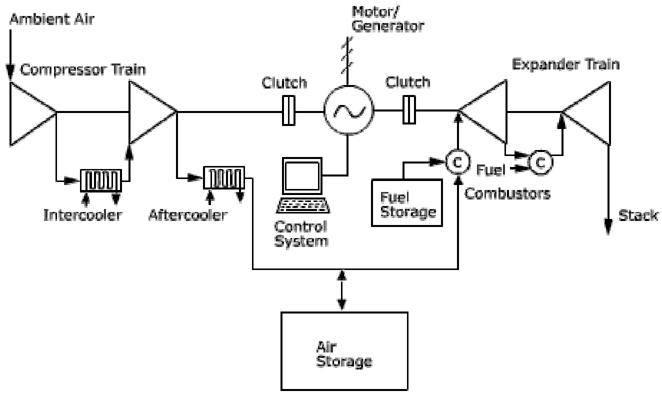

Figure 15-2
Conventional CAES Cycle

In the compressed air storage mode, the low cost off-peak electricity from the grid is used to operate the motor-driven compressor train to compress the air and to send it into a storage facility. In single-shaft CAES plant configurations, the shaft power to start the compressor may be supplied partially or completely by the expander. In the power generation mode, the compressed air is withdrawn from the storage reservoir, preheated in the recuperator, sometimes heated further via fuel burning in a combustor, and then expanded through the reheat turboexpander train to drive the generator to provide peak power to the grid. It should be noted that the compression and generation power ratings for the overall plant can be specified by the owner to be different values, to meet the power available during off-peak time periods versus the power needed during on-peak time periods.

While combustion turbines use standardized power plant equipment, CAES plants are optimized for specific site conditions such as the availability and price of off-peak energy, cost of fuel, storage type (and the local geology if underground storage is used), load management requirements, peaking power requirements and capital cost of the facility. By converting off-peak energy from the grid to compressed air and storing it for electric power generation during peak periods, utilities can defer or avoid higher capital-intensive generation, transmission, and distribution upgrades, yet they can still meet the peak electricity demand from their load centers.

The combustor can be designed to operate on a variety of fuels, including natural gas, oil, and hydrogen. Since CAES plants use a fuel to heat air during the discharge generation cycle, a CAES plant is not truly a "pure" energy storage plant such as pumped hydro, battery, and flywheel storage systems. In general, since fuel is used during a CAES plant's generation cycle, a CAES plant provides approximately 25-60% more energy to the grid during on-peak times than it uses for compression during off-peak times (the exact value of this percentage is determined by the specific CAES plant design selected by the plant owner). In addition, as was mentioned above, the power output of an expansion turbine used in a CAES plant provides 2 to 3 time more power to the grid than the same expansion turbine would provide to the grid if it were a part of a simple-cycle combustion turbine plant. This explains the exceptionally low specific fuel consumption (heat rate) of a CAES plant as compared to a combustion turbine. For example, if the expansion turbine element from a 100 MW_{ac} simple cycle combustion turbine were used in a CAES plant configuration, it would provide 250 to 300 MW_{ac} to the grid.

Compressed Air Energy Cycles

A variety of different thermodynamic cycles may be applied to the CAES plant design. The selection of any of the following cycles is driven by specific site conditions and operating requirements and has a significant impact on the plant costs, selection of plant components, and overall plant operating/performance characteristics:

- Conventional Cycle [3] – The conventional cycle illustrated in Figure 15-2 consists of the intercooled compressor train, reheat expander train, motor/generator, control system, and the air storage along with auxiliary equipment (fuel storage and handling, heat exchangers, mechanical systems, and electrical systems). The stored air is expanded through a reheat turboexpander train where the air is heated (via combustion of fuel) sequentially in the high-pressure and low-pressure combustors before entering the corresponding high-pressure and low-pressure expansion turbines. Such a configuration is used by the German Huntorf plant and is characterized by relatively high heat rate (approximately 5,500 Btu/kWh) compared to more recent CAES plant designs, as described below. This type of plant is best suited for peaking and spinning reserve duty applications.
- Recuperated Cycle [3] – This is the conventional CAES thermal cycle with an additional component (the recuperator), as illustrated in Figure 15-3. 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 is used in the Alabama McIntosh plant that was designed for primary operation as a source of peak power and as a load-management storage plant. Since the recuperator reduces the plant heat rate during generation by about 25%, it reduces the cost of the plants' peak power supply.

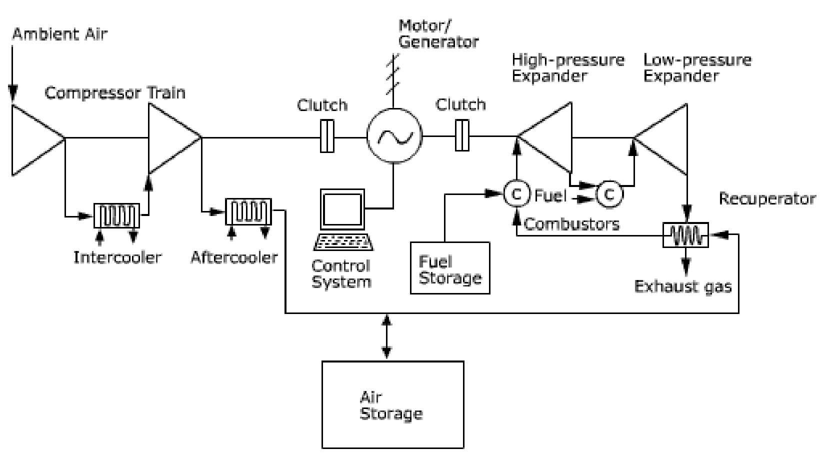

Figure 15-3
Recuperated Cycle

- Combined Cycle [4] –This is the conventional cycle with addition of a Heat Recovery Steam Generator (HRSG) and steam turbine, as shown in Figure 15-4. The exhaust heat from the low-pressure expander is recovered in the HRSG to produce steam, which in turn drives a steam turbine and provides additional power from the plant. Due to the thermodynamic inertia of the bottoming cycle equipment, the additional power generated by the bottoming steam cycle will reach full capacity in approximately one hour after the CAES plant start-up. Therefore, this concept is applicable for cases that need additional peak power for continuous long-term operations. Compared to the conventional cycle, this cycle reduces specific storage volume per kWh produced with a corresponding reduction in the storage reservoir costs.

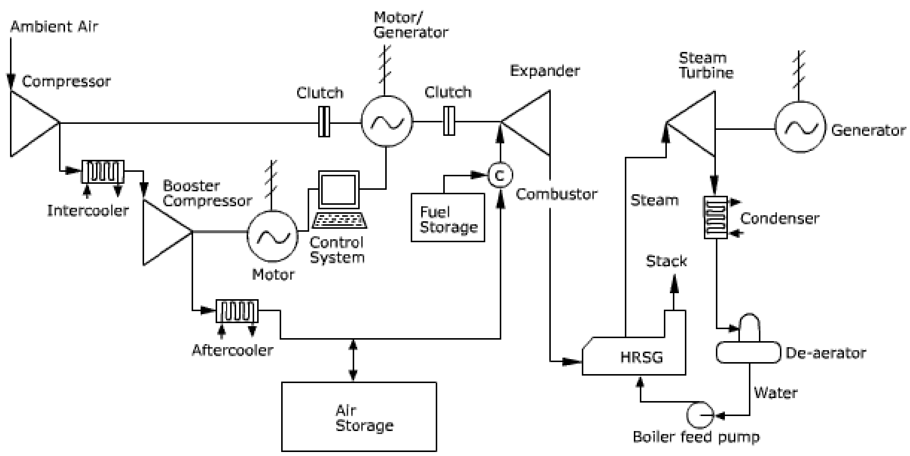

Figure 15-4
Combined Cycle With HRSG and Steam Turbine

- Steam-injected Cycle [3] – This is the conventional cycle adapted to use the HRSG to recover waste heat for steam production, as illustrated in Figure 15-5. The steam is added to the airflow from the storage reservoir to increase the mass flow through the expansion turbine during the generation cycle, thereby increasing the output power level from the plant. The mass of air needed to be stored per unit of power output is significantly reduced due to steam injection with corresponding reduction of the storage volume and costs. Similar to combined cycle gas turbine plants with steam injection, the additional power associated with steam injection in this CAES cycle follows the power level produced by the air expansion turbine. Like any steam-injected system, this concept uses demineralized water; thus, the cost of this type of water has to be included in economic feasibility studies for this type of plant.

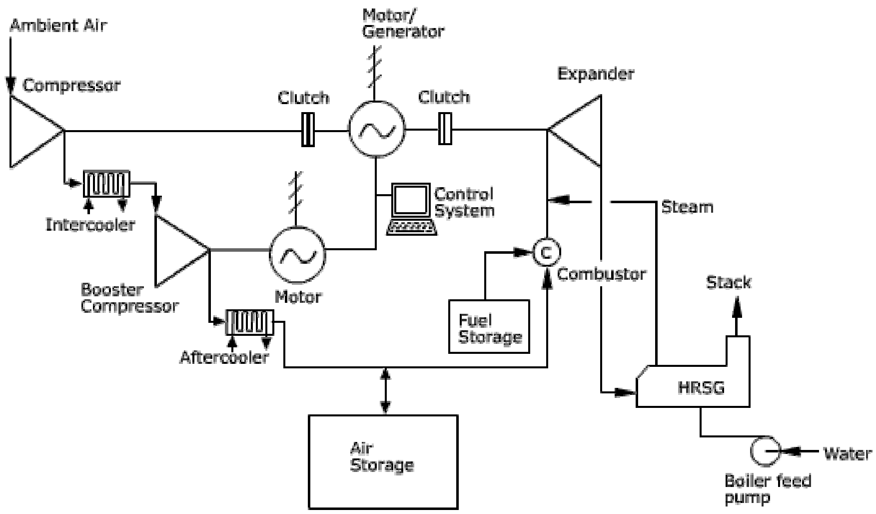

Figure 15-5
Steam-Injected Cycle

- Compressed Air Storage with Humidification (CASH) [3, 4] – As shown in Figure 15-6, the stored air is humidified in an air saturator before being injected into the combustion turbine. The mass of air needed to be stored per unit of power output is significantly reduced due to humidification. Thus, the size of the air storage reservoir required is much smaller than other types of CAES cycles. The dynamics of this concept are better than those for the combined cycle and steam injection concepts. This concept also uses water, although this water does not require demineralization.
- "Adiabatic" CAES Cycle – In this CAES cycle, the thermal energy recovered during the compression cycle is stored and used later to reheat the stored air during the generation cycle to reduce or even eliminate any fuel consumption. As illustrated in Figure 15-7, this type of cycle uses sensible or latent heat storage and recovery materials (e.g., basalt stone/thermal oils and phase change salts, respectively). Many such plants have been analyzed [5, 6]. Taken to the limit, the result is the so-called "adiabatic" CAES plant where no fuel is used during the plant's generation cycle. The round trip efficiency for this type of plant has been estimated to be 65%.

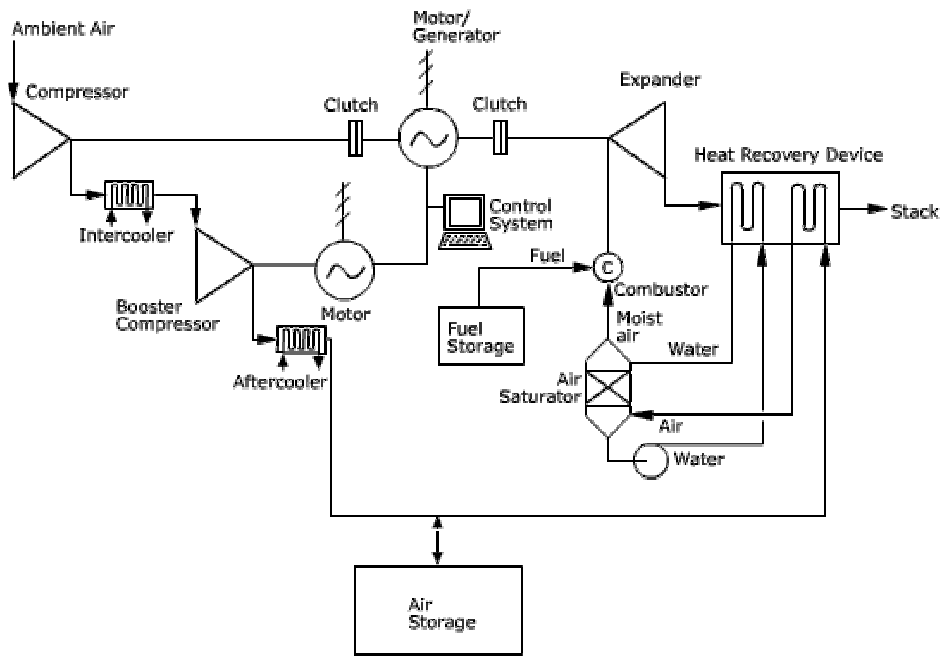

Figure 15-6
Compressed Air Storage With Humidification (CASH)

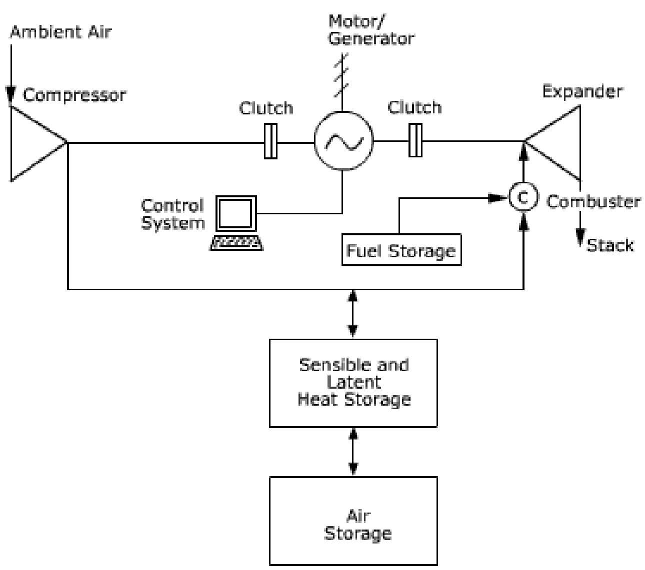

Figure 15-7
"Adiabatic" CAES Cycle

Compressed Air Storage Underground Facilities

The compressed air for the CAES plant may be stored underground, near the surface, or aboveground. Underground storage media may be in any of the following man-made and naturally occurring geological formations:

- Salt caverns created by solution mining (which typically costs about $1/kWh of energy produced) or dry mining (which typically costs about $10/kWh produced [7, 8]).
- Underground rock caverns created by excavating comparatively hard and impervious rock formations (either through new excavation for the CAES plant or in existing hard-rock mines) (which typically costs $30/kWh produced [9]).
- Naturally occurring porous rock formations (e.g., sandstone, fissured limestone) from porous rock aquifers or depleted gas or oilfields (which typically costs only $0.10/kWh produced [10]). It should be noted the porous rock aquifers used for CAES contain non-potable salt water.
- Abandoned limestone or coalmines (which typically cost about $10/kWh produced [11]).

In general, a geological formation suitable for underground air storage must meet the following requirements:

- The formation must have sufficient depth to allow safe operation at the required air pressure.
- For porous rock formations, the storage zone must be sufficiently porous to provide the required storage volume at the desired pressure and sufficiently permeable to permit the desired airflow rates. In addition, the over-burden and adjacent geological formations must have sufficient structural integrity to contain the air vertically and laterally; that is, the storage zone must be overlain by an impermeable rock layer to prevent the air from leaving the storage zone and escaping to the surface. All of these types of characteristics are the same as those used for over 80 years in the porous rock aquifer-based natural-gas storage industry.
- Porous rock formations need to possess a mineralogy that does not result in rapid chemical consumption of the oxygen in the stored air through oxidation reactions. This concern can be evaluated via laboratory tests of core samples from a site under consideration.

Geologic opportunities for CAES plants in the U.S. are shown in Figure 15-8, which indicates that over 80% of the U.S. territory has geological formations suitable for the underground air storage.

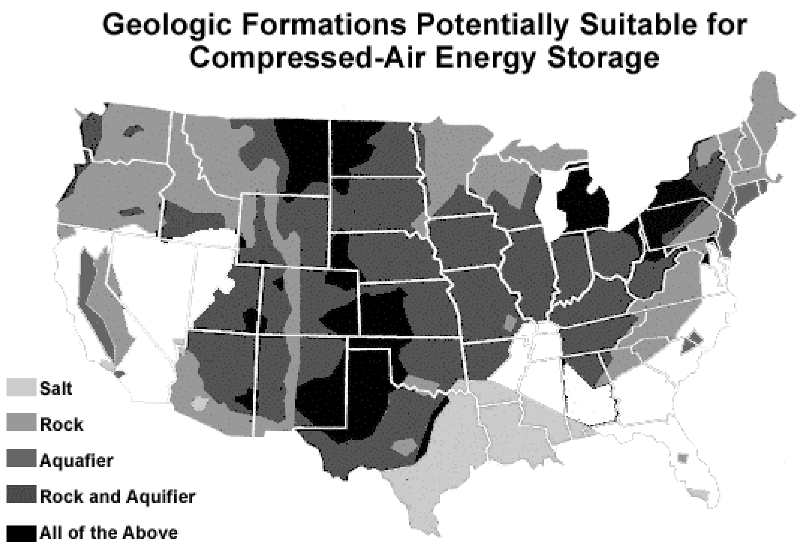

Figure 15-8
Geologic Opportunities for CAES Plant Sites in the U.S.

Deep underground caverns may be operated with or without hydraulic compensation. With hydraulic compensation, water at the bottom of the storage cavern is connected to a surface reservoir. Thus, the storage pressure is always at or near the hydrostatic pressure of the water column to the surface.

For caverns operated without hydraulic compensation (e.g., salt caverns), the air pressure varies between the two design pressure levels associated with the CAES plant. In addition, it is generally better to operate the surface turbomachinery at a constant pressure that is slightly lower than the lowest pressure in the cavern.

The Hybrid Plant Concept

As conceived by Dr. Michael Nakhamkin in 1998 under EPRI sponsorship, a hybrid CAES plant can be operated in a variety of modes [12]. The concept allows the plant to operate continuously as a base-load combustion turbine and, when necessary, to operate at increased power during peak hours to supply intermediate/maximum peak power as needed. This plant concept is particularly well suited for distributed power generation applications. At present, the only hybrid plant configuration developed is based on the Rolls Royce Allison Company's KM7 combustion turbine [13]. As such, the following is a brief description of the major operating modes of the hybrid concept sized using the KM7 turbine:

- Base load operation – The plant is operated as a conventional combustion turbine with 100% of the expander flow provided by the compressor. The turbine supplies a net power output of 4.8 MW_{ac} at 11,700 Btu/kWh.
- Intermediate peak load operation - The expander flow and power are increased because the expander receives compressed air flow from the storage reservoir in addition to the full airflow from the main compressor. It is estimated that when 20% additional airflow comes

from the storage reservoir, the net output power will be 7.9 MW_{ac} for 3 hours at 8,300 Btu/kWh.

- Maximum peak load operation -- The compressor is disengaged, and the full flow of the compressed air from the storage reservoir goes into the expander. The power output is approximately 16 MW_{ac} at a heat rate of approximately 4,000 Btu/kWh.
- Storage-charging mode of operation -- The off-peak power feeds both the motor-driven main compressor and the separate motor-driven boost compressor. For the KM7, 12.2 MW_{ac} of off-peak power is required to drive the compressors.
- Self-charging operation -- 78% of the main compressor's flow is sent to the expander to generate electric power to drive the booster compressor to fill the storage reservoir. This requires about 3.5 hours of charging time, with no power going to or from the grid.
- Synchronous condenser mode of operation – By opening the clutch between the compressor and the motor/generator, and between the expander and the motor/generator, the motor/generator is synchronized to the grid and is operated as a synchronous condenser, providing VARS for power factor correction. In this mode, the motor/generator works to stabilize line voltage and frequency, ease grid power transitions, and provides reactive power to assist in providing high quality electrical power to the grid.

Key Features and Limitations

The key features of compressed air energy storage offer several advantages over alternative energy storage technologies.

- The CAES plant is the only technology that can provide significant energy storage (in the thousands of MWhs) at relatively low costs (approximately \$400/kW_{ac} to \$500/kW_{ac}). The plant has practically unlimited flexibility for providing significant load management at the utility or regional levels.
- Commercial turboexpander units range in size from 10 -20 MW_{ac} (Rolls Royce-Allison) to 135 MW_{ac} (Dresser-Rand) to 300-400 MW_{ac} (Alstom).
- The CAES technology can be easily optimized for specific site conditions and economics.
- CAES is a proven technology and can be delivered on a competitive basis by a number of suppliers.
- CAES plants are capable of black start. Both the Huntorf and McIntosh plants have black-start capability that is occasionally required.
- CAES plants have fast startup time. If a CAES plant is operated as a hot spinning reserve, it can reach the maximum capacity within a few minutes. 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.
- As mentioned above, the nominal heat rate of a CAES plant at maximum load is about 2 to 3 times lower than the heat rate of a comparable combustion turbine plant using the same

turbine expander. CAES plants also excel at part load. Their heat rate at 20% of maximum load is 80% of the nominal heat rate at maximum load. This is very good and unique, since all other oil, gas, and coal power plants have poor efficiency at 20% of maximum load, making them uneconomical for operation at part load for normal duty. This characteristic of CAES plants make them very useful (and efficient) for ramping, part load, and regulation duty.

- A CAES plant can (and does) operate as a synchronous condenser when both clutches are opened (disconnecting the motor-generator from both the compressor train and the expander train), and the motor-generator is synchronized to the grid. VARS can be injected and withdrawn from the grid by modulating the exciter voltages. Both the Huntorf and the McIntosh plant are used in this manner. Since this operation does not require the use of stored air, the plant operator can choose to operate the plant in this mode for as long as necessary.

Given all these advantages, one could ask why there are so few CAES plants in operation, as of December, 2003. The main reason is probably the lack of awareness of this option by utility planners. In addition, for those that are aware of this option, the underground geology is likely perceived as a risk issue by utilities, even though oil and gas companies have been storing hydrocarbon-based fuels in similar underground reservoirs for over 80 years. Finally, very few utility engineers are aware of the fact that about 80% of the U.S. has suitable CAES sites.

The various storage options offer specific advantages and disadvantages. Underground storage can be designed to allow 10-30 hours of operation at full power in the range of 100-400 MW_{ac}. Site selection is somewhat limited since one needs the presence of mines, caverns, and certain geological formations. In contrast, aboveground storage, in general, allows for fewer hours of operation at the 10-20 MW_{ac} scale, but the site selection is much more flexible.

The project lead times for CAES plants are typically not more than three years, including development, design, construction, and startup. For example, the contract for the 110 MW_{ac} McIntosh plant was signed on June 1, 1988, and the plant was commissioned on June 1, 1991. For smaller plants, the construction time is about one year. Table 15-1 shows some of the common parameter ranges for CAES plants.

Table 15-2Table 15-2 shows typical ranges for air compression and electricity generation in CAES plants.

Table 15-1
Key CAES Features

Feature	Parameter Range
Space requirements	100-MW_{ac} plant needs about 1 acre
Effective Efficiency	85% (using the battery or pumped hydro analogy)
Life	30 years
Maintenance requirements	Same as simple cycle combustion turbine:
Environmental impact	Minimal (NOx is below 5 ppm)
Auxiliary equipment needs	Water if wet cooling is used; no water if dry cooling fans are used
Power conditioning needs	None

Table 15-2
Typical Charging and Discharging Characteristics (Based on 110 MW_{ac} McIntosh Plant)

Characteristic	"Charging" (Compression Mode)	"Discharging" (Generation Mode)
Electrical energy input	0.75 kWh input for every 1 kWh of output	N/A
Heat consumption with fuel	N/A	4,100 Btu/kWh of the net plant output
Storage capacity	1,950 MWh	2,600 MWh
Response time, standby to full power	4 minutes	Nominal: 10-12 minutes Emergency: 5-7 minutes
Response time (to switch from full power in compression mode to full power in generation mode)	Approx. 20 minutes (if solid-state drive is used, about 3 minutes)	N/A

Status

As of December 2003, there are only two operational CAES plants in the world. And, as of December, 2003, two additional CAES plants are under development in the U.S., and there may be two to four other CAES plants under development but information about them is unavailable due to confidentiality concerns by their developers.

Current and On-Going Development Efforts

CAES plants differ from other energy storage technologies in that they cannot be "mass-produced". Each project is individually developed, designed, and funded. As noted, there are two existing CAES plants in the world (Huntorf and McIntosh) and additional plants under development (Norton and Matagordo). Table 15-3 provides project information and design features for each of these CAES plants.

Huntorf Plant

The Huntorf plant (Figure 15-9) is the first compressed air storage power station in the world. It began commercial operation December 1978. Today, E.ON Kraftwerke of Bremen, Germany owns the 290 MW_{ac} CAES plant in Huntorf, Germany [14]. 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 MW_{ac} and the airflow supplied by the caverns decreases (although the plant will produce power at an exponentially declining power level for over 10 more hours).

McIntosh Plant

The 110 MW_{ac} McIntosh plant (Figure 15-10), owned by the Alabama Electric Cooperative, is the second CAES power plant in the world, and the first in the U.S. [18, 26]. Dresser-Rand designed and constructed the entire 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 [18]. 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 19 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. Dual-fuel combustors are capable of burning natural gas or fuel oil [19]. 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%.

Table 15-3
Current and On-Going CAES Development Efforts

Characteristic	Huntorf Plant [14]	McIntosh Plant	Norton Plant	Matagordo Plant [15]
Major Players	ABB, KBB (Cavern)	Dresser-Rand, PBKBB (Cavern)	Norton Energy Storage LLC	Ridge Energy Storage, Dresser-Rand
Partners and Investors	E.ON Kraftwerke (owner), NWK/Prussia Electric	Alabama Electric Cooperative	Haddington Ventures[1a] CAES Development Company LLC[1b] Haddington Energy Partners and Haddington Chase Energy Partners[1c]	-----
Amount Invested (2002 dollars)	$116 million ($400/kWe)[2]	$45.1 million ($410/kWe)[3]	$1.2 billion ($444/kWe [16])	$243 million ($450/kWe)
Schedule	Commissioned December 1978	Commissioned June 1, 1991[17]	Expected 2005/6 [25]	-----
Hurdles	Initial materials problems in the production string pipe sections	-----	-----	-----
Applications	(1) Peak shaving (2) Spinning res. (3) VAR support	(1) Arbitrage (2) Peak shaving (3) Spinning reserve	(1) Mid range generation (2) Peak shaving (3) Arbitrage	(1) Arbitrage (2) Peak shaving
Rated output	290 MW	110 MW (minimum output of 10 MW)	2,700 MW	540 MW (minimum output of 60 MW)
Duration	4 hours	26 hours	30 hours (estimate)	-----
Availability	90% [17]	95%[6] [17]	-----	-----
Starting reliability	99%	99%[7]	-----	-----
Power Requirement.	0.82 kWin / kWout	0.75 kWin / kWout	0.65 kWin / kWout	0.72 kWin / kWout
Normal Start	8 minutes	10-12 minutes[25]	-----	14 minutes

NOTES:

1. (a) Investor; (b) Developer; (c) Backers.

2. Based on an estimate of $400/kW[17], which is based on what the plant would cost using 2002 technology.

3. Plant cost $51M in 1991 dollars. Dollars shown are what this type of plant would cost in 2002 using 2002 equipment costs.

4. Actual construction time was 2.5 yrs.

5. Approval process began in early 2001.

6. During 2000-2002; overall availability since commissioning is 90% due to earlier problems now remedied.

7. In the years 2000 to 2002

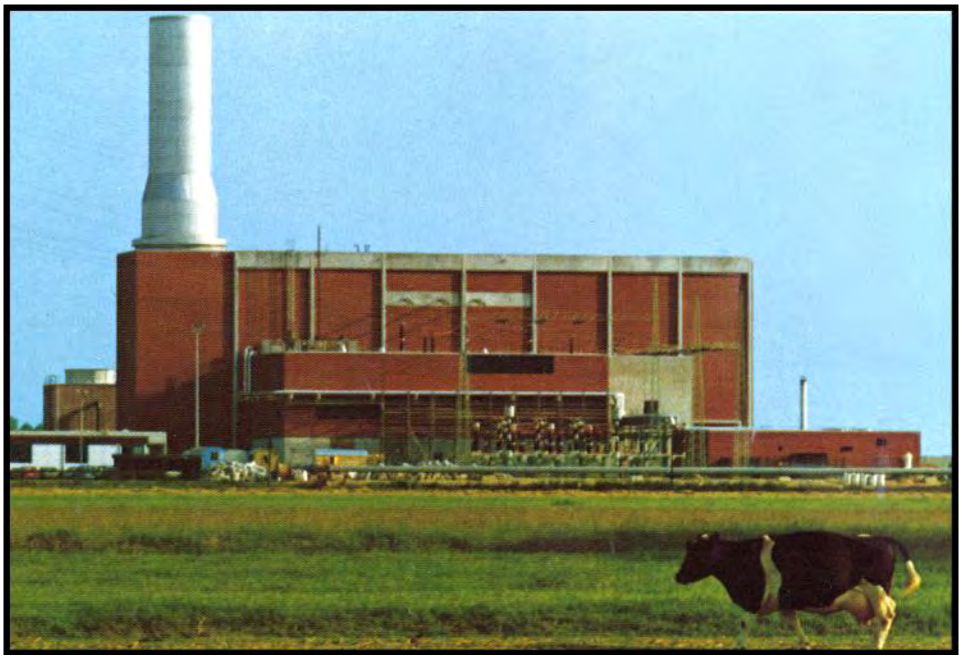

Figure 15-9
Huntorf Plant

Figure 15-10
McIntosh Plant

Norton Plant

The Norton CAES power plant (illustrated in Figure 15-11) will be the world's largest at 2,700 MW_{ac}, when it is fully completed. It is anticipated that the first 300 MW_{ac} unit will come on line in 2005 [20] to 2006 [17]. Norton Energy Storage LLC is constructing this CAES plant in Norton, Ohio. The site and the limestone mine were purchased in October 1999, four years before the anticipated startup date. The compressed air is stored in an abandoned limestone mine at a depth of 2,200 feet below the surface with a total volume of 338 million cubic feet. The cavern air pressure will range between 800 to 1,600 psi during operation. A team from Sandia National Laboratories and The Hydrodynamics Group LLC has performed a geotechnical study that concluded that "the mine will likely hold air at the required storage pressures and will work well as an air storage vessel for the CAES power plant" [20].

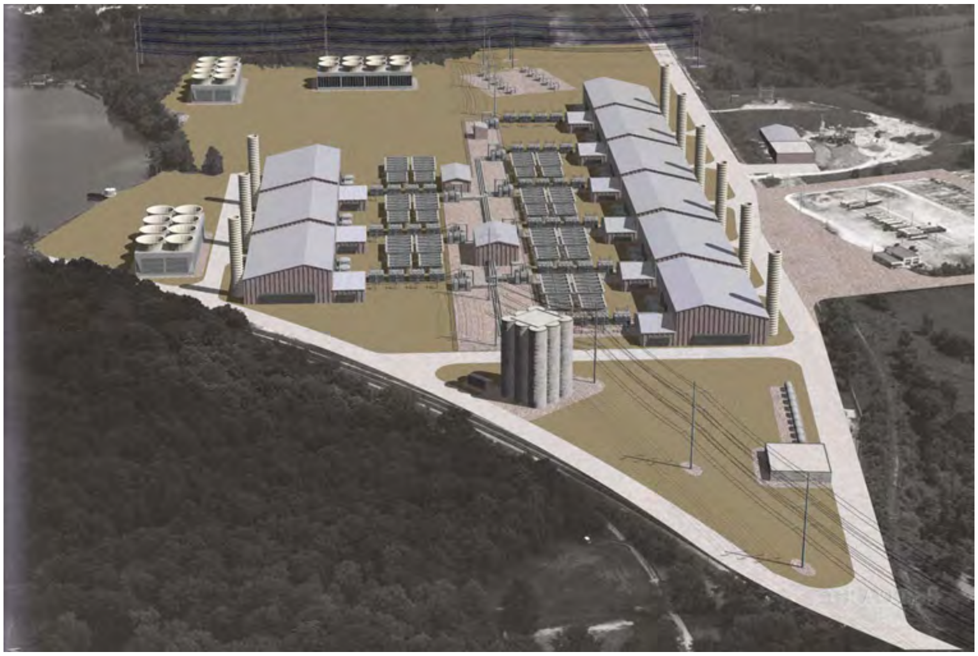

Figure 15-11
Norton Plant (Artist's Rendering)

Matagorda Plant

Houston-based Ridge Energy Storage recently began the development process for a 540 MW_{ac} CAES plant in Matagorda, Texas. The plant will use an upgraded version of the Dresser-Rand design utilized at the McIntosh plant. The design calls for four independent 135 MW_{ac} power train modules; each can reach full power in 14 minutes (or 7 minutes for an emergency start). The compressed air will be stored in a previously developed brine cavern and delivered to the expander at a pressure of 700 psi and a flow rate of 400-407 lb/sec. The heat rate of the Matagordo plant at full load is 3,800 Btu/kWh. At 20% of full load, the plant heat rate is still very favorable at 4,100 Btu/kWh. The total cost of the plant is estimated to be $243 million or $450 per kilowatt.

Other Ongoing Development Efforts

Several companies in the U.S. are committed to the development of CAES projects:

- CAES Development Company, the parent of Norton Energy Storage, is actively seeking other suitable CAES locations in the U.S.
- Strata Power owns the reservoir rights to numerous aquifers near Chicago; several CAES plants are under consideration at these sites.
- The New Energy Foundation (NEF) has led CAES development in Japan with the construction of a 2 MW_{ac}, 4-hour CAES pilot plant in Kamisunagawa-cho, Sorachigun, Hokkaido. Compressed air is stored at 580-1,160 psi in a shaft of an old coalmine. Research is ongoing to perform a comprehensive evaluation of the performance of the pilot plant. NEF

is also collaborating with the Japanese utility Electric Power Development Company Ltd. (EPDC) to develop a 35 MW_{ac}, 8-hour CAES plant.

Current Developers and Vendors

As mentioned above, several companies have been formed to focus on the development of CAES projects. The major components, the intercooled turbocompressor and reheat turboexpander trains, are commercially offered by a number of suppliers:

- Dresser-Rand offers a 135 MW_{ac} turboexpander.
- Alstom (that acquired ABB's turbine business) offers a 300-400 MW_{ac} turboexpander.
- Dresser-Rand and Sulzer offer full turbocompressor trains.

These companies are driving technical aspects of the CAES technology, and all have significant experience in this field:

- Dresser-Rand supplied the complete 110 MW_{ac} turbomachinery train for the McIntosh plant.
- ABB supplied the turboexpander for the Huntorf plant.
- Sulzer supplied the turbocompressor for the Huntorf plant.

The other components for CAES plants are obtained from vendors of conventional equipment items such as electric motors/generators, small air compressors, recuperators, etc. Table 15-4 provides a list of CAES developers and equipment vendors.

Field Tests

Before a CAES project can be developed, it is important to conduct field tests to determine the feasibility of a site for a full-scale plant. For example, significant drilling work and probe analyses were conducted before the McIntosh plant was constructed to determine the salt characteristics and the configuration of the salt dome.

Table 15-4
Current Developers and Vendors

Company	Role
Allison	10-20 MW_{ac} turboexpander train
Alstom/ABB	300-400 MW_{ac} turboexpander train manufacturer
Dresser Rand	135 MW_{ac} turboexpander train manufacturer
Mitsubishi	30-150 MW_{ac} turboexpander train manufacturer
CAES Development Company	Project developer, U.S.
Decker Energy International	Project Developer, U.S.
Reliant	Project developer, U.S.
New Energy Foundation	Project developer, Japan
Ridge Energy Storage	Project developer, U.S.
Haddington Ventures, L.L.C.	Project developer, U.S.
Strata Power	Project developer, U.S.
Siemens Westinghouse	150-300 MW_{ac} turbomachinery
PB Energy Storage Services	Salt geology air stores
Geo-Stock	Porous media, salt geology

Several companies and/or organizations have conducted CAES field tests to determine the competency of reservoirs or to demonstrate pilot plants. Table 15-5 provides details of three such examples in Japan, Italy, and the U.S.

Japan

In Japan, the Energy Storage Engineering Development Center (under the New Energy Foundation) has constructed a 2-MW_e pilot CAES plant in a tunnel in the former Sunagawa Coal Mine in Kami-sunagawa Town, Sorachi-gun, Hokkaido Prefecture. Constructional and operation research has been conducted since 1990 to evaluate plant performance for load leveling [21]. The air is stored in a 187-foot long tunnel lined with 2.3 feet of concrete and a synthetic liner tunnel, which has an inside diameter of 19.7 feet. The aboveground equipment consists of the following:

- Oil-less, 4-stage reciprocating compressor
- Single cylinder combustion chamber

- Simple open-cycle single-shaft gas turbine
- Gas turbine power generator
- Steel-finned tube regenerator to preheat the combustion air using exhaust heat recovery
- Cooling water system with air-cooled radiator
- No NO_x reduction equipment

Table 15-5
CAES Field Tests

Characteristic	Location		
	Japan [21]	**Italy**	**Pittsfield**
Sponsor	**New Energy Foundation**	**ENEL**	**Strata Power, EPRI, Nicor, DOE**
Storage	Variable pressure using synthetic lining in concrete shaft put in coal mine tunnel	Porous rock	Porous sandstone caverns
Design parameters	2 MW_{ac} 10 hours compression 4 hours generation 1,100 psi 57,000 cubic feet	25 MW_{ac}	Testing successfully completed to measure and cycle stored compressed air
Status	On-going project	Air Cyclic Testing Successful (geologic formation was “disturbed” by a nearby geothermal event and the extra testing was stopped somewhat prematurely)	Testing successful [22]

Italy

ENEL operated a small 25 MW_{ac} CAES research facility plant in Italy using a porous rock storage zone that previously held a carbon dioxide “bubble” near a geothermal region. Although the initial air cyclic testing was successful, the extra testing was stopped somewhat prematurely when the geologic formation was “disturbed” by a geothermal event (which was probably induced by a nearby geothermal field extraction process).

United States

Several parties, including Strata Power, EPRI, Nicor, and U.S. DOE, have tested the porous sandstone caverns in Pittsfield, Illinois to determine the feasibility of the porous rock formations for holding and cycling compressed air. The tests that EPRI performed at the Pittsfield site (after taking over the project from DOE when their funding was constrained) indicated that compressed air could be stored and cycled successfully in the St. Peter sandstone underneath the Pittsfield site. However, if air is left in this sandstone for more than three months before it is cycled, the stored air starts to react with local pyrites in the sandstone, causing a reduction in the concentration of oxygen. It has been hypothesized that, at some point, the oxidation process would be self-limiting at the site.

Lessons Learned

During construction and initial operation of the McIntosh and Huntorf plants, the project participants conducted a number of optimization studies and analyses related to various aspects of the CAES plant engineering and operations. The lessons learned – some of them of a conceptual nature and some related to engineering details – have been presented in technical publications [23] and EPRI reports [25].

The generic conceptual findings are summarized as follows:

- CAES plants can be built within estimated costs and schedule.
- The plants confirmed the expected high efficiency, reliability, availability, and competitive economics.
- The underground storage caverns were developed using well-established techniques and were completed on time within budgeted funds.
- Careful optimization of the CAES plant design can significantly enhance plant economics. For example, the McIntosh plant was optimized based on specified off-peak and on-peak hours, off-peak and on-peak power costs, fuel costs, and cost equations describing equipment and storage costs as a function of major cycle parameters.
- The recuperator requires a particular care in its design. The so-called Advanced Recuperator [11] is used to prevent the tubes from operating at temperatures below the exhaust air dew point.
- Underground storage reservoirs can achieve negligible leak rates. In fact, no air leakage has been measured at either the Huntorf or McIntosh plants since they were commissioned.
- The negligible amount of sodium chloride in the compressed air drawn from salt caverns does not cause corrosion problems in the aboveground turbomachinery equipment.
- The role of the house engineer involved in the CAES project is very important because there is no standard CAES plant. To minimize plant costs and to enhance the plant performance and operations, the house engineer should integrate and optimize the aboveground and underground components and systems for the specific site conditions and economic parameters of the plant owner.
- CAES plants can be constructed using commercially available equipment; mainly components developed for the combustion turbine and oil/gas industries over that last 50 years.

Unresolved Issues

However, several advances in the CAES technology have yet to be demonstrated or tested in the field environment. The following concepts offer significant theoretical advantages but require practical validation:

- Demonstrate air storage in porous rock and in hard rock storage formations
- Demonstrate surface piping and costs for air storage CAES application
- Demonstrate the CAES plant concept with storage of thermal energy -- recover the thermal energy from the heat of compression to reheat the air withdrawn from storage many hours later
- Demonstrate a “hybrid” CAES plant [12]

Summary of Innovative Development Efforts

The conventional single-shaft configuration for a CAES plant was used for the McIntosh and Huntorf projects. The compressors, motor/generator, and expanders are all on the same shaft, separated by clutches. This low initial capital cost concept requires only a single motor / generator that supports both the compression and power generation cycles. The expanders can be used to start the compressor train. The advanced recuperator used in the McIntosh plant is a necessary component to reduce the heat rate, and the plant is operating much of the time. Dresser-Rand is a promoter of the conventional configuration as well as other plant configurations.

OEMs and developers are also promoting several innovative CAES plant concepts; the innovation lies in the use of present day turbo-expanders, compressors, new thermal cycles, different turbomachinery configurations, and different component selection. The innovative development efforts are summarized in Table 15-6 and described in the text below.

- Innovative Concept 1 -- This multi-shaft concept includes a reheat expander train (with a recuperator) driving the electric generator for peak power generation and a number of parallel independently operating motor-driven intercooled compressors trains for charging the underground storage. This concept has higher capital costs but provides significant operating flexibility. This concept is currently under consideration for a number of projects. Both Dresser Rand and Alstom commercially offer this configuration.
- Innovative Concept 2 – In this concept, a high-pressure recuperator is used instead of the high-pressure combustor in the expansion train. The only combustor is a conventional low-pressure combustor installed upstream of the low-pressure turbine. This concept eliminates the high-pressure combustor, which is a relatively new and a technically challenging component. Alstom is promoting this concept for 300-400 MW_e CAES plants.

Table 15-6
Innovative Development Efforts

Characteristic	Innovative Concept 1	Innovative Concept 2	Innovative Concept 3	Innovative Concept 4
Feature	Multiple independent compressor trains	High-pressure recuperator	Preheat air upstream of combustion turbine	Compress air using wind power
Status	Commercially available	Commercially available	Design being marketed	Being studied
Target market	Plants requiring operating flexibility	300-400-MW_e plants requiring high reliability	Plants requiring high peak power and operating flexibility	Wind farms
Potential Funding	EPRI, DOE, IPPs, venture capitalists	EPRI, DOE, IPPs, venture capitalists	EPRI, DOE, IPPs, venture capitalists	EPRI, DOE, IPPs, venture capitalists
Vendors	Dresser-Rand, Alstom	Alstom	Alstom	Dresser-Rand, Alstom
Demonstrations	Funded in the future	Funded in the future	Funded in the future	Funded in the future
Development trends	Operational flexibility	Produces lower emissions	Provides higher peak power	Integration with wind energy
Issues	High first cost	Reliability of high-pressure recuperator	System control and heat balance	Power fluctuation from wind, cost of aboveground compressed air storage

- Innovative Concept 3 -- Alstom is marketing the concept of adding an air turbine upstream of the combustion turbines [24]. A recuperator recovers the heat in the low-pressure expander exhaust and preheats the compressed air from the cavern to approximately 900°F. The preheated compressed air is expanded through an air turbine to drive a generator in addition to the power generated by a GT24/GT11 combustion turbine. The combustion turbine and the air turbine can generate more power than the combustion turbine alone. The compressor train consists of a number of motor-driven intercooled compressors operating in parallel to charge the underground storage. This concept has the advantages of high peak power, proven components, excellent operating flexibility, reliability, and availability, and competitive costs. Innovative Concept 4 -- There are a number of studies investigating the integration of wind farms with small capacity CAES plants. The concept is to use the wind power (primarily during night hours) to compress the air for storage in above ground piping and/or other pressure vessels. During peak hours of electric demand, the compressed air supplies a combustion turbine to generate electric power for sale at premium prices. Since the compression is independent of the power generation, this hybrid plant can operate continuously to provide base load power in addition to the intermittent peak load.

T&D System Energy Storage System Applications

General CAES Applications and Costs

CAES plants designed for specific applications can provide economic benefit to owners and/or operators of power generation facilities, and transmission and distribution (T&D) facilities. The benefits of using a CAES plant to support power generation include the following:

- Increase use of generation facilities during off-peak hours (i.e., during the storage plant charging cycle)
- Provide ramping, intermediate, and peaking power during the day.
- Store nighttime wind energy for delivery during the higher priced daytime hours (a remote wind farm would be an excellent application for CAES since air can be compressed at night when excess wind energy is most available).
- Provide frequency regulation (CAES can provide much better frequency control than a base-load power plant).

The benefits of using a CAES plant for T&D support include the following:

- Provide VAR support (e.g., by operating the CAES plant to supply reactive power in the synchronous condenser mode). A CAES plant can be operated 24 hours a day in the synchronous condenser mode, since it does not require any air from the storage reservoir.
- Provide peak shaving to enable deferment of T&D upgrades (e.g., by siting surface-based CAES plants near load centers). This application has a very large benefit-to-cost ratio.
- Provide area control to reduce energy imbalances between grid regions.
- Provide spinning reserve. This application has twice the spinning reserve capability (MW) during the charging cycle time since the grid operator gets credit for the power off-loaded during the charge cycle in addition to the plant generation capacity.
- Provide supplemental reserve. This application has twice the spinning reserve capability (MW) during the charging cycle time since the grid operator gets credit for the power off-loaded during the charge cycle in addition to the plant generation capacity.
- Provide off-peak-on-peak arbitrage
- Provide ramping power when the demand on a feeder or substation increases at a higher rate than the other generating capacity can ramp.
- Absorb excess generating capacity with its compressor during times of rapidly decreasing demand. This application is particularly useful when base nuclear, hydro, or fossil capacity is available at very low prices during off peak time periods.

In the classical configuration, a CAES plant would be connected to a grid that has access to off-peak charging energy from a power generating plant that is underutilized during the off-peak hours. However, at least one of the advanced CAES cycles uses the plant itself to charge the air storage media.

The capital cost of a CAES plant is a function of the storage medium, the plant capacity (power), and the energy stored in the storage medium. Table 15-7 below gives approximate values for the capital cost components of reference CAES plants as a function of some of the plant variables. These data, along with representative operating costs, were used in the assessment of potential CAES applications described in the following sections.

Table 15-7
Representative CAES Plant Capital Costs [26]

Storage Media for CAES Plant	Size (MW_{ac})	Cost for Power-Related Plant Components ($/kW)	Cost for Balance of Power Plant ($/kW)	Cost for the Energy Storage Components ($/kWh)	"Typical" Hours of Storage for a Plant	Total Cost ($/kW)
Salt	300	270	170	1 (Note 1)	10	450
Surface Piping (Note 2)	10	270	160	40	3 & 10	550 & 830

Notes:
1. The reference energy storage capacity for large CAES technologies is 10 hours. A representative price for CAES systems over the range of 8 to 20 hours storage can be obtained by applying increments/decrements at the rate of $1/kWh.
2. Costs for CAES plants using surface piping are based on the assumption that codes and standards used within the gas piping industry are applicable. This assumption and the associated cost projections are subject to confirmation.

Select Applications for CAES Systems

This section presents the applications for which CAES systems are suited and describes the key features of CAES systems configured to meet the requirements of the selected applications. Screening economic analyses have shown that both small and large CAES systems are potentially competitive for two of the single function applications as well as one of the combined function applications. Applications are described in detail in Chapter 3. The following list briefly summarizes and reiterates key requirements for all applications. Those for which CAES is best suited are enclosed by borders. This list identifies the applications for which both small (e.g., 10 MW_{ac} with 3 and 10 hour pipeline piping storage) and large (e.g., 135 or 300 MW_{ac} with 10-hour geologic salt dome storage) CAES systems are evaluated.

Single Function Applications

Application A: Grid Angular Stability (GAS) – mitigation of power oscillations by injection and absorption of real power at periods of 1 to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 20 oscillatory cycles, cumulatively equivalent to a full power discharge (FPD) of 1-second duration and subsequent charge cycle; 1 event per day; 10 events per year. Valued at the cost of alternative solutions.

Application B: Grid Voltage Stability (GVS) – mitigation of degraded voltage by additional reactive power plus injection of real power for durations up to 2 seconds. The reference duty cycle for analysis is standby for infrequent events characterized by 1 second FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application C: Grid Frequency Excursion Suppression (GFS) – "prompt" spinning reserve (or load) for mitigating load-generation imbalance. Requires energy storage to discharge real power for durations up to 30 minutes. The reference duty cycle for analysis is standby for infrequent events characterized by 15-minute FPD, 1 event per day, 10 events per year. Valued at the cost of alternative solutions.

Application D: Regulation Control (RC) – system frequency regulation in concert with load following. The reference duty cycle for analysis is characterized by continuous cycles equivalent to 7.5-minute FPD and charge cycle (triangular waveform), 2 cycles per hour deployed with 10 minutes advance notice. Valued at market rates.

e.g., large CAES at 135 or 300 MW_{ac}

Application E: Spinning Reserve (SR) – reserve power for at least 2 hours with 10 minute notice. The reference duty cycle for analysis is standby for infrequent events characterized by 2-hour FPD, 1 event per day, 10 events per year. Valued at market rates.

Application F: Short Duration Power Quality (SPQ) – capability to mitigate voltage sags (e.g., recloser events). The reference duty cycle for analysis is standby for infrequent events characterized by 5 seconds FPD, 1 event per hour, 5 events per day, 100 events per year. Valued at the cost of alternative solutions.

Application G: Long Duration Power Quality (LPQ) – SPQ, plus capability to provide several hours reserve power. The reference duty cycle for analysis is standby for infrequent events characterized by SPQ plus standby for 4 hours FPD, 1 event per year. Valued at the cost of alternative solutions.

Application H: 3-hr Load Shifting (LS3) – shifting 3 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 3-hour FPD, 1 event per day, 60 events per year. Valued at market rates.

e.g., small CAES at 10 MW_{ac}

Application I: 10-hr Load Shifting (LS10) – shifting 10 hours of stored energy from periods of low value to periods of high value. The reference duty cycle for analysis is scheduled 10-hour FPD, 1 event per day, 250 events per year. Valued at market rates.

e.g., small CAES at 10 MW_{ac} and large CAES at 135 or 300 MW_{ac}

Combined Function Applications (In the Order Noted)

Application C1: Combined Applications C, A, B, D (GFS +GAS + GVS + RC)

Application C2: Combined Applications F, I, D, E (SPQ + LS10 + RC + SR)

Application C3: Combined Applications F, H, D, E (SPQ + LS3 + RC + SR)

Application C4: Combined Applications G, H, D, E (LPQ + LS3 + RC + SR)

Application C5: Combined Applications I, D, E (LS10 + RC + SR)

e.g., small CAES at 10 MW_{ac} and large CAES at 135 or 300 MW_{ac}

Assessment of Small (10 MW_{ac}) CAES Systems

Small (10 MW_{ac}) CAES System Compliance With Application Requirements

The CAES system performance parameters discussed above were used to develop approximate sizes and operational parameters for systems meeting the application requirements for the selected CAES applications described in the previous section. Performance aspects of CAES systems for the selected applications are described below and summarized in Table 15-8. The reference power for applications in this section is 10 MW_{ac}.

- Application H: 3-hr Load Shifting (LS3) – This application requires that the system provide load shifting for 3 hours per day at 10 MW_{ac} for 60 days per year on a scheduled basis, i.e., response is required within 10 minutes.
- Application I: 10-hr Load Shifting (LS10) – This application requires that the system provide load shifting for 10 hours per day at 10 MW_{ac} for 250 days per year on a scheduled basis, i.e., response is required within 10 minutes.
- Application C5**:** Combined Applications I, D, E (LS10 + RC + SR) – This application requires that the system provide 10-hour load shifting, regulation control and spinning reserve functions on a scheduled basis. Load shifting is provided for 10 hours per day at 10 MW_{ac} for 250 days per year, plus RC and SR at 10 MW_{ac}. RC is provided for 16 hours per day, 105 days per year, and SR for the remainder of the year.

Table 15-8
Small (10 MW_{ac}) CAES System Compliance With Application Requirements

Applications	Single Function: App H: LS3 -- 3 hr FPD per cycle, 60d/yr	Single Function: App I: LS10 -- 10 hr FPD per cycle, 250d/yr	Combined Function: App C5: LS10 + RC + SR
Storage Designation	10MW-3h	10MW-10h	10MW-10h
Power Plant			
Combustion Turbine	CT		
Duty Cycles			
Grid Support or Power Quality (GS or PQ)			
Power, MW			
Event Duration, Hr			
Load Shifting (LS)			
Power, MW	10	10	10
Hours per day, hr	3	10	10
Days per year, days	60	250	250
Load Shift Energy, MWh/yr	1,800	25,000	25,000
Regulation Control (RC)			
Power, MW			10
Hours per day, hr			16
Days per year, days			105
RC, MW-Hours/yr			16,800
Spinning Reserve (SR)			
Power, MW			10.0
SR, MW-Hours			15,120

Benefit and Cost Analyses for Small (10 MW_{ac}) CAES

CAES Pricing and Integrated System Costs

The installed costs for 10 MW_{ac} CAES with 3 and 10 hours storage are $5.5 and 8.3 million, respectively. Both units use piping designed to natural gas transmission and distribution pipeline standards to stored compressed air. Capital and operating costs are summarized in Table 15-9, where initial costs include acquisition, space and installation costs; fixed O&M costs include projected annual costs for parts and labor, plus annual property taxes and insurance (based on 2% of the initial total capital costs); and variable O&M costs include costs for fuel and other variable consumables.

Table 15-9
Capital and Operating Costs for Small (10 MW_{ac}) CAES Systems

Applications	Single Function		Combined Function
	App H: LS3 -- 3 hr FPD per cycle, 60d/yr	**App I: LS10 -- 10 hr FPD per cycle, 250d/yr**	**App C5: LS10 + RC + SR**
CAES Storage Capacity, MWhac	30	100	100
CT Initial Cost, $/kW	270	270	270
BOP Initial Cost, $/kW	160	160	160
CAES Storage Initial Cost, $/kW	120	400	400
CAES Storage Cost, $/kWh	40	40	40
Total Capital Cost, M$	5.5	8.3	8.3
O&M Cost – Fixed, $/kW-year	19.0	24.6	24.6
O&M Cost– Variable, $/kW-year	4.7	65.0	69.3

Note: The total initial cost may be calculated in two ways:
1. By mutiplying the sum of PCS, BOP and Battery initial costs expressed in $/kW by the reference power,
2. OR by mutiplying the sum of PCS and BOP expressed in $/kW by the reference power and then adding the product of Battery Initial cost expressed in $/kWh and the Battery Capacity

As a rule of thumb for a "generic" CAES plant, the operating cost per kWh delivered during power generation mode is the factor "K" times that of the incremental cost per kWh of off-peak power purchased during the compression mode, plus the cost of the fuel (in $/MMBtu) times the plant heat rate, "H_R". For the purposes of evaluating 10 MW_{ac} CAES configuration, K and H_R have been defined as 0.75 and 4200 Btu/kWh, respectively, i.e.:[26]

Cost of electricity generated ($/kWh) = (0.75) (Incremental cost of electricity purchased, $/kWh) + (Cost of fuel purchased, $/MMBtu) (4,200 Btu/kWh) / (1,000,000 Btu/MMBtu)

The factor, K, 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. The heat rate, H_R, is typical for an expander-generator set operating without the compressor during the generation mode.

For 10 MW_{ac} CAES, fixed O&M costs are based on $8/kW-year, plus property taxes and insurance; and variable O&M costs are based on $0.005/kWh, plus fuel costs calculated for a heat rate of 4,200 Btu/kWh and natural gas fuel priced at $5/MMBtu.

Lifecycle Benefit and Cost Analysis for Small (10 MWac) CAES Systems

Further insight to the value of energy storage can be gained through lifecycle cost analyses using a net present value (NPV) methodology and comparison with alternatives. For the convenience of the reader, the financial parameters and electric rate structure set forth in Chapters 4 and 5 and used in the analyses are summarized in Table 15-10 and Table 15-11.

Table 15-10
Financial Parameters

Dollar Value	2003
System Startup	June 2006
Project Life, years	20
Discount Rate (before tax), %	7.5
Property Taxes & Insurance, %/year	2
Fixed Charge Rate, %/year	9.81

Table 15-11
Electric Rates

Load Shifting On Peak Period	3	10
Number Cycles per year	60	250
On-Peak Energy, $/MWh	120	80
Off-Peak Energy, $/MWh	20	
Yearly Average Energy Charge, $/MWh	38	
Regulation Control, $MW-Hour (power), $/MWh	16	
Spinning Reserve, $MW-Hour (power), $/MWh	3	
Transmission Demand Charge, $/kW-mo	5	
Natural Gas, $/MMBtu	5	

The results of lifecycle cost benefit analyses of select CAES applications are summarized in Table 15-12 and discussed below. The bases and methodology used in valuing energy storage applications are described in detail in Chapter 4. The details of the cost benefit analysis for each application are discussed below.

Table 15-12
Summary of Benefit and Cost Analyses of Small (10 MW_{ac}) CAES Systems

Applications	Single Function		Combined Function
	App H: LS3 -- 3 hr FPD per cycle, 60d/yr	App I: LS10 -- 10 hr FPD per cycle, 250d/yr	App C5: LS10 + RC + SR
Alt Solution Value, $/kW	750	750	750
Storage Designation	10MW-3h	10MW-10h	10MW-10h
Initial Installed Cost, M$	5.5	8.3	8.3
Total Costs, M$	(7.9)	(17.4)	(17.9)
Total Benefits, M$	10.9	40.4	43.6
Benefit to Cost Ratio	1.4	2.3	2.4
NPV, M$	3.0	22.9	25.7

- Application H: 3-hr Load Shifting (LS3) – This application was evaluated on the assumption that an alternative solution capable of avoiding upgrade costs can be obtained for net capitalized costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. In addition, the benefits of market rates for on-peak energy and demand charges and off-peak energy rates to replenish compressed air are included. As shown in Table 15-12, this application yields a NPV of $3.0 million for an initial investment of about $5.5 million, corresponding to a total benefit to cost ratio of 1.4. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 15-12 illustrates the change in NPV over a range of $500 to $1000/kW and shows that small CAES systems with 3 hours stored energy will compete favorably against alternative solutions over this range.

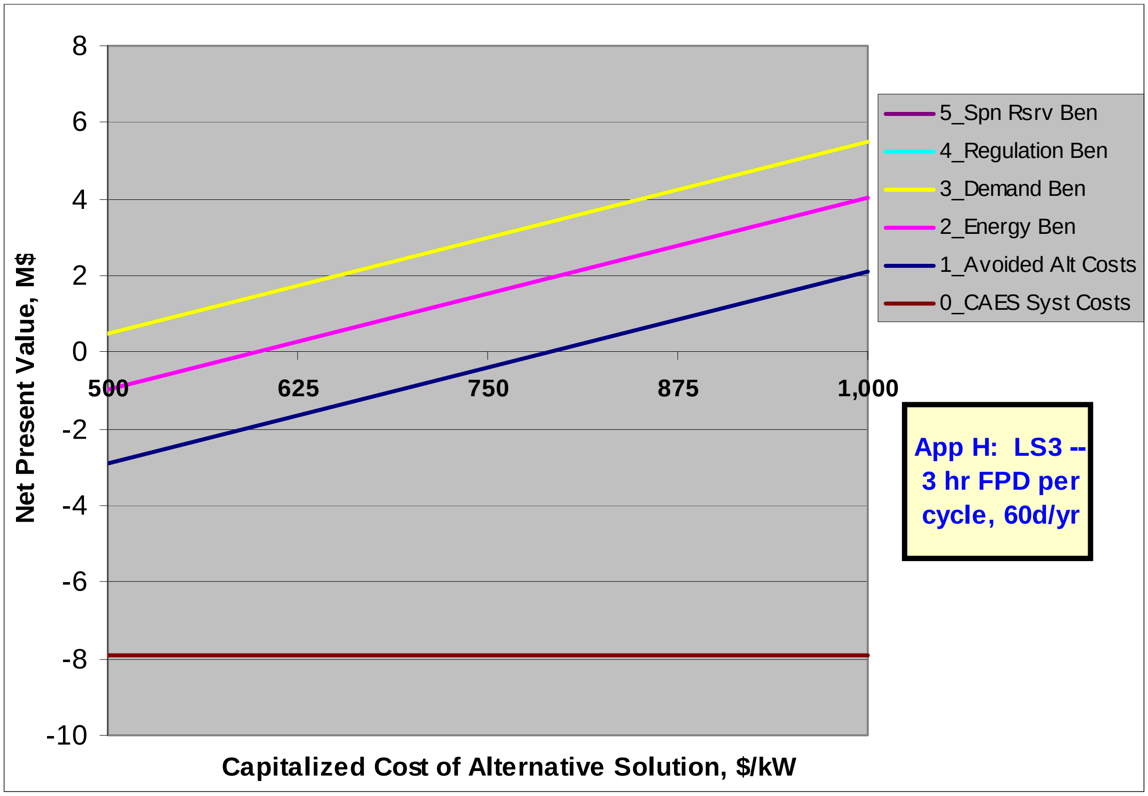

Figure 15-12
Application H: Small (10 $MW_{ac,}$ 3 Hr Storage) CAES System NPV vs Cost of Alternative Solution

- Application I: 10-hr Load Shifting (LS10) – This application was evaluated on the assumption that an alternative solution capable of avoiding upgrade costs can be obtained for net capitalized costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. In addition, the benefits of market rates for on-peak energy and demand charges and off-peak energy rates to replenish compressed air are included. As shown in Table 15-12, this application yields a NPV of $22.9 million for an initial investment of about $8.3 million, corresponding to a total benefit to cost ratio of 2.3. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 15-13 illustrates the change in NPV over a range of $500 to $1000/kW and shows that small CAES systems with 10 hours stored energy will compete favorably against alternative solutions over this range.

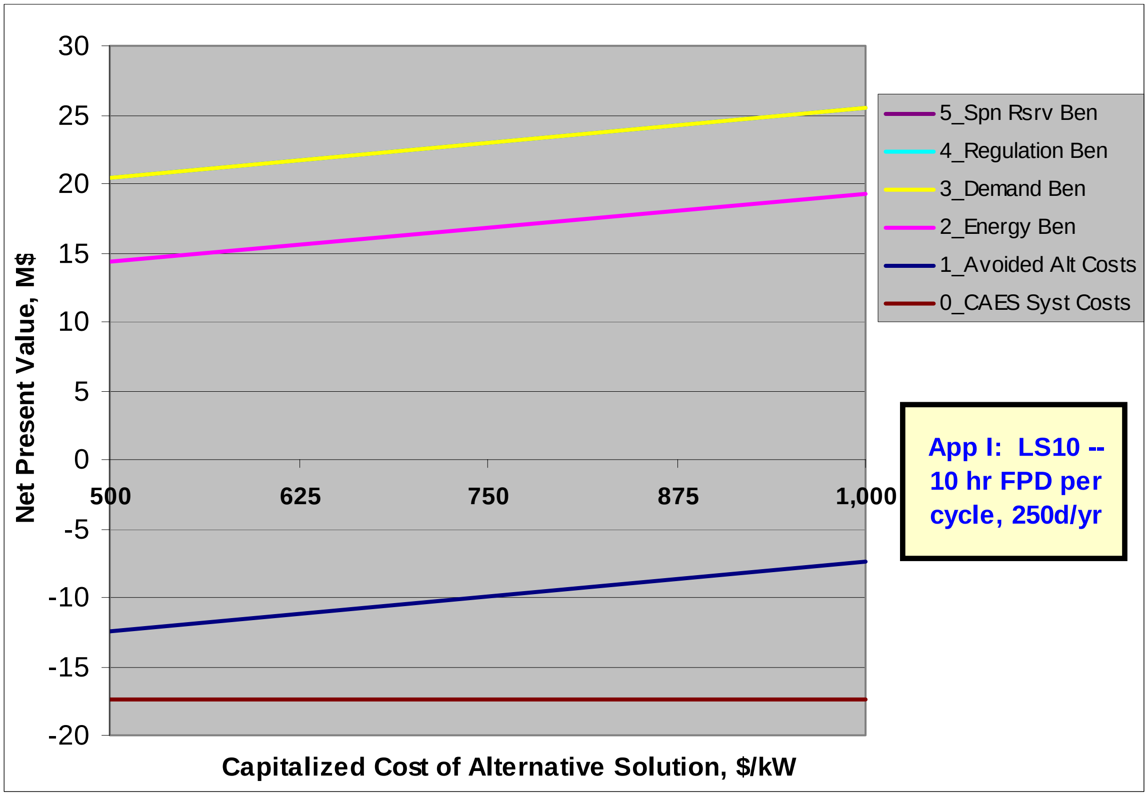

Figure 15-13
Application I: Small (10 $MW_{ac,}$ 10 hr storage) CAES System NPV vs Cost of Alternative Solution

- Application C5: Combined Applications I, D, E (LS10 + RC + SR) – This application was evaluated on the assumption that an alternative to LS10 related upgrade costs can be obtained for net capitalized costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. In addition, market rates for 10-hour load shifting, regulation control, and spinning reserve are included in the valuation. As shown in Table 15-12, this application yields a NPV of $25.7 million for an initial investment of about $8.3 million, corresponding to a total benefit to cost ratio of 2.4. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 15-14 illustrates the change in NPV over a range of $500 to $1000/kW and shows that small CAES systems with 10 hours stored energy will compete very favorably against alternative solutions over this range.

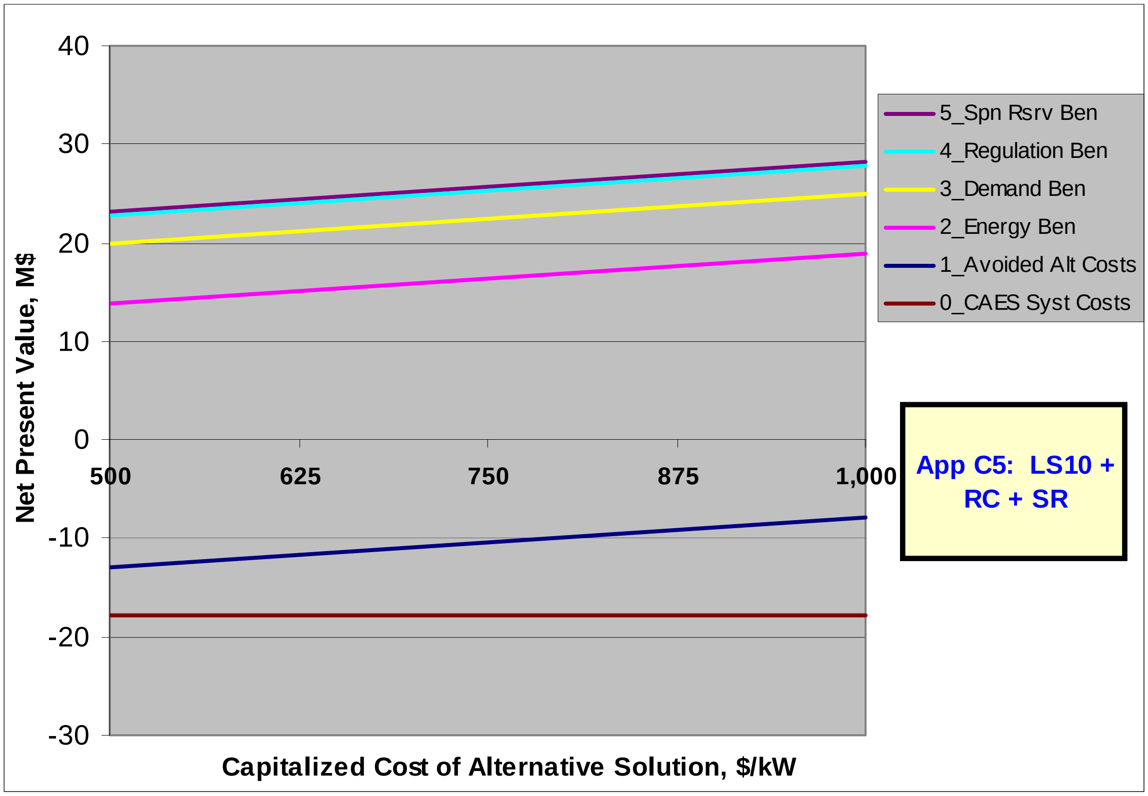

Figure 15-14
Application C5: Small (10 $MW_{ac,}$ 10 Hr Storage) CAES System NPV vs Cost of Alternative Solution

Assessment of Large (135 and 300 MW_{ac}) CAES Systems

Large CAES systems are currently being marketed with one or more turbine systems in the range of 135 MW_{ac} and 300 MW_{ac}. While the reference power was chosen to be 300 MW_{ac}, the results of calculations presented herein apply to both when expressed on a per unit basis (e.g., $/kW, $/kWh). The reference stored energy for large CAES is 10 hours discharge duration.

Large (300 MW_{ac}) CAES System Compliance With Application Requirements

The large CAES system performance parameters discussed earlier were used to develop approximate sizes and operational parameters for systems meeting the application requirements for the selected CAES applications described in the previous section. Performance aspects of CAES systems for the selected applications are described below and summarized in Table 15-13.

- Application D: Regulation Control (RC) – This application requires that the system provide regulation control at 300 MW_{ac} on a scheduled basis, i.e., response is required within 10 minutes.

- Application I: 10-hr Load Shifting (LS10) – This application requires that the system provide load shifting for 10 hours per day at 300 MW_{ac} for 250 days per year on a scheduled basis, i.e., response is required within 10 minutes.
- Application C5**:** Combined Applications I, D, E (LS10 + RC + SR) – This application requires that the system provide 10-hour load shifting, regulation control and spinning reserve functions on a scheduled basis. Load shifting is provided for 10 hours per day at 300 MW_{ac} for 250 days per year, plus RC and SR at 300 MW_{ac}. RC is provided for 16 hours per day, 105 days per year, and SR for the remainder of the year.

Table 15-13
Large (300 MW_{ac}) CAES System Compliance With Application Requirements

	Single Function		Combined Function
Applications	**App D: RC -- 15 min FPD per cycle, 2 cycles/hr**	**App I: LS10 -- 10 hr FPD per cycle, 250d/yr**	**App C5: LS10 + RC + SR**
Storage Selection			
Geologic Salt Dome	Salt		
Power Plant			
Combustion Turbine	CT		
Duty Cycles			
Grid Support or Power Quality (GS or PQ)			
Power, MW			
Event Duration, Hr			
Load Shifting (LS)			
Power, MW		300	300
Hours per day, hr		10	10
Days per year, days		250	250
Load Shift Energy, MWh/yr		750,000	750,000
Regulation Control (RC)			
Power, MW	300		300
Hours per day, hr	16		16
Days per year, days	355		105
RC, MW-Hours/yr	1,704,000		504,000
Spinning Reserve (SR)			
Power, MW			300
SR, MW-Hours			453,600

Benefit and Cost Analyses for Large (300 MW_{ac}) CAES

CAES Pricing and Integrated System Costs

The installed costs for a 300 MW_{ac} CAES system with 10 hours storage in a subterranean geologic formation, e.g., a salt dome, are $135 million. Capital and operating costs are summarized in Table 15-14, where initial costs include acquisition, space and installation costs; fixed O&M costs include projected annual costs for parts and labor, plus property taxes and insurance; and variable O&M costs include costs for fuel and other variable consumables.

Table 15-14
Capital and Operating Costs for Large (300 MW_{ac}) CAES Systems

Applications	Single Function		Combined Function
	App D: RC -- 15 min FPD per cycle, 2 cycles/hr	App I: LS10 -- 10 hr FPD per cycle, 250d/yr	App C5: LS10 + RC + SR
CAES Storage Capacity, MWhac	2,400	3,000	3,000
CT Initial Cost, $/kW	270	270	270
BOP Initial Cost, $/kW	170	170	170
CAES Storage Initial Cost, $/kW	10	10	10
CAES Storage Cost, $/kWh	1	1	1
Total Capital Cost, M$	135	135	135
O&M Cost – Fixed, $/kW-year	13.0	13.0	13.0
O&M Cost– Variable, $/kW-year	8.5	58.8	61.3
Note: The total initial cost may be calculated in two ways: 1. By mutiplying the sum of PCS, BOP and Battery initial costs expressed in $/kW by the reference power, 2. OR by mutiplying the sum of PCS and BOP expressed in $/kW by the reference power and then adding the product of Battery Initial cost expressed in $/kWh and the Battery Capacity			

As a rule of thumb for a "generic" CAES plant, the operating cost per kWh delivered during power generation mode is the factor "K" times that of the incremental cost per kWh of off-peak power purchased during the compression mode, plus the cost of the fuel (in $/MMBtu) times the plant heat rate, "H_R". For the purposes of evaluating 300 MW_{ac} CAES configuration, K and H_R have been defined as 0.70 and 4100 Btu/kWh, respectively, i.e.:[26]

Cost of electricity generated ($/kWh) = (0.70) (Incremental cost of electricity purchased, $/kWh) + (Cost of fuel purchased, $/MMBtu) (4,100 Btu/kWh) / (1,000,000 Btu/MMBtu)

The factor, K, 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. The heat rate, H_R, is typical for an expander-generator set operating without the compressor during the generation mode.

For 300 MW_{ac} CAES, fixed O&M costs are based on $4/kW-year, plus property taxes and insurance; and variable O&M costs are based on $0.003/kWh, plus fuel costs calculated for a heat rate of 4,100 Btu/kWh and natural gas fuel priced at $5/MMBtu.

Lifecycle Benefit and Cost Analysis for Large (300 MW_{ac}) CAES Systems

Lifecycle cost analyses of large CAES systems using NPV methodology were conducted in the same manner as was done for small CAES systems in the previous section. For the convenience of the reader, the financial parameters and electric rate structure set forth in Chapters 4 and 5 and used in the analyses are summarized in Table 15-10 and Table 15-11.

The results of lifecycle cost benefit analyses of select CAES applications are summarized in Table 15-15 and discussed below. The bases and methodology used in valuing energy storage applications are described in detail in Chapter 4. The details of the cost benefit analysis for each application are discussed below.

Table 15-15
Summary of Benefit and Cost Analyses of Large (300 MW_{ac}) CAES Systems

	Single Function		Combined Function
Applications	App D: RC -- 15 min FPD per cycle, 2 cycles/hr	App I: LS10 -- 10 hr FPD per cycle, 250d/yr	App C5: LS10 + RC + SR
Alt Solution Value, $/kW	NA	750	750
Initial Installed Cost, M$	135	135	135
Total Costs, M$	(201)	(354)	(362)
Total Benefits, M$	278	1,219	1,315
Benefit to Cost Ratio	1.4	3.4	3.6
NPV, M$	77	865	953

- Application D: Regulation Control (RC) – This application was evaluated on the basis of market rates for regulation control. As shown in Table 15-15, it yields a NPV of $77 million for an initial investment of about $135 million, corresponding to a total benefit to cost ratio of 1.4.
- Application I: 10-hr Load Shifting (LS10) – This application was evaluated on the assumption that an alternative solution capable of avoiding upgrade costs can be obtained for net capitalized costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. In addition, the benefits of market rates for on-peak energy and demand charges and off-peak energy rates to replenish compressed air are included. As shown in Table 15-15, this application yields a NPV of $865 million for an initial investment of about $135 million, corresponding to a total benefit to cost ratio of 3.4. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 15-15 illustrates the change in NPV over a range of $500 to $1000/kW and shows that large CAES systems will compete favorably against alternative solutions over this range.

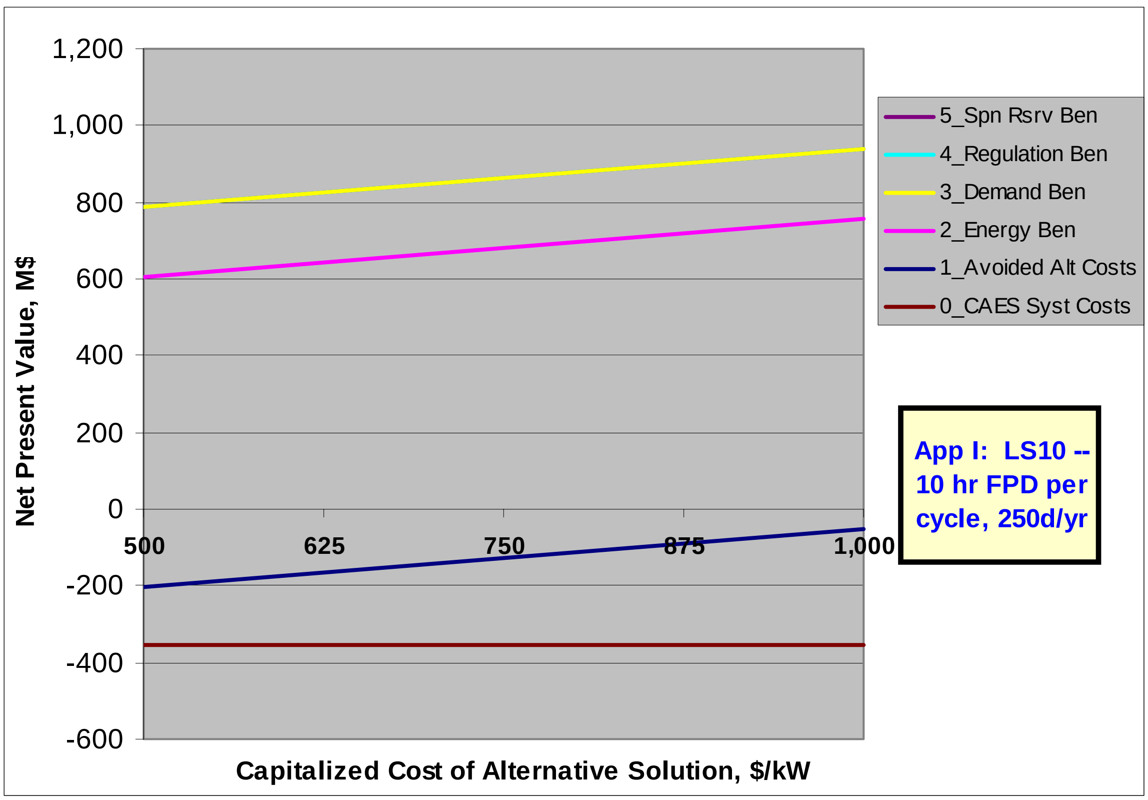

Figure 15-15
Application I: Large (300 MW_{ac}, 10 Hr Storage) CAES System NPV vs Cost of Alternative Solution

- Application C5: Combined Applications I, D, E (LS10 + RC + SR) – This application was evaluated on the assumption that an alternative to LS10 related upgrade costs can be obtained for net capitalized costs of about $750/kW, including acquisition, fixed and variable O&M, and property taxes and insurance costs. In addition, market rates for 10-hour load shifting, regulation control, and spinning reserve are included in the valuation. As shown in Table 15-15, this application yields a NPV of $953 million for an initial investment of about $135 million, corresponding to a total benefit to cost ratio of 3.6. As a measure of the sensitivity of NPV with respect to alternative solution costs, Figure 15-16 illustrates the change in NPV over a range of $500 to $1000/kW and shows that small CAES systems will compete favorably against alternative solutions over this range.

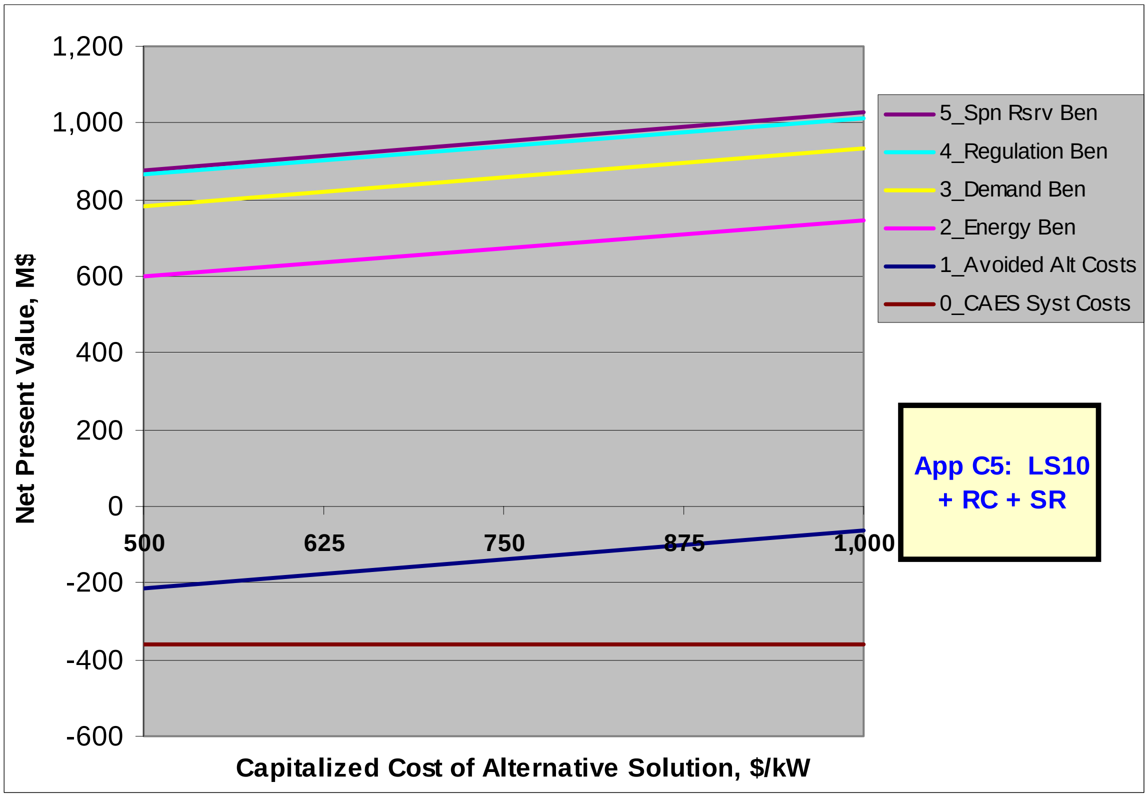

Figure 15-16
Application C5: Large (300 MW_{ac}, 10 Hr Storage) CAES System NPV vs Cost of Alternative Solution

Interpreting Results From Benefit-Cost Analyses

In general, CAES systems are expected to be very competitive for applications that benefit from several hours stored energy and do not require response times of less than a few minutes.

The reader is reminded that the foregoing analyses are intended as a guide to the initial consideration of energy storage options, and that these analyses are based on representative electric rates and costs for alternative solutions as described in Chapter 4. The assumptions used herein should be reviewed in light of project specific applications, alternative solutions, electric rates and financial parameters.

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