Guide to Estimating Benefits and Market Potential for Electricity Storage in New York (With Emphasis on New York City)

Final Report 07-06
March 2007

New York State
Energy Research and
Development Authority

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Final Report

Prepared for the

New York State Energy Research and Development Authority

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NOTICE

Abstract

Electricity storage holds great promise to make the New York power system more competitive, stable and secure. Storage allows for superior management of electricity supply and delivery cost and risk. Storage also enables other compelling electric resource options, including demand management and renewable energy. In addition, storage can increase fuel diversity, reduce overall fuel use and cost, and reduce air emissions.

Historically, electricity storage *has* been used to support and to optimize utility operations and services, and to add value to inexpensive energy. However, prospects for adding more electricity storage capacity like that used in the past – primarily large pumped hydroelectric storage – is limited, due mostly to siting, environmental, and licensing costs and challenges.

The features of state-of-the-art and emerging electricity storage technology combined with important institutional developments indicates an era of expanding opportunity for electricity storage as a cost-effective electric resource.

Most *emerging* electricity storage options are much more modular than pumped hydroelectric storage, though there is limited experience with those modular options for most electric utility applications. State-of-the-art modular electricity storage systems include a widening spectrum of advanced storage technologies coupled with increasingly sophisticated power conditioning, control, and communications subsystems.

Recent and emerging institutional developments that drive the opportunity for electricity storage include (in no specific order):

- regional peaking generation capacity constraints and/or high marginal energy and even capacity prices
- accelerating emphasis on load management to address on-peak capacity constraints, congestion, and high energy prices
- uncertainty and financial risk that limits investment in new transmission capacity, coupled with increasing congestion and energy losses in some transmission corridors
- increasing emphasis on a more robust grid that can withstand regional power disruptions and security threats
- increasing sophistication of transmission and distribution (T&D) monitoring, control, design, and utilization techniques
- increasing emphasis on locational marginal pricing (LMP), such as the use of locational based marginal prices (LBMPs) in New York
- states' adoption of the renewables portfolio standard (RPS), which is likely to increase use of renewable generation that has intermittent output

- increasing recognition of the benefits from distributed and modular energy resources (including electricity storage)
- increasing interest in superior utility asset utilization

This document describes a high level, technology-neutral framework for assessing potential financial benefits from and maximum market potential for electric energy storage. More specifically, it addresses electric utility-related applications, in New York, with an emphasis on New York City (NYC) – designated as Zone J by the New York Independent System Operator (NYISO).

Applications evaluated are summarized in Table ES.1.

Table ES.1. Storage Applications and Benefits Summary Descriptions

#	Application	Benefit	Description	Cost Element(s) or Price Signal(s)
1	Electric Energy Buy Low – Sell High	Revenue - VOC - (Purchase ÷ Efficiency)	1. Avoided market-based cost for purchases or 2. "Profit" from selling.	LBMP DAM
2	Electric Supply Capacity	Installed Capacity (ICAP)	Avoid charges/receive payment for "supply" installed capacity (ICAP).	NYISO ICAP Strip Auction
3	Reduce Transmission Capacity Requirements	Reduced Transmission Service Charges (TSCs)[2]	Avoid payment of charges incurred for access to the transmission system.	NYISO Transmission Service Charge (TSCs)
4	Reduce Transmission Congestion	Reduced Transmission Congestion Costs[2]	Reduce congestion on transmission system(s) -- to reduce congestion-related cost -- by serving peak load with storage.	LBMP DAM (Congestion Component)
5	Transmission and Distribution Upgrade Deferral	Avoided Annual Revenue Requirement for T&D Upgrade	Defer need for relatively expensive T&D upgrades by serving peak load downstream from hot spots.	Annual revenue requirement for upgrade.
6	Operating Reserve	Operating Reserve, Value	"Back-up" for Emergencies (loss of one or two large resources)	DAM Prices (LBMP and reserve capacity)
7	Regulation and Frequency Response (Regulation)	Regulation Service, Value	Maintain grid stability, frequency; attenuate small, frequent load fluctuations.	DAM Prices
8	Transmission Support	Enhanced Transmission Performance	Short duration support for transmission stability and improved throughput.	n/a
9	Electric Service Reliability	Reduced Outage Related Cost	Financial losses avoided due to improved PQ.	Value-of-Service as proxy
10	Electric Service PQ	Reduced PQ-related Cost	Financial losses avoided due to improved PQ.	Value-of-Service as proxy
11	Electric Service Bill Reduction: Demand Charges	Reduced Electric Service Bill[2]	Reduced electricity bill.	Tariff: PSC No. 9, Service Class 9, Rate I
12	Electric Service Bill Reduction: Time-of-use Energy Prices	Reduced Electric Service Bill[2]	Reduced electricity bill.	Tariff: PSC No. 9, Service Class 9, Rates II & III + Market Supply Charges
13	Renewable Electricity Production Time-shift	Enhanced Wind *Energy* Value	Increased benefit from wind energy if low value wind energy is sold when value is high.	DAM LBMP and "firmed capacity" (ICAP) Credit.
14	Renewables Capacity Firming	Enhanced Photovoltaics *Capacity* Value	Increase benefit from PV using low value grid energy to firm-up PV capacity on peak. Firming: from .5 to.95 effective capacity (Summer).	DAM LBMP and "firmed capacity" (ICAP) Credit.

Notes
1. Key Definitions: LBMP = Location Based Marginal Price (for energy). ICAP = Installed Capacity (electric supply). DAM = Day-ahead Market. VOC = non-energy-related variable operating cost (e.g., battery replacement).
2. A cost avoided by one entity may reduce revenue needed by another entity to cover fixed and/or embedded costs.

Application-specific maximum market potential and storage benefits are summarized in Table ES.2 (next page).

Three values are shown for each application:

1. **Maximum Market Potential**[1] for electricity storage is the maximum amount of storage capacity that could be used for the respective application.
2. **Unit Benefit** is the present worth of estimated benefits that accrue, over a ten year period, if electricity storage is used for the respective application. This value is expressed in units of dollars (present worth) per kW of storage installed (assuming 2.5% inflation, 10% discount rate, mid year convention).
3. **Total Benefit** that would accrue if the entire Maximum Market Potential is realized and if the estimated Unit Benefit ($/kW, present worth) accrues to all of that capacity.

It is important for readers to note the following: this document provides two important elements of the electricity storage story:

1) concepts and themes

2) quantitative estimates (e.g., of market potential and benefits).

By its nature, this document could not be based on the most current data, such as up-to-date demand projections and market prices.

In other cases, assumptions must be made to provide a general indication of important values when, in reality, such assumptions are quite circumstance-specific. For example, all present worth calculations assume a project life of 10 years, 2.5%/year inflation and 10% discount rate. For a given application the storage discharge duration required can vary significantly, so ranges are specified, and a point estimate is used for examples.

Nonetheless, the concepts/themes described herein will not change significantly, and the quantitative results presented should provide a helpful general indication of the merits of and potential for electricity storage use in New York.

Finally, for several reasons – including relatively high cost per kW of storage installed – it is important to identify superior value propositions for storage if storage is to be cost-effective for many situations. One important way to do that –

[1] Maximum market potential for a specific application includes opportunities for storage use a) to serve applications for which there is a competitive marketplace or b) on the margin, where additional or replacement capacity is needed (e.g., to serve load growth or for locations needing equipment replacement). It is the portion of total electric demand (*technical* market potential) for which storage could compete (on a benefit/cost basis) if it *is* cost-effective.

for any given location and circumstance – is to aggregate individual benefits for compatible applications.

Table ES.2. Estimated Market Potential and Benefits for Applications

#	Application	Maximum Market Potential MW, 10 Years*	Notes	Unit Benefit, $/kW, over 10 Years**	Total Benefit $ Million, over 10 Years**
1	Electric Energy Buy Low – Sell High	3,265	25% of Peak load[1] and of load growth[2] -- storage cannot compete with intermediate, baseload gen.	394	1,288
2	Electric Supply Capacity	3,739	ICAP required in 2006 -- 2,306 MW -- plus all load growth for next nine years. (Does not include reserve capacity or capacity provided via bilateral contracts.)	753	2,815
3	Reduce Transmission Capacity Requirements	3,759	Portion of in-city peak demand not served by in-city generation (20%) plus peak load growth. (Does not include reserves or capacity via bilateral contracts.)	93	350
4	Reduce Transmission Congestion	2,612	Portion of NYC peak demand not served by in-city generation (20%) plus growth[2] thereof. (Does not include reserves or capacity via bilateral contracts.)	72	187
5	Transmission and Distribution Upgrade Deferral	411	All T&D Upgrades: 1/30 of peak load each year (assume 30 year life); average 411 MW/year. Assume that storage can defer 10% of that amount, plus growth.	1,200[3]	494
6	Operating Reserve	445	Premise: generation is at least 2/3 of reserves. Storage: 1/3 of operating reserves (1/3 of 1,200 MW = 396 MW) plus growth[2] of that portion (49 MW).	258	115
7	Regulation and Frequency Response (Regulation)	281	Current market size for regulation (statewide) plus growth.[2]	789	351
8	Transmission Support	70	1/4 of existing market size for regulation (statewide) plus growth of that share.	169	47
9	Electric Service Reliability	842	1/4 of SC9 (tariff/customer class) load plus growth[2] of that load.	359	25
10	Electric Service PQ	337	10% of SC9 (tariff/customer class) load plus growth[2] of that load.	717	604
11	Electric Service Bill Reduction: Demand Charges	1,685	1/2 of SC9 (tariff/customer class) load plus growth[2] of that load.	1,076	362
12	Electric Service Bill Reduction: Time-of-use Energy Prices	270	8% of SC9 (tariff/customer class) load plus growth[2] of that load, for "peak clipping."	1,649	2,779
13	Renewable Electricity Production Time-shift	2,700	2,700 MW in Western upstate New York (per G.E./NYSERDA study).	832	2,246
14	Renewables Capacity Firming	188	1% of peak load (116 MW) and 5% of all load growth (72 MW).	323	61

* MW of cumulative market potential over ten years.
** $ present worth, over ten years, 2.5% inflation, 10% discount rate, mid year convention.
1 Peak Load in 2006 = 11,627 MW.
2 Peak load growth rate = 1.30%/year
3 Transportable storage could provide the same single year benefit at several locations.
Key premise: existing resources/equipment -- especially if it has useful life -- will not be replaced with storage.

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1. Introduction

1.a. Purpose

This document is designed to enable interested stakeholders to develop a high-level familiarity with the prospects for electricity storage in New York as a cost-effective electricity resource option. Specifically, this document: 1) provides guidance and generic values (assumptions) for use in calculating benefits associated with storage plants, 2) describes and illustrates the use of benefit cost ratios to evaluate financial viability of storage, and 3) provides guidance about making an initial estimate of economic market potential.

1.b. Scope

This document characterizes electric energy storage applications and related financial benefits, including a description of the means to estimate benefits. It also describes criteria and a framework for estimating market potential and provides maximum market potential estimations for New York Zone J (New York City, NYC).

Though much of the data used and the results shown in this report are specific to New York Zone J, it is possible to extrapolate the methodology to other regions, given the availability of the necessary data or even estimates thereof. Most data used in this document are included and/or described in the Appendices.

The intended audience for this document includes: 1) persons needing a framework for making a high-level estimate of benefits of energy storage (e.g. for policy or screening purposes), and 2) energy storage technology or project developers requiring high-level or “first cut” estimates of viable price points (based on benefits) and/or maximum market potential for their products.

Results presented herein are based on the most up-to-date information possible. However, benefit and market potential estimates presented are, by their nature, imprecise. First, the circumstances for any specific energy storage project can vary significantly from typical circumstances. Second, market conditions will change over time. For example, rules and regulations, benefit valuation methodologies, and supply and demand conditions *will* change. Nonetheless, the *approach* used is intended to provide a general indication of potential, and the approach is intended to be generally applicable even if other information or assumptions are used.

Notably, this report focuses on the *benefits* associated with use of energy storage *without regard to which technology* is used, and without regard to storage plant installed cost or operating cost (i.e., *without regard to storage cost-effectiveness*).

Indeed, the main purpose for this approach is to provide energy storage stakeholders with an indication of cost and characteristics required for storage to be cost-effective *and* cost-competitive.

For information about storage technologies' costs, readers could begin by consulting a report by Schoenung *et. al.*, *Long- versus Short-Term Energy Storage Technologies Analysis: A Life-Cycle Cost Study*, recently published by Sandia National Laboratories. [9]

1.c. Approach

When considering specific opportunities to develop energy storage products or services, it may be prudent to begin with a credible first-cut or high-level estimate of the prospective demand for, and financial benefit from, the product or service. This report documents such an evaluation for various utility-related energy storage applications.

As a way to generalize the evaluation, for each type of benefit considered, the authors provide an analytical approach that balances the need for precision with the cost to perform rigorous benefits assessments and market projections.

Given the interest in use of consistent bases, standard assumption values are provided for most of the important criteria used for benefit calculations and market estimates. However, almost certainly, other assumptions, and perhaps even other calculation methods, will be appropriate for specific circumstances.

The presentation in this document is technology neutral, though there is some coverage of technical requirements for storage systems used for specific applications. Other existing resources can be used to determine the cost for, and technical viability of, specific technologies [9] [11].

Most data and information and a significant portion of the analysis reflected in this document already existed. However, the combination of information and analysis herein *is* intended to be unique.

1.d. Introduction to the New York State and New York City Electricity Marketplace

1.d.1. Geographic

The New York state power system is comprised of eleven zones, some of which have subzones, as shown in the exploded diagram in Figure 1 below. Zones are designated as A through K. They reflect the location of major transmission corridors and interchanges that reflect utilities' service areas. Zone J is New York City; Consolidated Edison (Con Ed or Con Edison) is the utility for Zone J. New York has major interconnections with other regional power markets including the New England, the Pennsylvania-New Jersey-Maryland (PJM) areas to the South, Canada (Ontario) to the North, and Ohio to the West.

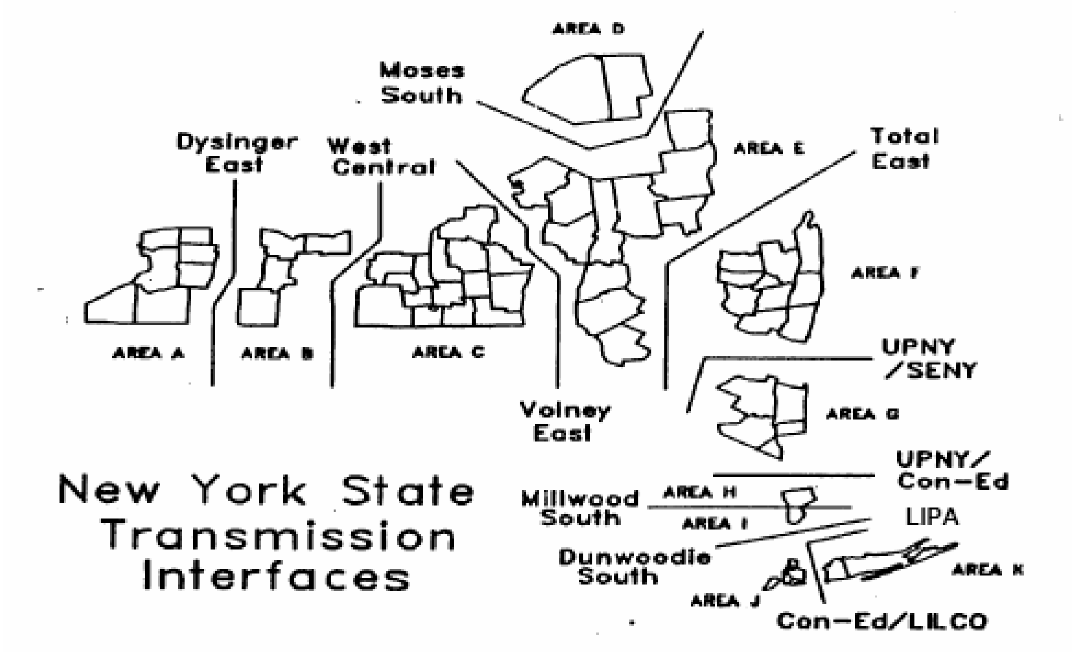


Figure 1. New York State Transmission System and NYISO Zones

1.d.2. Consolidated Edison

Consolidated Edison's (Con Ed's) 2005 Annual Report indicates that Con Ed has 3.2 million electric customers, 93,612 miles of underground distribution circuits – the largest such system in the world – and 36,047 miles of overhead distribution circuits. Total nameplate rating of their distribution equipment is 26,656 MVA. Further, Con Ed's natural gas system has more than 6,100 miles of gas distribution and transmission mains serving 1.1 million customers. The company's total 2005 sales were $11.67 Billion.

As of 2006, Con Ed's reported peak demand is about 14,500 MW, approximately 83% of which is in NYC. Peak demand has grown at about 1.5% per year in NYC and about 2.7% per year elsewhere. For the future; projected load growth of 1.3% per year is assumed.

Other notable circumstances for this report include:

- Per the Annual Report, by 2008 Con Edison "will invest more than $5.3 billion in its energy infrastructure," including "one of the most important parts of [its] long-term plan…construction of 14 new substations in the Con Edison service area.
- NYSERDA will help Con Edison accommodate a significant portion of peak demand growth over the next several years with newer, modular options, including distributed generation (DG), combined heat and power (CHP), and demand management (DM). [20]
- Con Edison owns virtually no electric generation.

- Con Edison provides commodity (electric energy) services for approximately 50 percent of the load in its service territory.
- There are nine retail suppliers that serve 200 Megawatts or more of load in the Con Edison service area.

1.d.3. NYISO

A key stakeholder in the New York power system (NYPS) is the independent system operator (ISO); the New York ISO (NYISO). The NYISO is accredited as New York's "Regional Transmission Organization" (RTO) pursuant to Standard Market Design (SMD) at the Federal Energy Regulatory Commission (FERC).

The NYISO facilitates a competitive marketplace and reliable, secure grid operation for the entire state. To do that, NYISO has several responsibilities such as market forecasts and capacity planning, facilitating transaction among market participants, coordinating and managing many grid operations, establishing standards and operating procedures for transmission owners and operators and for entities purchasing electricity and ancillary services.

See Appendix B for details.

1.d.4. Electricity Demand in New York

The following table summarizes projected loads in New York, from 2005 projected through 2015, as of 2005. Notably, the peak demand in NYC (Zone J) is about 11,400 MW. (Note that the actual peak demand in the New York Control Area in 2006 was 33,939 MW.)

Table 1. Regional Summer Peak Load Forecast (MW), Adjusted for Emergency Demand Response Program

Year	West	UHV	LHV	J	K	NYCA[1]
2005	8,798	2,045	4,577	11,247	5,162	31,690
2006	8,838	2,088	4,675	11,434	5,249	32,120
2007	8,881	2,091	4,803	11,589	5,339	32,560
2008	8,923	2,088	4,911	11,734	5,429	33,050
2009	8,963	2,096	5,041	11,891	5,506	33,480
2010	9,006	2,099	5,182	12,016	5,606	33,910
2011	9,046	2,101	5,336	12,141	5,703	34,280
2012	9,089	2,098	5,483	12,218	5,803	34,600
2013	9,132	2,107	5,711	12,350	5,905	34,880
2014	9,175	2,110	5,901	12,483	6,009	35,120
2015	9,208	2,118	6,084	12,572	6,036	35,370

West: NYCA - Zones A - E

UHV: Upper Hudson Valley - NYCA Zone F

LHV: Lower Hudson Valley - NYCA Zones G - I

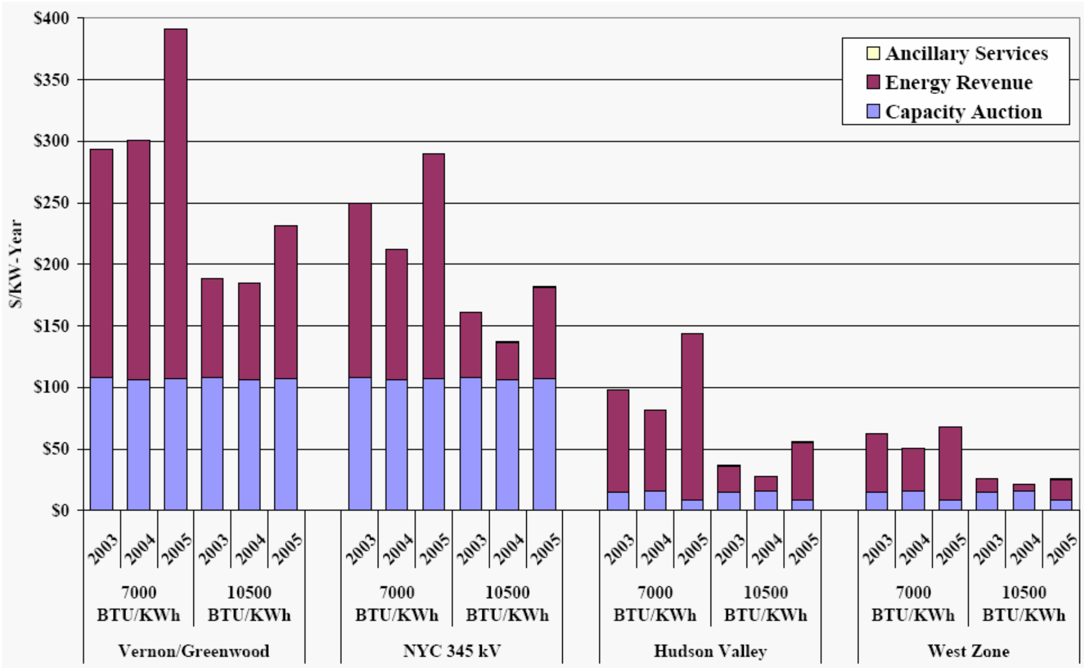
[1] Excludes 40 MW of station power that was included in 2004 forecast.

Special Note: Peaks are non-coincident. NYCA totals are rounded to the nearest ten megawatts.

Source: NYISO 2005 Load & Capacity Data

1.d.5. Electricity Cost in New York

Figure 2, below, provides a summary of electricity cost in New York during the years 2003 to 2005. Shown are the three primary elements of cost: 1) capacity, 2) energy, and 3) ancillary services. (Note that ancillary services are quite small and are barely noticeable in the figure).



Source: Potomac Economics, April 2006

Figure 2. Electricity Cost, 2003 – 2005, for Low and High Heat Rate Resources

1.e. The Emerging Market Opportunity for Electricity Storage in New York

Perhaps it should be no surprise that the electricity storage market opportunity in New York, especially NYC, is a rich one. If nothing else, many high-value loads and very important loads are served there.

Price signals in New York's electricity marketplace are also rich and are getting better. Importantly, effective price signals provide an expanding spectrum of prospective market participants with information needed to: a) assess the attractiveness of emerging value propositions for storage and for competing resource options, and b) participate in a competitive market for a growing number of "services."

New York's electricity marketplace offers several possible avenues into the market, such as: end user electricity bill reduction, wholesale energy and capacity markets, as qualified special case resources (SCRs), by third party energy services companies and aggregators and as an element of demand management and curtailable load/rate programs, including programs targeted at specific locations, to reduce and/or defer need for additional T&D infrastructure.

Market conditions in New York, especially NYC, also offer an increasing opportunity for storage to assist with grid congestion, grid electrical stability, grid security, increasing T&D energy losses, energy price volatility, generation capacity needs, distribution investment optimization, integrating renewables into the grid, reducing air pollution, etc.

Consider the following listing of *some* of the important circumstances in the New York electricity marketplace with implications for electricity storage.

Emphasis on In-city Resources

Due in part to heavy loading of transmission into NYC, there is a strong preference for developing in-city resources to serve peak demand growth. In fact, from 2005 to 2008 an estimated 675 MW of local demand (management) resources will be developed in Southeastern New York, mostly in NYC, to accommodate load growth. Of that amount, NYSERDA has responsibility for catalyzing development of 525 MW. There is a total of $435 Million committed to achieving the 675 MW total (about $645/kW).

The authors believe that interest in demand management and in-city resources provides an important market entry opportunity for electricity storage. The opportunity is enhanced by at least three important considerations.

First, though demand response and efficiency are important elements of the approach, reducing loads (by demand management or energy efficiency) has limits. In-city and/or on-site energy storage can serve load and reduce demand on the grid.

Second, as air emission standards are tightened, restrictions on use of Diesel engine-driven emergency generators are likely to increase, reducing the viability of that existing and important option as a source of in-city supply capacity.

Finally, Consolidated Edison will receive $22.50 of incentive per kW of end-user demand reduction. Though modest, the payment reflects an important development: Historically, utilities had a financial *disincentive* to encourage conservation, demand management, and end-user-owned resources (especially generation). [24]

Increasing Emphasis on Resource Aggregation

An important element of the market opportunity is the emerging role of resource aggregation organizations. These entities aggregate blocks of demand response and/or generation resources, so that diverse and distributed resources can be dispatched in a coordinated fashion.

Consider these words from David Lawrence, Manager of Market Strategy at the NYISO, spoken at a pivotal technical conference addressing Demand Response (January 25, 2006) at the Federal Energy Regulatory Commission (FERC): "The growth of aggregation organizations offering demand response services indicates that demand response can be a viable business model in New York." According to Mr. Lawrence, roughly half of the capacity deployed under auspices of

NYISO's Special Case Resource (SCR) program is currently registered with aggregation organizations. [25]

(On-site and modular in-city storage is likely to be regarded as a special case resource by the NYISO.)

T&D Congestion

New York already has congestion pricing between regions of the state (zones). The NYISO is moving to a system that prices congestion-related effects in nine "load pocket interface constraints" within NYC (Zone J). Such locational congestion pricing is possible, in part, by increasingly detailed transmission constraint modeling. [23]

T&D Deferral

In April 2006, Consolidated Edison issued a Request for Proposals (RFP) for multi-year deferrals for targeted T&D. The RFP calls for 150 MW of distributed generation and energy efficiency, though storage is not excluded. The RFP is an important indication that the market for T&D deferral is developing. [24]

Electricity storage could be used as the primary power source for T&D deferral, storage systems could provide some of the capacity, or storage could be a component/subsystem of other systems that integrate generation and load management.

High Wholesale Electric Supply Costs

Given several important circumstances, including the high cost to develop in-city generation and increasing transmission constraints (especially into NYC), electric supply *capacity* has high and increasing value. Those conditions, plus performance of the aging fleet of in-city generation and others, contributed to high electric *energy* prices as well.

Evolving Retail Electricity Pricing

As time-of-use (and locational) pricing evolve, end users should expect increasing price differentiation for energy, capacity, and other elements of service such as ancillary services, based on location, time-of-day, season, and possibly even service reliability and quality. The market opportunity is enhanced to the extent that increased electricity price differentiation allows electricity end users to internalize additional benefits from storage.

Renewables

New York and the United States as a whole are moving toward the increased use of renewable energy. Some renewables, primarily wind generation, but including solar power, are "intermittent," and thus have diminished value relative to generation that can be controlled or that can provide constant output. Electricity storage could play an important role in catalyzing the increased use of renewables by: 1) "firming up" renewable generation *capacity* (making output more constant), and 2) “time-shifting” *energy* from renewable energy, so energy produced when value is low may be used or sold when demand and price are high.

Reducing Carbon Emissions

Increasing focus on carbon dioxide indicates an important opportunity for electric energy storage to reduce carbon emissions. Indeed, the Electric Power Research Institute (EPRI) identifies distributed electricity storage as one type of distributed energy resource (DER) that could be an element of a comprehensive approach to reducing carbon emissions.[26]

Storage can assist in several ways, including: 1) enabling more constant operation of generation plants at more optimal (i.e., efficient, cleaner) output levels, 2) enable use of additional energy from hydroelectric and wind generation, especially during “off-peak” periods, 3) electricity storage provides reserve capacity that is in some respects superior to generation-based reserves, *and* storage provides reserves without real-time emissions from “part load” operation required of generation-based reserve capacity, and 4) electricity storage may allow for reduced use of less efficient peaking generation resources (with relatively high emissions per kWh).

Independent System Operators’ Evolving Interest in Electricity Storage

The New England Independent System Operator (ISO-NE) includes electricity storage in its list of technologies that may serve as Other Demand Resources (ODRs). ODRs will be eligible to receive capacity payments under terms of ISO-NE’s transition to a more competitive electricity marketplace in 2010 and will be allowed to participate in Forward Capacity Auctions to begin in 2008 for capacity delivered after the 2010 transition.

Important Electricity Storage Technology Drivers

Though interest in storage for stationary applications is increasing, other important drivers affect storage technology more significantly. Interest in hybrid vehicles, and to lesser extent electric vehicles, seems likely to have a significant impact on energy storage technology itself and on electricity storage subsystems such as power electronics, charging control, power and energy management, etc. Growing interest in distributed generation and demand management is driving technical developments affecting distributed energy resources (DERs) monitoring and control needed for aggregation and for efficacious electricity storage operation for “grid-related” applications. Technical improvement of smaller storage systems (< 2 kW) and their subsystems is driven by ongoing adoption of state-of-the-art storage technology by participants in the traditional uninterruptible power supply (UPS) industry.

2. Electric Energy Storage Applications

This section is an introduction to the fourteen utility-related uses (applications) for electricity storage that are addressed in this report.

Readers are encouraged to note the important distinction made in this report between *applications* and *benefits*. *Applications* (listed below) are individual purposes for which storage is used. *Benefits* involve *financial* gain. Benefits accrue because storage is used to: a) generate revenues (revenue production), and/or b) reduce cost (cost reduction) or avoid costs (avoided costs).

Furthermore, storage used for one specific *application* may provide one or more additional benefits. Given the relatively high cost for energy storage, it is important for energy storage advocates to know about and to be adept at combining those benefits. That is important because it increases the overall value of a given storage system, so that the system has a better chance of being cost-effective.

Consider an example: A utility customer stores low priced energy during off-peak periods for discharge when high on-peak prices prevail. The primary or intended benefit is electric energy cost reduction. Depending on circumstances, the energy storage plant could provide other benefits such as: reduced demand charges, reduced financial losses and/or damage due to poor power quality, and improved response to (reduced financial losses due to) power outages.

Under certain conditions, revenue production is possible (e.g., for supply capacity revenue) if storage owners have permission to participate in demand reduction programs such as those sponsored by wholesale institutions including Energy Services Companies (ESCOs), Load Serving Entities (LSEs), Energy Efficiency Providers (EEPs), Demand Response Providers (DRPs), and Curtailment Service Providers (CSPs).

2.a. Applications List

Applications are grouped into four categories:

- Grid Capacity and Energy
- Ancillary Services
- End-user/Third Party/ESCO
- Renewables
-

The fourteen applications (grouped by category) are:

<u>Grid Capacity and Energy</u>

1. Electric Energy Buy Low – Sell High (buy low – sell high)
2. Electric Supply Capacity (ICAP)
3. Reduce Transmission Capacity Requirements
4. Reduce Transmission Congestion

5. Transmission and Distribution Upgrade Deferral (T&D deferral)

Ancillary Services

6. Operating Reserves
7. Regulation and Frequency Response (regulation)
8. Transmission Support

End-user/Third Party

9. Electric Service Reliability (reliability)
10. Electric Service Power Quality (PQ)
11. Electric Service Bill Reduction: Demand Charges
12. Electric Service Bill Reduction: Time-of-use Energy Pricing

Renewables

13. Renewables Electricity Production Time-shift
14. Renewables Capacity Firming (renewables capacity)

Applications and related benefits are described in Table 2, below.

2.b. Storage System Primary Technical Considerations for Applications

2.b.1. Storage System Sizing

Energy versus Power

Electricity storage systems have two key design parameters that must be specified before undertaking any meaningful discussion about how storage could be used. Those two criteria are: 1) energy and 2) power. Energy relates to the *amount* of energy that can be stored and then discharged from the storage system when it is fully charged. Power relates to the *rate* at which that energy can be discharged.

Discharge Duration

The storage system's discharge duration is the amount of time that a system can discharge, at its rated power output, when fully charged. Storage systems are usually described either as having 1) a given energy (storage) and the nominal power rating or 2) a given discharge duration at the nominal power rating. For example, a storage system whose power rating is two MW and that can store six MWh of energy could also be described as being a two MW plant with a three hour discharge duration (6 MWh ÷ 2MW).

Generally, two or more hours of discharge duration is needed for most electricity service related applications; though for a few applications, a discharge duration of seconds to minutes provides significant benefits. Application-specific assumptions for discharge duration are provided in respective report sections that follow and are summarized in Table 2.

Table 2. Storage Applications and Benefits Summary Descriptions

#	Application	Benefit	Description	Cost Element(s) or Price Signal(s)
1	Electric Energy Buy Low – Sell High	Revenue - VOC - (Purchase ÷ Efficiency)	1. Avoided market-based cost for purchases or 2. "Profit" from selling.	LBMP DAM
2	Electric Supply Capacity	Installed Capacity (ICAP)	Avoid charges/receive payment for "supply" installed capacity (ICAP).	NYISO ICAP Strip Auction
3	Reduce Transmission Capacity Requirements	Reduced Transmission Service Charges (TSCs)[2]	Avoid payment of charges incurred for access to the transmission system.	NYISO Transmission Service Charge (TSCs)
4	Reduce Transmission Congestion	Reduced Transmission Congestion Costs[2]	Reduce congestion on transmission system(s) -- to reduce congestion-related cost -- by serving peak load with storage.	LBMP DAM (Congestion Component)
5	Transmission and Distribution Upgrade Deferral	Avoided Annual Revenue Requirement for T&D Upgrade	Defer need for relatively expensive T&D upgrades by serving peak load downstream from hot spots.	Annual revenue requirement for upgrade.
6	Operating Reserve	Operating Reserve, Value	"Back-up" for Emergencies (loss of one or two large resources)	DAM Prices (LBMP and reserve capacity)
7	Regulation and Frequency Response (Regulation)	Regulation Service, Value	Maintain grid stability, frequency; attenuate small, frequent load fluctuations.	DAM Prices
8	Transmission Support	Enhanced Transmission Performance	Short duration support for transmission stability and improved throughput.	n/a
9	Electric Service Reliability	Reduced Outage Related Cost	Financial losses avoided due to improved PQ.	Value-of-Service as proxy
10	Electric Service PQ	Reduced PQ-related Cost	Financial losses avoided due to improved PQ.	Value-of-Service as proxy
11	Electric Service Bill Reduction: Demand Charges	Reduced Electric Service Bill[2]	Reduced electricity bill.	Tariff: PSC No. 9, Service Class 9, Rate I
12	Electric Service Bill Reduction: Time-of-use Energy Prices	Reduced Electric Service Bill[2]	Reduced electricity bill.	Tariff: PSC No. 9, Service Class 9, Rates II & III + Market Supply Charges
13	Renewable Electricity Production Time-shift	Enhanced Wind *Energy* Value	Increased benefit from wind energy if low value wind energy is sold when value is high.	DAM LBMP and "firmed capacity" (ICAP) Credit.
14	Renewables Capacity Firming	Enhanced Photovoltaics *Capacity* Value	Increase benefit from PV using low value grid energy to firm-up PV capacity on peak. Firming: from .5 to.95 effective capacity (Summer).	DAM LBMP and "firmed capacity" (ICAP) Credit.

Notes
1. Key Definitions: LBMP = Location Based Marginal Price (for energy). ICAP = Installed Capacity (electric supply). DAM = Day-ahead Market. VOC = non-energy-related variable operating cost (e.g., battery replacement).
2. A cost avoided by one entity may reduce revenue needed by another entity to cover fixed and/or embedded costs.

Power Rating

Storage power rating is the rate at which a storage system can deliver energy. Units used in this report are kiloWatts (kW) and MegaWatts (MW). A storage system’s power rating is very circumstance-specific, ranging from a few kiloWatts for systems serving small/specific loads to multi-MegaWatt systems serving large/aggregated loads.

Nominal versus "Emergency" Power Rating

Some energy storage technologies can discharge at a relatively high rate for relatively short periods of time (often referred to as "emergency" rating). For this document, the discharge rate used is what would commonly be referred to as design rating or nominal rating: the rate at which energy is normally discharged. In this report, the power rating specified is the nominal rating and no attempt is made to address the possible benefit from the emergency power rating feature.

Sizing Guide

For more detailed coverage of storage sizing, readers could refer to a report developed by Sandia National Laboratories entitled *Estimating Electricity Storage Power Rating and Discharge Duration for Utility Transmission and Distribution Deferral, a Study for the DOE Energy Storage Program*. [15]

2.b.2. Storage Variable Operating Cost

All storage options have some variable operating cost (VOC) associated with each charge - discharge cycle. To be clear, that cost is not related to the cost to purchase electric energy for charging. Most of the cost is for wear and tear or degradation of equipment, electrochemical batteries being the most expensive. In this report, the VOC is expressed in units of ¢/kWh *out* (discharged from storage).

VOC values range from a few tenths of a cent per kWh for pumped hydroelectric to several cents per kWh for electrochemical batteries that do not tolerate "deep discharging" well.

2.b.3. Storage System Scale

Any given application may be best served by a storage plant with a given scale. For example, traditionally "bulk" energy storage used to augment an electric supply system has a power rating ranging from tens of MW to hundreds of MW. At the other end of the spectrum is under-desk uninterruptible power supplies (UPSs), used to keep computers from shutting down when electric service is interrupted or when power quality is poor.

Similarly, some storage types scale-up better than others, so there may be a limited number of storage types that serve large or small applications cost-effectively. For large scale storage, pumped hydroelectric and possibly compressed air energy storage (CAES) are leading options. Clearly, under-desk pumped hydroelectric energy storage is impractical, though modular, battery-based systems with modern power electronics are well suited to under-desk applications.

2.b.4. Storage System Reliability

Like power rating and discharge duration, storage system reliability requirements are circumstance-specific. Little general guidance is possible. The project design engineer is responsible for designing a plant that provides enough power and is as reliable as necessary to serve the respective application.

There is one other important reliability-related consideration for electricity service applications that obviates the need for "very reliable" systems: many leading electricity storage technologies are inherently modular. So, storage systems for electric service applications may be comprised of multiple "modules" such that it is unlikely that more than a few will fail at the same time; thus most of the capacity will be available most of the time.

2.b.5. Storage System Ramp or Response Rate

For some applications, the rate at which storage can "ramp" (change its rate of output) is important. These include applications that stabilize the electric system or that must come on line quickly. For some applications, especially "electric energy buy low – sell high," the ramp rate is less important. In general, this characteristic of energy storage is only given cursory coverage.

2.b.6. Storage System Footprint and Space Requirements

This report does not address footprint or space requirements for energy storage. However, depending on the storage technology, space constraints may indeed be a challenge, especially in heavily urbanized areas, and especially NYC.

2.b.7. Power Versus Energy Technologies for Applications

Though this report does not focus on specific storage technologies, it is helpful to understand the distinction between storage systems characterized as those for a) power applications, and those best suited to b) energy applications. Storage technologies that are well suited to high power output (usually for relatively short periods of time; seconds to a few minutes) are informally categorized by the storage community as "power technologies" and those best suited to storing large amounts of energy (for discharge durations of many minutes to hours) as "energy technologies."

Figure 3, below, shows the relationship between: a) applications and b) storage power and discharge duration. Applications that are best served by power technologies are shown toward the bottom of the figure, and applications best served by energy technologies appear at the top of the figure.

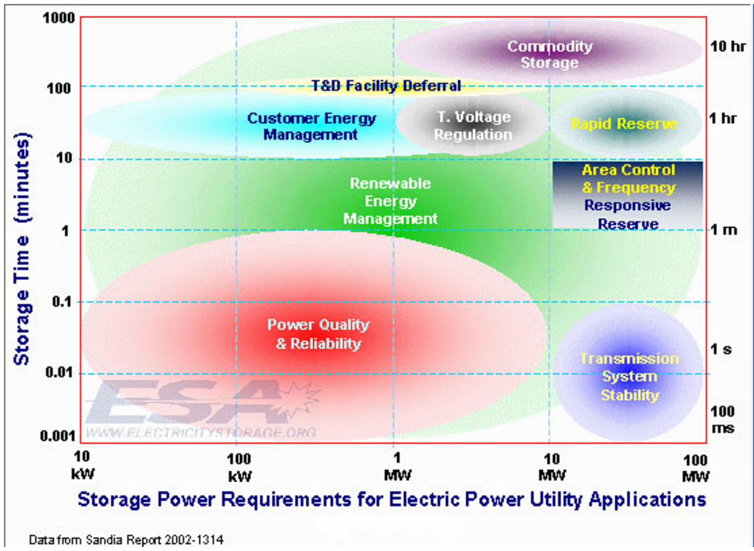


Figure 3. Storage Discharge Duration and Power Requirements for Applications

2.b.8. True, Apparent, and Reactive Power

For this report, units of true power (kiloWatts or megaWatts) are used universally when apparent power—measured in units of kiloVolt-Amps (kVA) or MegaVolt-Amps (MVA) may be the most technically correct units. However, given the limited precision possible for the market and benefit estimations, the distinction between these units has limited impact on results.

2.c. Grid Capacity and Energy Applications

Application #1 Electric Energy Buy Low – Sell High

Application Overview

Electric energy buy low – sell high (buy low – sell high) involves: 1) purchase of relatively inexpensive electric energy that is usually available during periods when demand for electricity is low, to 2) charge an electricity storage plant, so that 3) the low-priced energy can be used or sold when the price for electricity is high.

(Note: In this context, sales are mostly or entirely to end-users, though sales could be made to other entities via the wholesale/commodity electricity marketplace.)

In New York, buy low and sell high transactions are valued using market prices that are, for the most part, linked to “locational based marginal price” (LBMP). LBMPs are time and area (zone) specific electricity prices that include: 1) the price for electric energy, 2) transmission energy losses, and 3) transmission congestion, if any. LBMPs are described in detail in Appendix D.

Notable Technical Considerations

For the buy low – sell high application, the optimal storage discharge duration is determined based on the incremental value of being able to discharge for a longer period of time. That is, the cost for increasing the discharge duration (incremental cost) must be commensurate with the added benefit (incremental benefit).

The range of possible discharge durations for the buy low – sell high application is two hours to as many as eight hours, depending on circumstances in a given energy marketplace. The buy low – sell high benefit for discharge durations ranging from two hours to eight hours are presented in Section 4.

Application Synergies

Although each case is unique, if the plant used for this application is in the right location and if the plant is discharged at the right times, it could also serve the following applications: T&D deferral, reduce transmission congestion, reliability, PQ, or ancillary services.

Application #2 Electric Supply Capacity

Application Overview

New York has a diverse electric supply system with over 90% of capacity being owned by independent entities, either wholesale generation companies or demand management resource providers and aggregators.

A growing portion of the electric supply capacity – installed capacity (ICAP) – is traded in the ICAP market. Much is sold in bi-lateral contracts to load serving entities (LSEs), including the electric utilities that still provide electric capacity and commodity electric energy to most customers of their distribution (electricity delivery) service. The balance of capacity needs is subject to NYISO ICAP auctions twice per year and, if needed to make up for ICAP shortfalls, monthly.

De-rated for forced outages, ICAP is sold as “unforced capacity” or UCAP.

In load pockets such as New York City and Long Island (and in regions near to New York such as Southwest Connecticut, and the Boston area), a portion of generation must be local. Generation or storage that is located close to loads or demand management (DM) resources that reduce load in the load pocket often have a premium value.

See Appendix C for other details.

As of 2006, Special Case Resources (SCR) – the electric supply category into which storage would most logically fit – account for approximately 2.25% of the capacity needed by LSEs in New York (in 2006 there were 261 MW of SCRs and load of 11,628 MW).

Under terms of Rider P to Con Edison's electricity tariffs, ICAP produced on-site by a generator can be sold to Con Edison in increments of 100 kW, when the NYISO Special Case Resource programs are called. This program is administered on behalf of the New York Power Authority (NYPA), the New York City Public Utility Service (NYCPUS), or the County of Westchester Public Utility Service Agency (COWPUSA). Electric supply capacity purchase price for summer 2006 is $12.35 per kilowatt per month (of generation or load reduction) in New York City and $1.44 in Westchester County. [22]

Similar capacity-providing measures are allowed in other wholesale markets with locational marginal pricing for energy, such as Pennsylvania Jersey Maryland Interconnect (PJM) and ISO-New England.

Also, Con Edison offers service under terms of a conventional curtailable tariff, per Rider O (see the Con Edison web site) that allows for curtailable loads in blocks (including aggregation) of at least 50 kW. Loads must be curtailable for no less than four hours and will be curtailed for no more than eight hours, on weekdays between 8:00 AM and midnight during the Summer Billing Period.

Notable Technical Considerations

It is challenging to make generalizations about storage discharge duration for this application because the annual hours of operation, frequency of operation, and duration of operation are specific to each electricity marketplace.

A key criterion affecting discharge duration for this application is the way that generation capacity is priced. For example, if capacity is priced on a per hour basis, then storage plant duration is flexible. If prices require that the capacity resource be available for a specified duration for each occurrence or require operation during an entire time period (e.g., 1:00 pm – 6:00 pm, five hours), then the storage plant discharge duration must accommodate those requirements.

Application Synergies

Depending on location and other circumstances, storage used for this application may be compatible with the following applications: T&D deferral, transmission support, reliability, PQ, and capacity reserves.

Application #3 Reduce Transmission Capacity Requirements

Application Overview

In this application, storage is used to reduce the load on the transmission system such that the freed-up capacity can be used to generate additional benefit. For example, the additional capacity could be used to transfer additional energy for sale, or the capacity could be "rented" by another entity that needs to transfer electricity.

To reduce transmission capacity requirements using storage, low-priced off-peak electric energy is stored locally and then discharged locally during peak demand periods, when the transmission system is fully loaded. An example is storing unused electricity produced by a residential Micro-CHP for later use by the residence or for sale to the grid. Not only would transmission charges be reduced, distribution charges might also be reduced.

In some regions, “postage stamp” transmission access charges are used. In those cases, transmission prices are the same during all hours of the year. In other regions, time-specific access charges may apply. Prices may be applied hourly, daily, or monthly.

In New York, market-based energy transfers across a transmission owner’s (TO’s) transmission system is subject to a “transmission service charge” (TSC). TSCs cover the TO’s cost to own the transmission equipment (annual revenue requirement). (See Appendix G for more details.)

Given the way transmission is priced in New York – $/MWh transferred, without time differentiation – use of storage could *increase* transmission cost (given storage losses). Typically 20% to 30% of each kWh used to charge storage is lost before the energy is extracted. So, if all charging energy for storage is transmitted, then transmission charges would apply to 120% to 130% of the energy ultimately delivered to the end user.

If, instead, *charging* energy comes from local sources (i.e. it is not transmitted), and storage output obviates the need to transmit energy on-peak, then transmission service charges are avoided.

In NYC, charging energy is assumed to come from in-city generation and is assumed to offset some of the 20% of energy “imported” into the zone (NYC).

Notable Technical Considerations

Discharge duration needed for this application is driven by the prevailing market conditions and the way that transmission access is priced. Furthermore, given the relatively small magnitude of the transmission capacity benefit, it is not likely to be a key decision criterion. Instead, it is likely to be an important incidental for storage deployed for another reason.

Application Synergies

Storage used for this application could be compatible with the buy low – sell high application and, depending on location and other circumstances, it could also be used for the T&D deferral application, the customer reliability and PQ applications, and the ancillary services and transmission support applications.

Readers should note that this application has a significant overlap with the reduce transmission congestion application and the transmission upgrade deferral application.

Application #4 Reduce Transmission Congestion

Application Overview

In many areas, transmission capacity additions are not keeping pace with the growth in peak electric demand, so transmission systems are becoming congested during periods of peak demand as demand for transmission capacity exceeds supply. This situation drives an increased use of congestion charges – fees that reflect higher costs that occur when congestion occurs.

Storage could be used to reduce congestion (and to avoid congestion-related charges). To do this, low priced off-peak energy is stored and then discharged, later, when congestion occurs. That reduces use of the transmission system when congestion is (or would otherwise be) occurring.

Notable Technical Considerations

Storage discharge duration needed for transmission congestion relief cannot be generalized easily, given all the possible circumstances. It may be that there are just a few individual hours throughout the year when congestion exists, or there may be a few occurrences during a year when there are several consecutive hours of transmission congestion. Congestion may occur during hundreds or perhaps even thousands of hours per year. Finally, congestion may vary from year-to-year because supply and demand are always changing.

The benefit associated with this application is relatively small; it will probably be an incidental benefit that accrues when storage is used for another, more beneficial application. So, storage discharge duration will be determined by considerations related to other applications. The *minimum* discharge duration assumed is two hours.

Application Synergies

Storage systems used for this application may be compatible with the buy low – sell high application. If it is located in the right place, the storage could possibly be used for the T&D deferral, reliability, PQ, transmission support, and ancillary services applications.

Readers should note that this application has a significant overlap with the reduce transmission capacity requirements application.

Application #5 Transmission and Distribution Upgrade Deferral

Application Overview

Transmission and distribution (T&D) upgrade deferral involves delaying utility investments in transmission and/or distribution system upgrades by using relatively small amounts of storage (power).

Consider a part of the utility distribution system whose peak electric loading is approaching the equipment's load carrying capacity (design rating). In some cases, a small amount of energy storage can serve enough load – downstream from the overloaded equipment (a.k.a. hot spot) – so that the utility may defer the need for to upgrade the equipment.

As a specific example, a 15 MW transformer is operating at 3% below its rating. Load growth is about 2%/year. Engineers plan to upgrade the transformer and exit circuits next year by adding 5 MVA of additional capacity.

As an alternative, engineers could consider installing enough storage to meet the expected load growth for next year, plus any appropriate engineering contingency (it is probably not prudent to install "just enough" storage when facing load growth uncertainty).

Assuming a 2% annual load growth rate, during the next year load growth is about 300 kW (2% * 15 MW existing transformer rating).

For illustration, adding a 25% engineering contingency means that the storage plant would have to be about 375 kW. In this example, assume that the engineers determine three hours to be sufficient discharge duration.

The key concept is that a small amount of storage – 300 kW in the example – can be used to delay a large "lump" investment in T&D equipment (e.g. 5 MW in the example).

Among other effects, this approach: 1) reduces overall cost to ratepayers, 2) increases utility asset utilization, 3) allows use of the capital for another important project, and 4) reduces financial risk associated with large lump investments whose capacity may never be used.

As described in Appendix G, in New York the electricity marketplace plays an important role in establishing the value of transmission. If the value were to be deemed great enough, then merchant transmission upgrades may be drawn out. One example is a cross-Long Island Sound transmission line from Connecticut and the New England grid to Long Island. Distribution deferral is recognized as a major component of demand resource programs, and indeed, in 2006 Consolidated Edison has solicited bids for the use of energy efficiency and distributed generation to defer from 120 to 150 MW equivalent of distribution upgrades in a number of targeted distribution networks.

Details about the T&D deferral benefit estimate are provided in Section 4.

Notable Technical Considerations

With regard to the T&D deferral benefit, the term transmission actually refers to what is commonly called subtransmission. Subtransmission has Voltages and load carrying capacities that are a) somewhat less than ratings for ”high Voltage” regional transmission and b) somewhat more than ratings for specific distribution systems.

Storage power rating and discharge duration are both critical design criteria for the T&D deferral application. In short, to state the obvious, the energy storage must serve sufficient load, for as long as needed, to keep loading on the T&D equipment at or below the specified maximum.

For most circuits, the highest loads occur on just a few days per year, for just a few hours per year. In some cases, the highest annual load occurs on one specific day whose peak is somewhat higher than any other day.

The assumed minimum discharge duration for this application is two hours, and the maximum is eight hours.

With regard to electric supply capacity value, coincidence with *supply* system peak has always been paramount. In the future, it seems likely that more emphasis will be focused on establishing zone-specific and even T&D-node-specific capacity value.

Application Synergies

Depending on location and other circumstances, a plant used for this application could also serve the buy low - sell high application and possibly for transmission congestion reduction, reliability, PQ, and/or ancillary services.

2.d. Ancillary Services

<u>Introduction to Ancillary Services</u>

Ancillary services are defined by the Federal Energy Regulatory Commission (FERC) as those services necessary to support the delivery of electricity from seller to purchaser while maintaining the integrity and reliability of the interconnected transmission system (“the network”).

In New York, the New York Independent System Operator (NYISO) administers the ancillary services market. There are five ancillary services in New York; two are evaluated as applications in this report – frequency regulation and reserves. The five ancillary services are listed in Table 3.

Table 3. List of Ancillary Services in New York

1. Scheduling, System Control & Dispatch Service	Scheduling generation and transactions ahead of time, and controlling some generation in real time to maintain generation/load balance.
2. Voltage Support Service	The generation or absorption of reactive power to maintain transmission system voltages within required ranges.
3. Regulation and Frequency Response Service*	Minute-by-minute generation/load balance within a control area to meet NERC standards.
4. Operating Reserve Service*	Generation capacity that is on-line but unloaded and that can respond within 10 minutes to compensate for generation or transmission outages. "Frequency-responsive" spinning reserve responds within 10 seconds to maintain system frequency. Also includes generation capacity that may be off-line or curtailable load that can respond within 10 minutes to compensate for generation or transmission outages.
5. Black Start	Ability to energize part of a grid without outside assistance after a blackout occurs.

Definitions are from the Federal Energy Regulatory Commission (FERC)
*Evaluated for this report.

Technical Considerations

In general, resources used to provide ancillary services must be reliable and must be capable of rapid start-up, ramping, and transition to/from charging and discharging modes. They must also have high quality stable output.

Storage used to provide some ancillary services may also be used for other applications including buy low-sell high, PQ, and reliability.

Note that voltage support for the electric supply system was not designated as a storage benefit for this report, primarily because the magnitude of the benefit (based on the price paid by the NYISO for the foreseeable future) is quite low compared to the cost for storage – less than $4/kW-year.

However, authors do believe that storage – combined with power conditioning subsystems that are capable of providing reactive power – could provide high-value localized Voltage support, especially during times when the grid is heavily loaded and/or during region-wide grid contingencies. Some coverage of that topic is provided in Appendix E.

Application #6 Operating Reserves

Application Overview

This service (operating reserves or reserves) is, in essence, backup generation for the grid. It is needed after a major area-wide or region-wide power system disruption, especially loss of a major power plant or transmission corridor. The NYISO offers this service to transmission owner/operators (TOs). TOs may purchase the service from the NYISO or may provide their own operating reserves.

The existing pricing system for reserve capacity reflects a system whose real-time electricity demand is supplied entirely or almost entirely by generation (rather than storage or demand management). Notably most generation-based reserves respond slowly, ramping up over several or many minutes. Specifically, power from operating reserve resources must be available to the NYISO within 30 minutes, maximum. Two-thirds of that capacity must be available within 10 minutes.

There is increasing general interest in alternatives to generation for reserve capacity, especially "demand response," which entails reduction of demand when and where needed, in lieu of using additional *generation* capacity. The interest is driven by many factors, including the possibility that alternatives could make the electric system less vulnerable to regional power emergencies.

One way that demand response and distributed electricity storage could improve the grid is by providing "rapid response" reserve capacity used to optimize generation-based reserves. Unfortunately, generation-centric pricing for capacity reserves does not allow for a premium for this "rapid response" feature, should such a premium be identified.

Theoretically, storage capacity may contribute reserve capacity without discharging (i.e., the storage is standing by, ready to provide reserves if needed), and the storage can provide twice its capacity as reserves when it is charging (if charging is stopped and discharging commences).

Notable Technical Considerations

Perhaps it goes without saying, but reliability is important for this application.

Application Synergies

Depending on the location, storage used for reserves could be used for other applications, especially localized voltage support (reactive power) and local reliability and PQ.

(Actually, it is more likely that storage used for other higher value applications could also be used, some of the time, to provide reserves.)

Application #7 Regulation and Frequency Response

Application Overview

The regulation and frequency response (regulation) service is used to fine-tune the real-time balance between supply resources and customer demand, consistent with NERC requirements. The NYISO controls operation of resources that provide the regulation – usually generation. The NYISO offers this service to transmission owners/operators who may purchase that service or may make arrangements for comparable service.

Storage used for regulation constantly adjusts its rate of discharge and/or charge to accommodate "requests" for "up" or for "down" regulation. The two types of regulation are provided as follows:

- Up regulation – increase discharge rate or reduce charge rate; has effect like ramping up generation (increasing generation output).
- Down regulation – decrease discharge rate or increase charge rate; has effect like ramping down generation (decreasing generation output).

Energy "absorbed" when providing down regulation is "purchased" at the prevailing energy price. However, in many cases, that same energy may be discharged (when providing up regulation) within a few minutes to an hour, so the discharged energy is worth about the same as the charging energy cost. The net cost for energy is, roughly, the cost associated with energy storage losses.

Notable Technical Considerations

Assuming that storage has necessary electrical characteristics and response rate for regulation, reliability is the most important performance criterion for storage used to provide regulation. First, it must be a reliable resource for the NYISO. Second, to provide this service cost-effectively storage must make many low priced regulation "transactions." If storage used for regulation is off-line for "many" hours, it may not be cost-effective.

Efficiency is also an important criterion affecting cost-effectiveness because energy-related costs – due to storage *losses* – make the difference, on the margin, for many possible regulation transactions. That is, if storage losses and related energy costs are too high then storage operators may have to forgo so many otherwise profitable transactions that regulation is not profitable overall.

Discharge duration required for regulation ranges from several minutes to as much as an hour. One possibly helpful benchmark is Beacon Power's "Smart Energy Matrix" flywheel-based storage system whose 100 kW modules store 25 kWh of energy when fully charged, reflecting a fifteen minute discharge duration.

For more information, see Beacon's website:

http://www.beaconpower.com/products/EnergyStorageSystems/

Application Synergies

Conceivably, storage could provide regulation in addition to one or more other benefits.

Application #8 Transmission Support

Application Overview

Energy storage may be used to improve transmission and distribution systems' performance by compensating for electrical anomalies and disturbances, such as unstable voltage and voltage sag, and sub-synchronous resonance. The result is a more stable system with improved performance (throughput).

Readers should note that benefits from transmission support are very situation-specific and site-specific and that ancillary services provided by or via the NYISO do not include the transmission support application. It is presented here as a potential application for storage in New York. FERC refers to this service as Network Stability, which is defined as "real-time response to system disturbances to maintain system stability or security."

As context, historically, it was a technical challenge to provide "very rapid" response to load changes because large power plants that provide regulation tend to have a relatively slow response rate. Technological advances, such as modern power electronics, state-of-the-art communications and control, and superconducting materials, now make such a service practical.

Table 4 lists and briefly describes ways that energy storage provides transmission support.

Table 4. Types of Transmission Support

Type	Description
Transmission Stability Damping	Increase load carrying capacity by improving dynamic stability.
Sub-Synchronous Resonance Damping	Increase line capacity by allowing higher levels of series compensation by providing active real and/or reactive power modulation at sub-synchronous resonance modal frequencies.
Voltage Stability	1. Transient Voltage Dip Improvement Increase load carrying capacity by reducing the voltage dip which follows a system disturbance. 2. Dynamic Voltage Stability Improve voltage stability for increased energy transfer.
Under-frequency Load Shedding Reduction	Reduce load shedding needed to manage under-frequency conditions which occur during large system disturbances.

Adapted from information provided by the Electric Power Research Institute [1, 2, 4]

Notable Technical Considerations

Required capabilities for transmission support include: 1) very reliable operation, 2) high performance when storage is partially discharged, 3) sub-second response, and 4) ability to accommodate many charge-discharge cycles. For storage to be most beneficial for transmission support, it should provide real and reactive power. Typical discharge durations for this application range from a few seconds to twenty seconds. [4]

See Appendix R for additional details about two of the ways listed above that storage could be used for transmission support. For even more information, please refer to the EPRI-DOE Handbook of Energy Storage for Transmission and Distribution Applications [21], available online at: http://www.epri.com/OrderableitemDesc.asp?product_id=000000000001001834

2.d. Electricity End-user Applications

Application #9 Electric Service Reliability

Application Overview

For the electric service reliability application, energy storage provides highly reliable electric service when power from the grid is not available. Specifically, during power *outages* lasting for as little as one second, the storage system provides enough power so that loads can "ride through" the incident. If necessary, the storage system either a) initiates an orderly shutdown, or b) transfers loads to on-site generation for longer term power.

Presumably, loads protected are important or critical loads, for which power interruptions cause significant negative impacts related to some or all of the following: cost, productivity, security, and safety.

Notable Technical Considerations

Discharge duration for this application is quite circumstance-specific. If a transfer offload to onsite generation is the objective, then only a few minutes of discharge duration is needed. If the primary objective is to facilitate an orderly shutdown, then the discharge duration could be a few minutes to a few hours, depending on the processes and facilities involved.

Storage used for this application must reliably yield power with sufficient quality.

Application Synergies

This application is likely to be compatible with the power quality application. It could be compatible with the bill reduction application.

Application #10 Electric Service Power Quality

Application Overview

For the electric service power quality (PQ) application, storage shields sensitive loads against short duration poor power quality "events".

Key power quality event types include:

- brief service interruptions whose duration ranges from a fraction of a second to minutes
- variations in the primary (alternating current) frequency at which the power system operates – 60 cycles/sec
- variations in voltage (e.g. spikes, dips, and sags)
- low power factor
- harmonics, (i.e., the presence of currents or voltages at frequencies other than the primary frequency)

Sensitive loads are those that cannot tolerate poor power quality. Sensitive loads of interest are usually critical or important loads, such as those serving high value added processes, many types of electronics, and loads related to security and safety.

Notable Technical Considerations

The discharge duration required for PQ ranges from several seconds to as much as one minute.

Application Synergies

This application is likely to be compatible with the reliability application. It could also be compatible with the bill reduction application.

Application #11 Electric Service Bill Reduction: Demand Charges

Application Overview

One important potential use of energy storage is to reduce electricity end-users' electricity bill by reducing demand charges (demand charge reduction).

The two dominant components of the bill are: a) reduced cost for *energy,* and b) in some cases reduced *demand* charges. Energy charges are driven mostly by the type and amount of *fuel* used to generate electric energy. Demand charges address the power draw, from the end-user's loads during times when peak demand (on the grid) occurs. Power draw – demand – underlies the need for *equipment* needed to generate or transfer electric energy.

In New York, most rates tend not to make a significant distinction between times when energy is used. So, the entire benefit from storage used for this application relates to reducing demand when demand charges apply. To do that 1) energy is purchased when demand charges do not apply, and 2) that energy is discharged when demand charges do apply, so the end-user's demand is reduced.

For this application, it was assumed that commercial end-uses were most inclined to have a) the amount and pattern of electric demand and the financial incentive to make storage for bill reduction worthwhile, and b) the sophistication to evaluate or even to consider storage for bill reduction. As such, the tariff chosen for evaluation is Con Ed's PSC 9, full service tariff Service Class 9, Rate 1 (SC 9 Rate I).

Notable Technical Considerations

The maximum discharge duration for this application is determined based on the relevant tariff. The SC 9 Rate I specifies a six hour period during which peak demand applies. Therefore, the standard assumption for this application is six hours of discharge duration.

Because of the way demand charges are assessed, storage reliability is quite important. Demand charges are based on the maximum demand that occurs within a certain period such as a month or season (summer and winter), so no matter how infrequently the maximum demand occurs within the specified period (month or season), the demand charge is applied to the maximum demand.

Peak demand is determined as follows (per Consolidated Edison Company SC 9, Rate I; Original Leaf No. 44 Effective January 1, 1994): "The Maximum demand when determined by a demand meter shall be the highest 30 minute integrated demand occurring during the billing period in which such use is made. The integrated demand is the average of the kilowatt use occurring in a 30 minute period, which average, if used continuously for 30 minutes, would produce the kiloWatt hours actually consumed during such period."

Application Synergies

Depending on circumstances, the same storage system used for demand charge reduction might also be compatible with improved end-user PQ and improved electric service reliability. Indeed, the combination of demand charge reduction and reduced cost due to poor PQ could provide a good value proposition for commercial end-users with high value operations. When charging, aggregated storage could provide reserve capacity.

Application #12 Electric Service Bill Reduction: Time-of-use Energy Pricing

Application Overview

This classic electricity storage application applies to electricity end-users that either a) opt for service or b) are required to take service that is priced based on the "time-of-use" (TOU).

As with the buy low – sell high application, this application involves charging of storage at times when price – retail price in this case – is low, so storage may be discharged at times when price is high. The purpose is to avoid the need to purchase the expensive energy to serve the end-user's loads (rather than selling energy via the grid).

Notable Technical Considerations

Depending on how TOU pricing is structured, high reliability may or may not be important. Reliability is important to the extent that TOU *energy* prices are accompanied by *demand* charges. If the tariff does impose demand charges, then reliability is important because downtime of less than one hour – when demand charges apply – may have a significant effect on demand charges paid in a given month or year.

For Con Edison, time-of-use charges are dominated by demand charges, as described in Appendix S.

Application Synergies

This application has limited synergies with other applications, especially given the way the rates are structured. If storage used for this application is located in areas with congested T&D capacity, then storage may provide benefits associated with T&D deferral. When charging, aggregated storage could provide reserve capacity.

2.e. Renewables Applications

Application #13 Renewables Electricity Production Time-shift

Application Overview

The renewables electricity production time-shift application emphasizes the use of storage to store low value energy from renewables so that energy may be used when the value is high. For the entity purchasing the energy, this allows use of more renewable energy in lieu of producing or purchasing high priced, on-peak energy, primarily from conventional generation.

It is common for this application to involve a contract and/or power purchase agreement. In New York, this would occur via a bilateral contract. For this report, the application involves transmitting energy from wind generation in western upstate New York to storage in NYC. Energy is transferred when transmission congestion, T&D energy losses, and energy value are all lowest. Coincidently, wind generation in western upstate New York produces most energy at those times, a fortuitous synergy.

See Appendix M for details.

Notable Technical Considerations

The discharge duration for this application is circumstance-specific, depending mostly on the terms of the purchase agreement. The minimum discharge duration for this application is assumed to be two hours.

Application Synergies

This may be a very rich opportunity to aggregate benefits from storage, in part because there are several possible synergies depending on who owns the storage, what type it is, and the storage location(s). Storage used for this could also be used to: 1) avoid/defer need to build or to purchase generation capacity (ICAP), 2) avoid/defer need to build T&D capacity, 3) avoid transmission congestion charges, 4) improve service reliability, 5) reduce effects from poor PQ, and 6) provide ancillary services.

Application #14 Renewables Capacity Firming

Application Overview

For this application, storage is charged using energy from intermittent renewables, when demand and value for electric generation capacity (and energy) is relatively low. That energy is discharged when electric demand and power (capacity) supply cost is high.

Note that emphasis is on power and capacity, not energy. That is, the objective is to reduce need for power generation (ICAP in New York) and possibly T&D *infrastructure*, rather than reducing *fuel* use and possibly T&D losses.

The case evaluated for this report is customer-sited or otherwise distributed photovoltaics (PV) whose capacity is firmed using a relatively small amount of storage.

At first it may seem that PV is not the best choice for firming, given that PV output tends to be somewhat coincident with peak demand; however, there is a good rationale for doing so. In short, for a variety of reasons, PV systems are rarely installed so that output is as optimized to serve system or even local peak. Given that solar generation output is already somewhat to very well correlated with peak demand, a somewhat modest amount of storage firms up PV output during peak demand periods.

In summary, this case was chosen for several reasons, including:

- modest amounts of storage firms up PV output, so PV can be a high value capacity resource
- inherent synergies between PV and storage subsystems, especially inverters
- the on-site storage can provide additional service, such as providing reliability and protection from poor PQ
- a growing preference for renewables, in general, coupled with challenges associated with developing meaningful levels of wind generation capacity (and most other generation using renewable fuels) in or near NYC
- a recent study indicates that a relatively small amount of energy storage (e.g. two hours) used in conjunction with photovoltaics can significantly increase the grid capacity value of a “fleet” of PV systems with various orientations. [17]

Technical Considerations

It is assumed that two hours of storage increases the average full load output during peak demand periods – relative to PV alone – from 40% to nearly 100%. [17] Furthermore, it is assumed that 1/2 hour of storage is needed for reliability and/or PQ purposes – a conservative and admittedly arbitrary value that could range from a few seconds to an hour or more for typical circumstances.

Application Synergies

Depending on the location, storage used to firm up renewables generation could be used for applications beyond grid capacity, such as 1) reduced cost due to inadequate PQ and due to outages, 2) reduced (net) cost for on-peak energy purchases, 3) avoided/deferred need to build transmission capacity, and 4) avoided transmission congestion and access charges and T&D losses.

Please see Appendix O for a few more details.

2.f Application-Specific Discharge Durations

Table 5. lists assumptions for discharge duration specific to each application.

Table 5. Discharge Durations for Applications

#	Application	Discharge Duration (hours, except as indicated) Low	High	Notes
1	Electric Energy Buy Low – Sell High	2	8	Primarily a function of: 1. incremental cost of adding storage versus incremental benefit (benefit from additional transactions) and to a lesser extent, 2. storage efficiency.
2	Electric Supply Capacity	2	6	Needed during system peak demand periods.
3	Reduce Transmission Capacity Requirements	2	6	Needed during system peak demand periods.
4	Reduce Transmission Congestion	2	6	Needed during system peak demand periods.
5	Transmission and Distribution Upgrade Deferral	2	6	Needed during local peak demand period.
6	Operating Reserve	10 Minutes	1	Short duations to pick-up load rapidly so "fast-response" generation has orderly, cost-effective ramp-up. Longer durations provide reserves in lieu of "slow start" generation.
7	Regulation and Frequency Response (Regulation)	10 Minutes	1	Depends on longest a) period between and b) duration of each up and down regulation "event."
8	Transmission Support	2 Seconds	5 Seconds	Used to ameliorate effects of very short duration anomalies, for stability.
9	Electric Service Reliability	5 Minutes	5	Very circumstance-specific. As needed, per outage history, for ride-through and/or orderly shutdowns.
10	Electric Service PQ	10 Seconds	1 Minute	Very circumstance-specific. As needed, per PQ history, to minimize cost for damage & productivity losses.
11	Electric Service Bill Reduction: Demand Charges	4	6	Driven by tariff or relevant energy pricing and to some extent end-user peak demand profile. Typical peak demand (and energy price) periods range from 4 to 6 hours.
12	Electric Service Bill Reduction: Time-of-use Energy Prices	4	6	Driven by 1) end-user peak demand profile, 2) demand charges and structure, and 3) time-specific energy prices.
13	Renewable Electricity Production Time-shift	4	6	Purpose: store renewable energy, off-peak for use on-peak. Driven by renewables production pattern, peak demand period and pattern, peak capacity and energy value. Assumed 5 hours for NYC.
14	Renewables Capacity Firming	1	3	Driven by timing of peak demand and PV production and by energy and capacity value. Assumed 2.5 hours in NYC.

2.g. Other Applications

Reactive Power (VARs) for Voltage Support – System and Local

Transmission voltage support, an ancillary service provided by the NYISO, was not evaluated for this report based on the premise that storage would have a very challenging time competing with generation for reactive power market share, based mostly on the current and expected price paid for the service, nor was storage evaluated for Voltage support at the distribution level, mostly because the conventional solutions are relatively inexpensive.

Nonetheless, state-of-the-art electricity storage systems, especially those with reasonably sophisticated power electronics (for conditioning and converting power), can serve this application by providing reactive power.

Furthermore, authors do recognize the potential for energy storage as an important element of a robust approach to region-wide grid stability during power interruptions, especially those characterized by declining Voltage. First, storage can respond rapidly (often within milliseconds), whereas generation resource may take a few to many minutes to respond fully. Second, reactive power, needed to stabilize Voltage, cannot be transmitted very far, so local sources are most helpful, especially if interruptions involve transmission corridors.

Aggregated modular storage deployed at or near loads, for reasons other than Voltage support, could provide very helpful Voltage support when and where needed. Third, by picking up specific types of load when grid anomalies occur, especially small motors such as those used in small air conditioning equipment, storage reduces Voltage degradation on the grid, reducing the chances of cascading outages.[27] See Appendix J for additional details.

Uninterruptible Power Supplies, UPSs

This report does not address the existing uninterruptible power supply (UPS) market, per se. However, the reliability and PQ applications that are addressed in this report do, probably, represent extensions of the existing UPS market. And some of the market potential assumed in this report may currently be served by UPSs.

The following is based on information available from the website of market research firm Frost and Sullivan. [18] The worldwide market for UPSs in 2003 was $4.7 billion and will grow to an estimated $6.94 billion by 2010 on sales of an estimated 31.5 million units. Demand growth was somewhat flat in the years just before 2003, due in part to market saturation. However, according to Frost and Sullivan, “The North East Blackout of 2003 has had a strong influence on demand.”

Roughly half of revenue and 91% of unit sales involve UPSs rated below 5 kVA – mostly ranging from 300 VA up to 1 kVA. UPSs whose rating is 5 to 50 kVA account for one quarter of sales revenue and 8% of unit sales. UPSs whose rating is above 50kVA account for about one quarter of sales in dollars and 1% of unit sales.

Regarding notable institutional preferences, Frost and Sullivan note that “some end users prefer decentralized protection [relative to facility wide systems because they allow for]…redundancy and therefore higher reliability…though for larger organizations and datacenters, centralized protection is considered more economical."

Batteries for Substation Operations

It is interesting to note that most utilities already have at least some experience with reliable modular energy storage. In fact, there are an estimated 100,000 battery storage systems used for on-site loads at substations, especially for emergency power needs (i.e., they must be very reliable). Such battery storage systems have power output ratings that are typically in the tens of kWs, with discharge durations of eight hours. [3] (The authors have not attempted to ascertain the extent of such battery use by Con Edison.)

Enabling Curtailable Loads

One important way that modular/distributed storage could make a significant contribution is that it could be used to facilitate or enable additional curtailable load. Storage does that by picking up load when a load curtailment event is initiated; to either a) enable an orderly shutdown, or b) carry load for the duration of the event.

Under terms of Rider O of Con Edison's tariffs (which defines terms of the curtailable load program):

- Entities located within a designated network may receive a monthly payment in return for an agreement to shed load in increments as small as 50 kW. Payments are specific to the location of the curtailed load. (Networks are specified in Statement of Networks Eligible for Rider O.)
- Applications are accepted for load totaling as much as 125% of the requested megawatt reduction.
- Curtailments may be called weekdays between the hours of 8:00 A.M. and midnight during the Summer Billing Period.
- Curtailments will last between four and eight hours.
- Participants may opt to provide load reduction for a specified maximum number of curtailments during the Summer billing period as follows: a) up to 5 curtailments, b) up to 10 curtailments, and c) more than 10 curtailments.

Rider O – and all other riders – are available at Con Edison's website at http://www.coned.com/rates/elec-sched2.asp

Modular Energy Resources for T&D Risk Management

Risk is inherent in any investment decision, due to uncertainty about what the future holds. Investment in T&D is no exception, though risk is not evaluated robustly when making T&D investment decisions. Uncertainty that drives T&D investment risk includes load growth uncertainty and uncertainty about whether project delays, for various possible reasons, could lead to T&D equipment overloading.

Modular capacity additions that are possible using modular storage, generation and even demand management give T&D planners and engineers the ”option” of using “small” modular solutions on the margin to serve load on the margin instead of adding a large “lump” investment associated with conventional T&D equipment (The term lump refers to the fact that, typically, 25% to 50% capacity is added when conventional T&D upgrades are made).

Of course, modular options have risk too, especially due to Undersizing. But, giving power engineers the option of using modular or lumpy solutions could lead to a more optimal T&D investment portfolio on a risk-adjusted cost basis.

T&D Equipment Life Extension

As T&D engineers’ means to gauge T&D equipment’s remaining life improves (e.g. based on actual loading history and using increasingly sophisticated models), it is conceivable that modular energy resources could be used to extend the life of some types of T&D equipment, especially expensive equipment such as underground cables.

Improved Air Quality

Depending on how, where, and when storage is charged and discharged and depending on the source(s) of energy for charging, storage could have a positive impact on NYC air quality and could result in less air pollution overall. Positive effects are possible if a) storage is charged using high-efficiency baseloaded fossil-fueled power plants, and/or b) storage allows for more constant generation output, and/or c) storage allows for less use of inefficient “peakers,” and/or d) storage is charged using electricity from renewable resources.

End-user-owned emergency generators used as a capacity resource face increasing challenges as air quality related constraints, especially those regarding oxides of nitrogen and particulate, tighten. Storage could provide some of the service expected from those emergency generators without the in-city or real-time emissions.

Fuel Savings

Similar to improved air quality, depending when and where electricity storage is used and the sources and locations of charging, energy storage could be part of an overall fuel savings program. As shown in Figure 2, consider a proxy heat rate for a “high efficiency” power plant of 7,000 Btu of fuel input per kWh of electricity out (49% fuel efficiency). Similarly, consider the proxy heat rate of 10,500 Btu/kWh for a ”low efficiency” power plant. If 80% efficient storage is charged with energy from the efficient power plant, the effective heat rate – net of storage losses – is 7,000 Btu/kWh ÷ 80% = 8,750. However, if storage is only 70% efficient the effective heat rate is 7,000 Btu/kWh ÷ 70% = 10,000.

For perspective, at the beginning of 2006 there was only one high efficiency central generation facility (rated at 80 MW or greater) in NYC. Its heat rate is approximately 7,000 Btu/kWh. Other large generation units (whose rating exceeds 80 MW) have heat rates exceeding 11,000 Btu/kWh.

Further, if storage allows for more use of electric energy from renewables – especially wind and hydroelectric – then *fossil fuel* is saved (conserved).

Also, storage can be used to reduce fuel risk by allowing for fuel diversification and by reducing need for fuel during periods of peak electricity demand, when fuel price and availability related uncertainty is most significant.

A less significant facet of storage for fuel savings is that because many types of storage can respond much more rapidly than power plants, storage can be used for the short duration changes in load, so generation plants can maintain a more stable, fuel-efficient, cost-effective output level. That is one element of a group of generation-based benefits from storage called dynamic operating benefits.

Finally, depending on what energy is used to charge storage and storage location, T&D energy losses avoided could be on the order of several percentage points.

3. Estimating Market Potential

A key criterion affecting the merits of a market opportunity for storage systems is the magnitude of possible demand for storage (maximum market potential). For this report, the criterion of merit for market potential is MW. That is, maximum market potential is defined as the portion of load (in units of MW) for which storage systems might be used for a given application.

This section 1) describes the authors' approach to developing high level estimate of maximum market potential, and 2) presents maximum market potential estimates. It is based on the authors' subjective interpretation of prevailing market conditions; conditions that are evolving.

Note that storage system *power* (MW) is not the only important measure of market potential. To the energy storage industry, another important market potential indicator is market potential for what might be called energy storage "reservoir" equipment. That is the equipment (storage subsystem) in which energy is actually stored, such as batteries and individual flywheels (units are MWh or kWh). To calculate market potential for that equipment for a specific application, multiply energy market potential in units of MW times the application-specific discharge duration. For example, if market potential is 500 MW, and the discharge duration is 3 hours, then the market potential for energy reservoir equipment is 500 MW * 3 hours = 1,500 MWh.

3.a. Market Estimation Philosophy and Approach

3.a.1. Philosophy

The authors note that the discussion about market estimation in this document, by design, cannot address the many combinations of existing and future market conditions, storage costs and benefits, or costs and benefits for substitutes, especially demand response and distributed generation. So, readers are encouraged to consider technical market potential estimates in this report to be *suggested* values, to be used as helpful indicators or as a point of departure for stakeholder-specific evaluations.

As a framework for estimating market potential, the authors suggest a generic, three-step framework for making market estimates, depicted in Figure 4. The framework is used to make market potential estimates with the necessary precision, with rigor ranging from high-level and screening-level to detailed and precise.

As shown in Figure 4, the first step is to establish the technical market potential (or technical potential). That is the maximum amount (MW) that is possible given broad technical constraints. As an upper bound for energy storage, the technical potential is all peak electric demand within a given load category and/or geographic area.

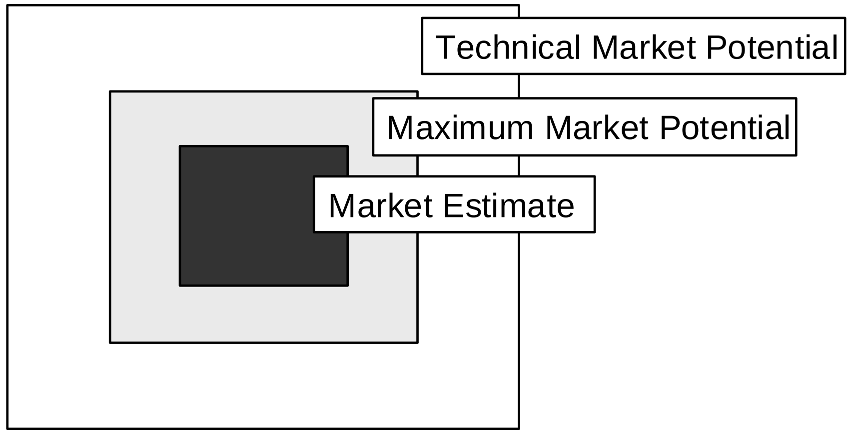


Figure 4. Market Potential and Estimate

The next step is to estimate maximum market potential, which is a subset (portion) of technical market potential. Maximum market potential is the highest possible demand given constraints that are practical or institutional in nature such as utility regulations and practices and the fact that utilities are unlikely to retire existing equipment to accommodate storage.

Maximum market potential is established without regard to storage cost.

Finally, step 3, the most challenging part of the process, is making the actual “market estimate”. That is the portion of the maximum market potential that is actually exploitable, including consideration of storage cost and substitutes. The market estimate reflects the amount of storage that the analyst expects to be deployed, over a given period, for the specified application or combination of applications.

3.a.2. Approach

As noted above, market estimates may be as detailed and precise as appropriate. At the very least, various levels of market potential can be tested for reasonableness using various combinations of judgment, knowledge, or preliminary product cost estimates.

Alternatively, bases for estimates could include, for example, sales trends and projections, surveys, analysis of utility capital budget plans, detailed product cost estimates, or market research or intelligence.

For this report, the authors provide an auditable estimate of maximum market potential. In all cases the premises, assumptions, and rationale used may or may not be consistent with the way other stakeholders might assess market potential, so stakeholders are encouraged to apply the appropriate rationale and assumptions as necessary.

3.b. New York Zone J Electric Demand

A key basis for estimating maximum market potential is the total peak electric load in New York Zone J. The load in 2006 and the load growth for the years 2007 to 2015 are shown in Table 6., below.

Table 6. New York Zone J Peak Load and Load Growth

New York Zone J Projected Load, Beginning 2006	11,628 MW
Average Peak Load Growth Rate	1.3% per year
New York Zone J Load, Ending 2015	13,060 MW
New York Zone J Load Growth 2006 to 2015	1,433 MW

3.c. Maximum Market Potential for Applications

The maximum market potential is an *upper bound* for market potential when considering practical and institutional factors that limit the potential. It is a portion of technical market potential. Maximum market potential is established without regard to storage cost.

For example, consider the premise that it is unlikely storage will displace any existing utility equipment that has useful life remaining. Given that premise, the highest possible maximum market potential for storage used in lieu of electric supply capacity (ICAP) is annual load growth.

Another example is maximum market potential for applications involving high value commercial end users, which includes a portion of the total commercial load.

Estimates for ten-year maximum market potential in New York Zone J, for the applications listed in Section 2, are shown in Table 7. The table also includes notes about the rationale used to set those values. Estimates are based on a blend of subjectivity, judgment and facts (data).

These values reflect expected market conditions and regulations. They are likely to be somewhat to very different if there is significant additional unforeseen market penetration of competing options, especially energy efficiency, demand response and distributed generation.

Table 7. Ten-year Energy Storage Maximum Market Potential Estimates for New York City

#	Application	MW 10 Years	Maximum Market Potential
1	Electric Energy Buy Low – Sell High	3,265	25% of Peak load[1] and of load growth[2] -- storage cannot compete with intermediate, baseload gen.
2	Electric Supply Capacity	3,739	ICAP required in 2006 -- 2,306 MW -- plus all load growth for next nine years. (Does not include reserve capacity or capacity provided via bilateral contracts.)
3	Reduce Transmission Capacity Requirements	3,759	Portion of in-city peak demand not served by in-city generation (20%) plus peak load growth. (Does not include reserves or capacity via bilateral contracts.)
4	Reduce Transmission Congestion	2,612	Portion of NYC peak demand not served by in-city generation (20%) plus growth[2] thereof. (Does not include reserves or capacity via bilateral contracts.)
5	Transmission and Distribution Upgrade Deferral	411	All T&D Upgrades: 1/30 of peak load each year (assume 30 life); average 411 MW/year. Assume that storage can defer 10% of that amount, plus growth.
6	Operating Reserve	445	Premise: generation is at least 2/3 of reserves. Storage: 1/3 of operating reserves (1/3 of 1,200 MW = 396 MW) plus growth[2] of that portion (49 MW).
7	Regulation and Frequency Response (Regulation)	281	Current market size for regulation (statewide) plus growth[2].
8	Transmission Support	70	1/4 of existing market size for regulation (statewide) plus growth of that share.
9	Electric Service Reliability	842	1/4 of SC9 (tariff/customer class) load plus growth[2] of that load.
10	Electric Service PQ	337	10% of SC9 (tariff/customer class) load plus growth[2] of that load.
11	Electric Service Bill Reduction: Demand Charges	1,685	1/2 of SC9 (tariff/customer class) load plus growth[2] of that load.
12	Electric Service Bill Reduction: Time-of-use Energy Prices	270	8% of SC9 (tariff/customer class) load plus growth[2] of that load, for "peak clipping."
13	Renewable Electricity Production Time-shift	2,700	2,700 MW in Western upstate New York (per G.E./NYSERDA study).
14	Renewables Capacity Firming	188	1% of peak load (116 MW) and 5% of all load growth (72 MW).

Notes
1 Peak Load in 2006 = 11,627 MW.
2 Peak load growth rate = 1.30%/year

A key premise for estimates: it is unlikely that *existing* resources/equipment will be removed from service to accommodate the addition of storage.

3.d. Making the Estimate

The final and most challenging step in the market estimation process is to establish the market estimate. It is the portion of the maximum market potential that will be realized.

As noted before, market estimates should be as detailed, accurate, and precise as necessary. At a minimum, various market estimates (levels) can be tested for reasonableness using a combination of judgment, knowledge, partial information, preliminary product cost estimates, etc.

At the other end of the spectrum are more detailed and sophisticated evaluations with bases such as consistency with sales targets, sales and market trends and projections, analysis of relevant utility capital budget plans and rate case filings, detailed product cost estimates, or surveys and other market research or intelligence gathering and analysis.

Market Estimates: Storage Must be Cost-Effective

One obvious driver of the market potential for storage systems used for a given application or application(s) is the value proposition to be demonstrated and its relationship to cost. Specifically, if lifecycle cost for storage systems is higher than lifecycle benefits, then, of course, no storage systems would be sold. If benefits exceed cost by a large margin, then the amount of storage actually used could be significant.

Key cost-related factors affecting market estimation for storage include: system price (capital, installation, O&M, etc.), efficiency, marketing costs, and market adoption rates (to the extent that it affects scale-up and resulting economies-of-scale).

Market Estimates: Storage Must be Cost-Competitive

Because the benefits associated with applications are estimated without regard to whether serving the application with storage is actually practical or cost-effective, it is important to note that competitiveness of any specific solution, including storage, depends on whether there is a lower cost and otherwise viable option.

So, when making the market estimate, it is important to account for the fact that solutions whose costs are not cost-competitive are probably not the most attractive candidates. Specifically, storage cost cannot exceed the cost of another technically and institutionally viable option (i.e., an option can be used to provide the same “utility”), or storage is not a financially competitive solution.

Market Estimates for Combined Applications and Benefits

In many cases, storage may be used for more than one application (combined applications), or storage used for a specific application may provide more than one financial benefit (combined benefits). (Financial benefits are described in Section 4.)

When making market estimates for these circumstances, it is important that these estimates account for the fact that combining benefits probably increases storage system benefit ($/kW) but may reduce the overall market potential. That occurs because it is unlikely that all entities using storage for individual applications will need storage for a combination of those applications.

Please see Section 5 for more on the subject of combining benefits.

4. Storage Financial Benefits

This section discusses estimation of the financial benefits from storage if used for the fourteen applications described in Section 2, which are summarized in Table 8. It also addresses the benefit related to avoided T&D losses.

Table 8. Benefits Summary

#	Application	Benefit $/kW Year 1	Benefit $/kW 10 Years
1	Electric Energy Buy Low – Sell High	55	394
2	Electric Supply Capacity	105	753
3	Reduce Transmission Capacity Requirements	13	93
4	Reduce Transmission Congestion	10	72
5	Transmission and Distribution Upgrade Deferral	500	1,200[1]
6	Operating Reserve	36	258
7	Regulation and Frequency Response (Regulation)	110	789
8	Transmission Support	24	169
9	Electric Service Reliability	50	359
10	Electric Service PQ	100	717
11	Electric Service Bill Reduction: Demand Charges	150	1,076
12	Electric Service Bill Reduction: Time-of-use Energy Prices	230	1,649
13	Renewable Electricity Production Time-shift	116	832
14	Renewables Capacity Firming	45	323

Notes

1 Transportable storage could provide a single year benefit at several locations. The benefit amount shown reflects two or three deployments over ten years.

General note: 10 year estimates do not reflect changes that would occur if there is significant market penetration of competing distributed/modular options (i.e., demand response, distributed generation) or a significant increase in in-city generation.

4.a. Financials

The following key assumption values are used to generalize and to simplify the example calculations in the following subsections. These values are used for all financial calculations so that all benefits are expressed using common bases. Certainly, analysts are encouraged to recalculate benefits using criteria appropriate for the circumstances at hand.

Financial Life

A plant life of 10 years is assumed for lifecycle financial evaluations. Certainly, a given storage system may last more or less than ten years. Ten years was selected so that all benefits may be expressed using common bases.

Price Escalation

A general price escalation of 2.5% is assumed during the storage plant's ten year financial life. Electric energy and capacity costs and prices are also treated as if they escalate at 2.5%.

Discount Rate for Present Worth Calculations

A discount rate of 10% is used for present worth calculations; to estimate lifecycle benefits over the storage system's financial life.

Present Worth Factor

The following approach was used to simplify present worth (PW) calculations in examples that follow.

The present worth of a stream of otherwise equal payments is a function of the price/cost escalation and the discount rate assumed. From above, for all costs and prices the standard (cost/price) escalation rate is 2.5% per year and the standard discount rate is 10%. A mid-year convention is used for this report.

The "present worth factor" (PW factor) is used to simplify calculation of the ten year, discounted lifecycle benefits for applications. The PW factor is the sum of year-specific present worth values, for each of the ten years in the evaluation.

Each year's present worth reflects the first year value adjusted to reflect the respective number of years of price/cost escalation and the respective number of years of discounting. Mid-year convention was used. The formula is as follows:

$$\sum_{i=1}^{10} \frac{(1+e)^{i-.5}}{(1+d)^{i-.5}}$$

e = annual price escalation rate (%/year)
d = discount rate (%/year)
i = year

Figure 5., below, shows present worth factors for a range of lifetimes, for discount rates of 7%, 10% and 13%, reflecting 2.5% price/cost escalation.

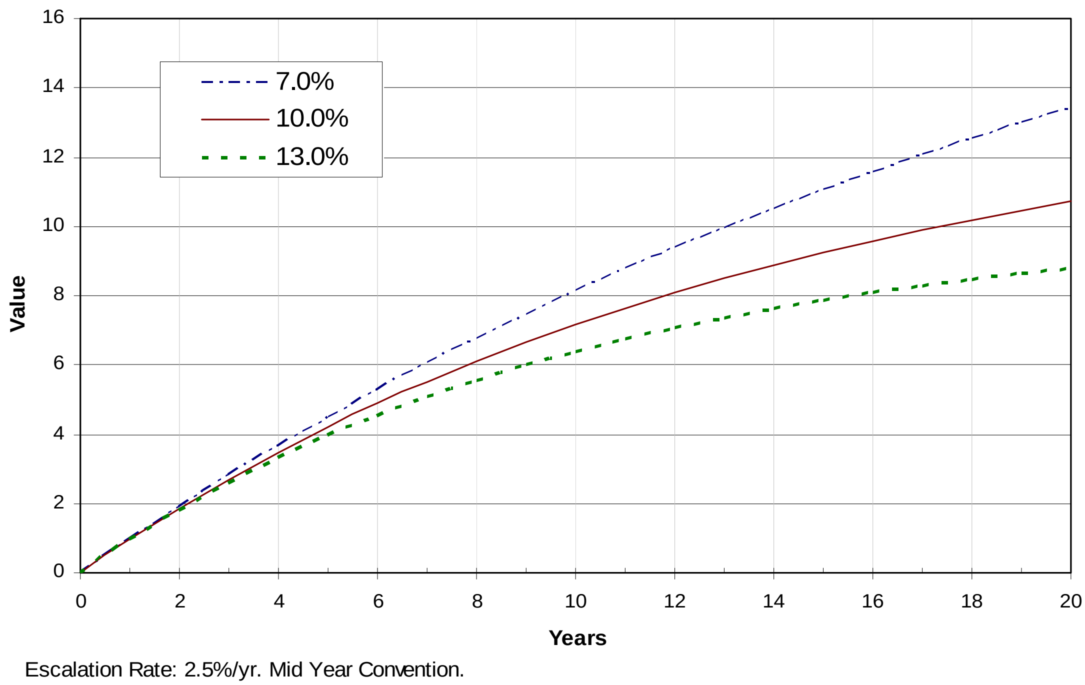


Figure 5. Present Worth Factors for Price Escalation of 2.5% and for Discount Rates of 7%, 10%, 13%

Consider an example: For an annual/first year benefit of $100/kW-year. The ten-year lifecycle benefit is calculated by applying the PW factor to the first year value:

$100/kW year * 7.17 = $717/kW.

(See Section 5 for more on the subject of combining benefits.)

To be clear, this approach treats *annual* benefits for all 10 years considered as if they are the same magnitude as the first year, except that the financial value of the benefit escalates at 2.5%.

Stakeholder Perspective

Benefits are estimated without giving much regard to stakeholder perspectives. In reality, some of the values described as benefits in this report may have external or ancillary costs that offset some or all benefits identified, and others, though real, may not be "shared" or "transferred" effectively – due to existing utility market mechanisms. Nonetheless, it is important to evaluate the magnitude of such benefits to understand the stakes, so that necessary changes can be considered.

Lost Revenue

Benefit calculations are estimated without regard to possible effects due to lost revenues. Specifically, to the extent that utility revenues are reduced and fixed costs are not, the net effect may be to increase payments by utility customers that do not derive a "benefit." In most cases, actions that cause such a cost-shift to non-participants are subject to regulatory responses ranging from monitoring of developments to prohibiting the activity.

Suboptimal Use of Capital

It is unlikely that utilities will defer or avoid investments if doing so reduces stockholder returns, or worse yet, if doing so means that even a modest portion of investors' capital is not invested. For this document, this is especially relevant to the T&D deferral application.

Note that for the period 2005 to 2008 Con Edison does not have a financial disincentive to promote demand reduction, unlike most other utilities that must invest in new capacity to generate authorized rates of return for investors.

Storage Non-energy Variable Operating Cost

In some cases, the net benefit for a given transaction must be calculated before determining whether or not a transaction is attractive. Consider an example: energy is worth 10¢/kWh when it is discharged from the storage system. That transaction should be made only if the 10¢/kWh exceeds the cost to purchase energy used for charging (including losses) plus non-energy variable operating costs.

In those cases, the transaction total cost is calculated. It is based on the charging energy price, storage efficiency, and storage *non-energy* variable operating cost (VOC) per kWh of energy discharge.

Cost = (Charging Energy Price ÷ Storage Efficiency) + VOC.

VOC reflects wear and tear on the storage system that occurs with each charge/discharge cycle. Dividing by storage efficiency accounts for the fact that extra energy must be put into storage (purchased at the charging energy price) to make up for storage losses.

4.b. Benefits for Applications

Benefit #1 Electric Energy Buy Low - Sell High

Introduction

To estimate the buy low - sell high benefit, a dispatch algorithm is used to determine when to charge and when to discharge storage; to maximize the net financial benefit.

Specifically, the algorithm determines when to buy and when to sell electric energy, based on a) the current market price (closely linked to DAM LBMP) for charging energy, b) cost to store and discharge storage, including non-energy variable operating cost and energy losses, and c) the expected sale price (also closely linked to DAM LBMP) for the energy.

Approach

The dispatch algorithm used evaluates a time series of hourly energy prices to identify buy and sell transactions that yield a net benefit (i.e., benefit exceeds cost). The algorithm sums net benefits from all such transactions to calculate annual benefit.

Net benefit for a given transaction is calculated as follows:

$$(\text{Charging Energy Price} \div \text{Storage Efficiency}) + \text{VOC}.$$

If the prospective sell price exceeds that amount, then the transaction is profitable, and it is made (by the algorithm).

Note that results reflect what might be called “perfect knowledge.” That is, a predetermined series of prices was used. In effect, at any given hour in the year, the algorithm “knows” what prices will be at any other hour of the year. In reality, of course, the price at a later time is not known. Ideally, a dispatch algorithm would rely on forecasts like those used currently for electric supply and demand based on such criteria as historical and projected loads, season, historic and forecast weather, whether a given day is a holiday, weekday or weekend day, and the mix of loads being served.

Note that the algorithm, as described, estimates the *annual* benefit for a specific year. It is converted to a ten year present worth as described below.

Energy Prices

For this report, the chronological hourly price data used were Location Based Marginal Prices (LBMPs) in the day-ahead market (DAM) for Zone J (NYC) in 2005. 2005 prices are escalated by 2.1%. [7] Figure 6. shows prices for the entire year. Figure 7 shows a “price duration curve” with hourly prices arranged by magnitude.

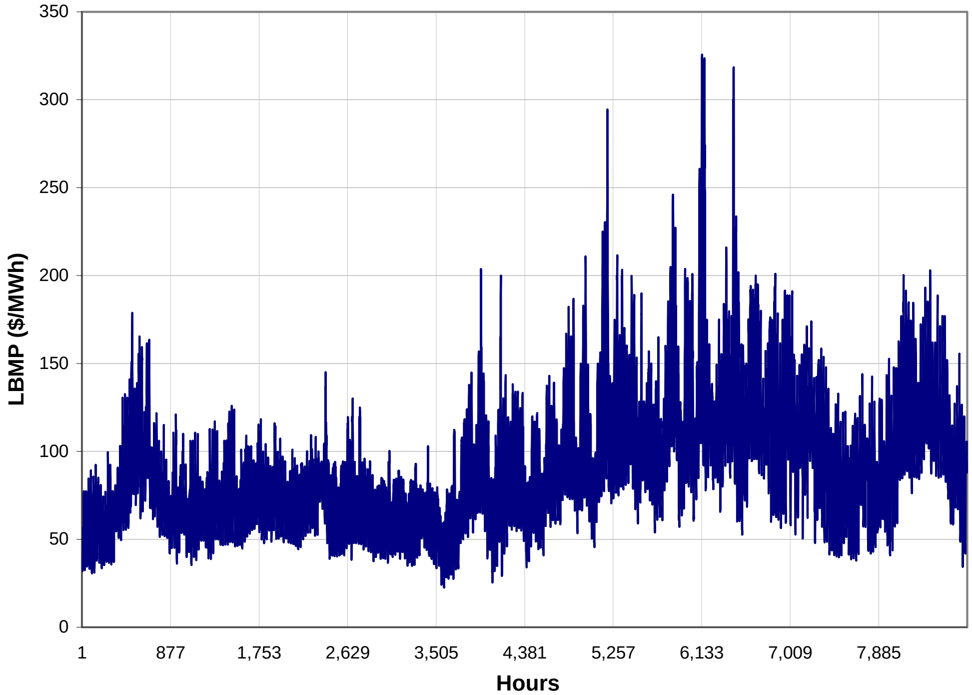


Figure 6. LBMP DAM Energy Prices
for New York Zone J, 2005 +2.1%, Chronological Order

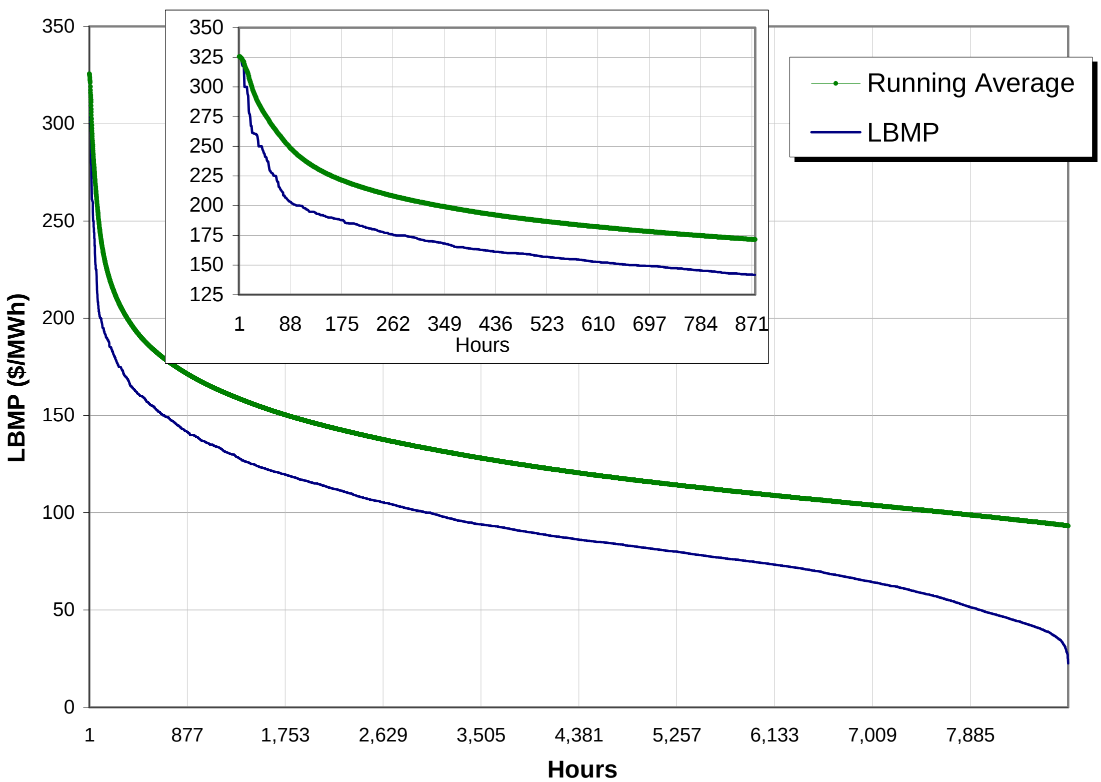


Figure 7. LBMP DAM Energy Prices
for New York Zone J, 2005 +2.1%, Magnitude Order

Table 9 shows the average value of the LBMP a) during the 200 hours of the year when prices where highest ($222.1/MWh) and b) during the 10% of the year when energy prices were highest ($175/MWh). The average for all hours of the year was $95.3/MWh

Table 9. LBMP Price Highest 200 and Highest 10% Annual "Price Hours"

Portion of the Year	10.0%	200 Hours
Total ($/MW)	153,344	44,311
Average ($/MWh)	175.05	221.56

For more information about LBMPs in New York see Appendix D.

Annual Benefit

Benefits are estimated for storage plants whose discharge duration ranges from one hour to eight hours. Figure 8 shows estimates for storage plants in New York Zone J whose efficiency ranges from 70% to 90% and whose variable operating costs (VOC) are 0¢/kWh, 2¢/kWh, and 4¢/kWh.

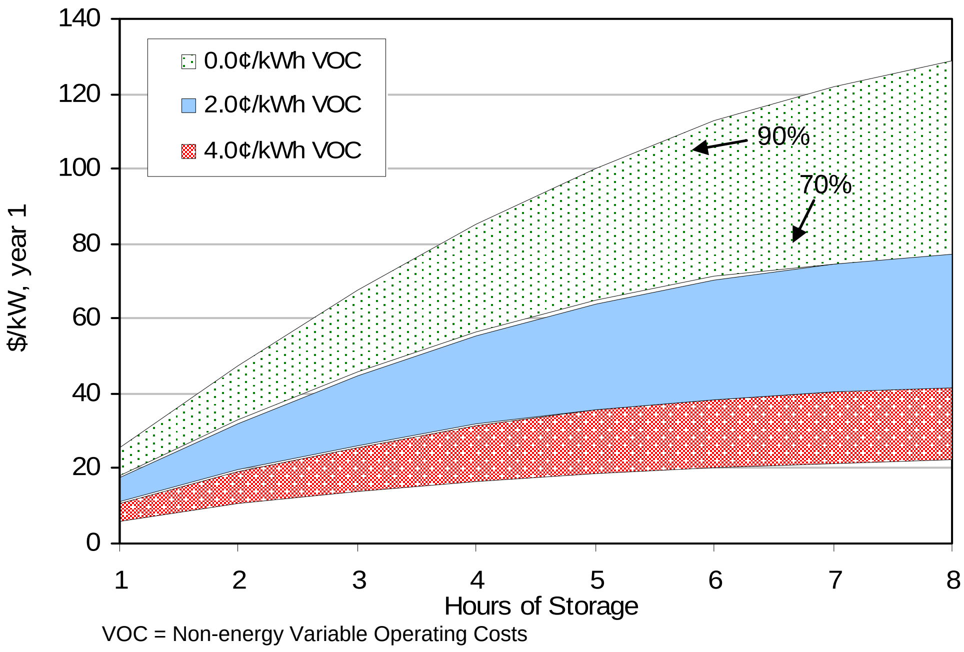


Figure 8. Single Year Buy Low – Sell High Benefit

As Figure 8 indicates, as hours of storage discharge duration are added, the incremental and total benefits increase and then begin to level off. This reflects diminishing benefits per buy/sell transaction (i.e. the average price differential diminishes as more and more transactions occur during the year.)

As the figure above shows, storage VOC (per kilowatt-hour stored and then discharged, not including cost for charging energy) has a dramatic effect on benefits.

Lifecycle Benefit

The values calculated above are for one year. To convert the single-year value to present worth the first year benefit is multiplied by the present worth factor of 7.17. Results are shown in Figure 9.

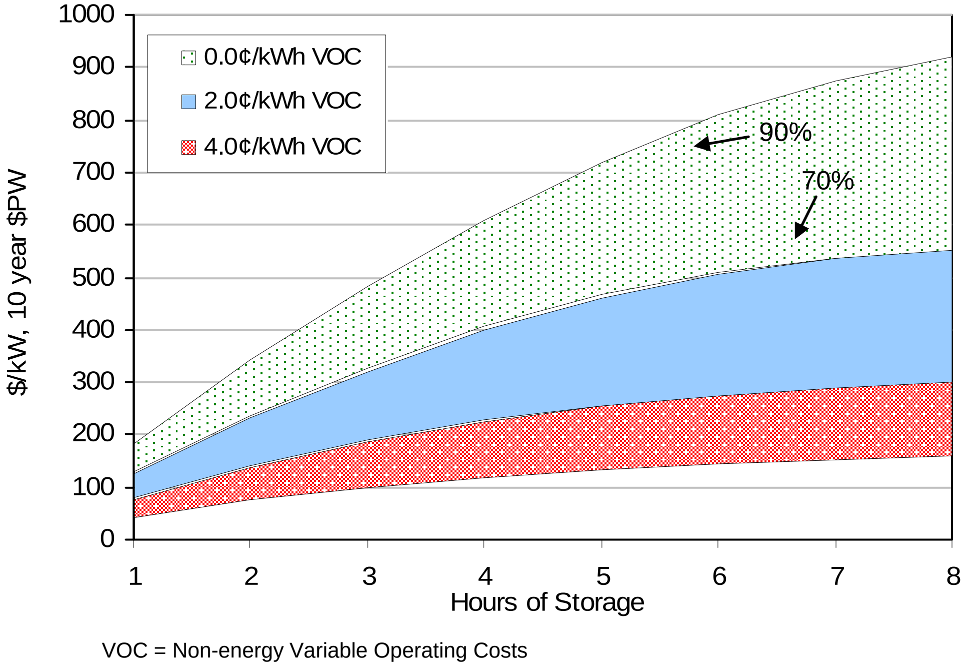


Figure 9. Ten Year Present Worth Buy Low – Sell High Benefit

Based on results, a reasonable estimate of the benefit from buy low-sell high application is about $200/kW to$300/kW.

That value is lower than most experts expect. However, those expectations are often based on familiarity with existing large scale energy storage projects, primarily using pumped hydroelectric systems with relatively low VOC. As shown from the results, VOC has a large impact on results. More modular storage has VOC of several cents/kWh whereas existing pumped hydroelectric storage plant has a relatively low VOC, perhaps less than one cent per kWh.

Benefit #2 Electric Supply Capacity

Introduction

Storage used in such a way that it provides the equivalent of electric supply (generation capacity) is assumed to have value like that of ICAP (installed capacity) in New York, and in this case, NYC.

Approach and Assumptions

The prevailing price for ICAP in NYC in 2006 is about $105/kW. Arguably, that is the maximum possible value for perfectly reliable storage that operates when obligated. Though such perfect reliability is not possible, if it is assumed that storage capacity is provided by several or even many modular/distributed units with good "diversity," then overall reliability could be quite high. At minimum, it is reasonable to say that storage used for ICAP must operate in such a way that it actually offsets the need for other ICAP (primarily generation).

Benefit

ICAP prices reflect results of an auction for capacity needed to serve in-city load. Capacity needed is to serve load that exceeds capacity provided via bilateral contracts plus capacity from in-city generation. Read more about ICAP in Appendix C.

Resources that operate during several hundred or more hours during the year, when electric demand and incremental capacity value are highest, are assumed to receive a significant portion or all of that ICAP credit. For example, for the Renewables Electricity Production Time Shift application it is assumed that energy from wind generation is transmitted to storage in NYC, so the storage can discharge during the 1,300 highest demand hours in the year. For that application the entire capacity credit is assumed.

Applying the PW factor of 7.17, the lifecycle benefit for a perfectly reliable storage plant used for ten years to provide ICAP in NYC (based on the price in 2006) is:

$105/kW-year * 7.17
= $753/kW

In reality, storage would probably provide some portion of that value.

Benefit #3 Reduce Transmission Capacity Requirements

Introduction

Utilities that use transmission facilities owned by other entities must pay a "rent" to the transmission owners (TOs) for transmission "service." In New York, the market-based version of that rent takes the form of a transmission service charge

(TSC). TSCs are regulated prices that cover TOs' revenue requirements for the transmission equipment.

Please see Appendix G for more details.

TSC rates are updated monthly and are posted at the NYISO website at http://www.nyiso.com/public/market_data/pricing_data.jsp

Approach and Assumptions

TSCs are assessed on a per-MWh transmitted basis, and they are set monthly to ensure that TOs' revenue requirements are met. After a survey of values for 2005 and early 2006, the authors concluded that an average charge of $3/MWh should be assumed as a good indication of the value. That TSC is applied for 1,300 hours per year.

Benefit

If the TSC avoided is $3 per MWh transmitted for 1,300 hours per year, the annual value is about $3,900/MW or $3.9/kW-year. For this report, assume a value of $4/kW-year.

Applying the 7.17 PW factor, the lifecycle benefits are an estimated $29.7/kW.

Benefit #4 Transmission Congestion

Description

When transmission lines are fully loaded at the same time that additional electricity is needed, the transmission system is said to be congested. In New York, congestion is a growing challenge that is being addressed, in part, using congestion charges.

Congestion charges are added to energy (LBMP) prices. In simplest terms, congestion charges reflect the energy price difference between:

a) locations with additional generation capacity but no way to move electricity to locations that need it, due to transmission congestion

and

b) locations that cannot receive more electricity from "outside" sources due to transmission congestion

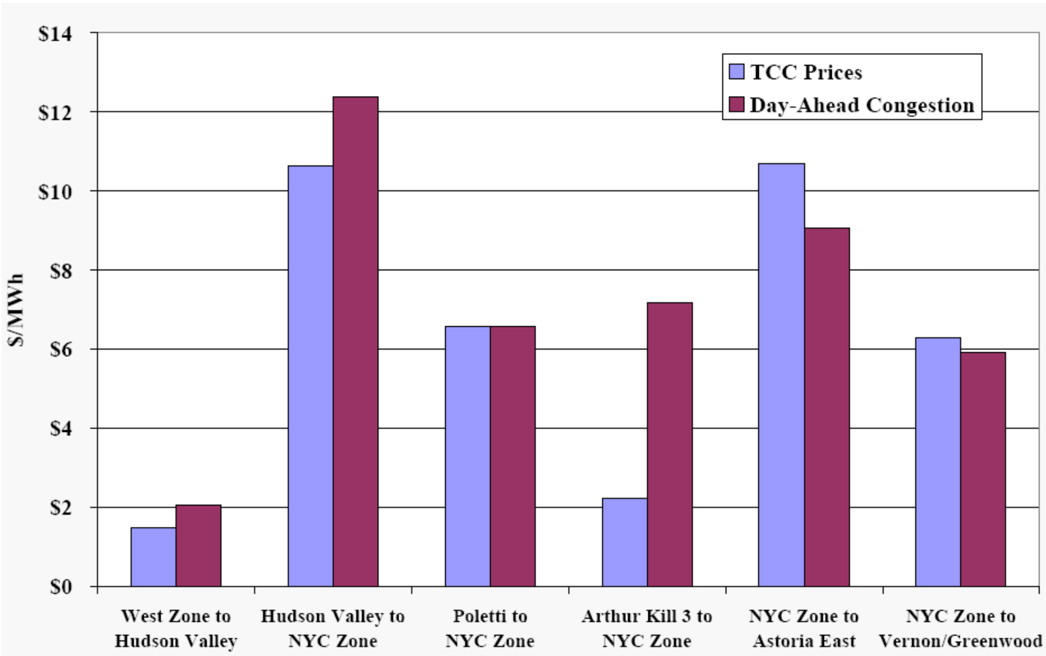
As part of New York's program to encourage an effective market for congestion relief, New York also uses transmission congestion contracts (TCCs) that reimburse holders when there is congestion. TCCs provide a way for energy buyers to manage risk associated with uncertain congestion charges. Another element of the congestion relief market program involves "non-firm" transmission service that allows users to transmit only when there is no congestion.

In NYC, congestion is an especially compelling challenge because a significant portion of electric energy must be transmitted into the city. Congestion is at its worst when NYC needs a lot of electricity from outside of the city. Storage reduces congestion charges to the extent that the storage is charged with either a) electricity generated in-city and/or b) electricity that is transmitted when there is little or no congestion.

Please see Appendix F for more details.

Approach and Assumptions

The single-year benefit for reduced congestion is established using market based price signals as indicated by a) the congestion component of LBMP and b) TCCs. Those price signals (for 2005) are summarized for parts of New York in Figure 10.



Source: Potomac Economics, April 2006. Reference [19]

Figure 10. TCC and Day-ahead Congestion Cost/Price, 2005

Benefits

Based on the values in Figure 10, the assumed avoided congestion charge is $10/MWh for energy delivered to NYC via transmission, mostly during peak demand periods when congestion charges are highest.

Applying the 7.17 PW factor, the lifecycle benefits are an estimated $71.7/kW.

Though relatively modest, that benefit may provide enough incremental value to a given value proposition, such that some storage systems (installed primarily for other purposes) become cost-effective.

Benefit #5 Transmission and Distribution Upgrade Deferral

Introduction

The single-year transmission and distribution (T&D) upgrade deferral benefit (deferral benefit) is the financial value (revenue requirement) associated with deferring a utility T&D upgrade for one year. In this report, T&D is defined as including distribution system and what is normally referred to as "subtransmission" whose Voltage is often one of the following: 69 kV, 115 kV, or 138 kV.

Specifically, to the extent that storage can be used in a way that allows a utility to defer a T&D upgrade, the *single year* benefit (from storage) is the cost that would have been incurred to own the T&D upgrade for one year.

(This concept presumes that storage used can provide "utility" that is roughly equivalent to that provided by the upgrade – when serving load on the margin. As an illustration, consider storage that is not reliable, which cannot provide "equal utility" when compared to very reliable utility upgrades.)

In general terms, locations for which distributed modular resources (including storage) are best suited for T&D deferral are those characterized by:

- infrequent and "peaky" maximum load days (i.e., peak load occurs only during a few hours in a day)
- slow load growth
- transmission or distribution upgrades required are "lumpy" (i.e., for one or a few years a small amount of storage can defer a relatively large investment; call it "storage modularity leveraging")
- high transmission access charges (that can be avoided with distributed resources)

Approach and Assumptions

The total deferral benefit (dollars of revenue requirement) for one year is calculated by multiplying the utility fixed charge rate for T&D times the total installed cost for the upgrade to be deferred.

The average distribution capacity-related cost for serving new load is estimated to be $450/kW. It is likely that most distribution upgrades cost less or even much less than this amount. A few expensive projects will cost more.

For this report, a value of $400/kW (not $450) is assumed, given this premise: because of the small scale and temporary nature of a storage-for-deferral project the transaction, engineering, and labor cost per kW-year are relatively high and decrease the net benefit that actually accrues to ratepayers.

The resulting deferral benefit per kW of storage is calculated as follows. Consider a distribution node to be upgraded to serve growing load. The upgrade will add 3 MW of capacity to the existing 9 MW, so the node will have the capacity needed to serve 12 MW of load. The 3 MW added is an increase of 33% (upgrade factor of .33).

During the next peak demand season, load is expected to exceed the existing distribution equipment's rating by 2% (2% * 9 MW existing = 180 kW. Engineers add a contingency and then specify a 250 kW storage system to defer the upgrade for one year.

The cost to add 3 MW (3,000 kW) is about $400 per kilowatt of capacity *added*, for a total cost of $1.2 Million. Using the fixed charge rate for T&D (of .1395) the annual revenue requirement is $1.2 Million * .1395 = approximately $167,000/year, or $55.8/kW-year.

For details please see Appendix P.

Single Year Benefit

To calculate the single year benefit from storage (used to defer the upgrade), divide the storage nameplate power rating into the annual deferral value. $167,000 deferral value ÷ 250 kW storage power rating = $668/kW of storage for one year.

Note that value, though realistic, is derived based on assumptions whose values can vary significantly, especially the .33 T&D upgrade factor, the T&D cost, and the storage system size.

Consider the latter criterion, storage system size, which affects the magnitude of the benefit significantly. Based on the example above, if the storage system needed must have a power rating that is 3% of T&D existing capacity (before upgrade), rather than the 2% assumed above, then the T&D deferral benefit is $167,000 deferral value ÷ 375 kW of storage = $445/kW of storage, one third less than the benefit if the storage power rating is only 2% of existing T&D capacity.

The T&D deferral benefit values described above do not include overheads for a variety of costs associated with using storage, possibly including engineering/design, procurement, set-up, administrative, permitting, etc.

Based on the foregoing, the generic value for the single year T&D deferral benefit is $500/kW of storage.

Multi-Year Deferrals

The evaluation described above involves use of storage capacity added in a specific year to defer an upgrade for *that* year. If storage will be used for a subsequent year of deferral, then the same evaluation described above is required for each subsequent year to determine a) how much additional storage is needed to serve load growth and b) whether the next year of deferral is cost-effective on the margin. (Please see Appendix P for an example calculation.)

Because the amount of storage required roughly doubles each year, though the annual benefit remains constant, it is safe to assume that in most or almost all cases, at some point in time, the T&D upgrade will be more cost-effective than adding modular resources. When that occurs, storage may remain in place to serve other applications (such as buy low - sell high or to provide reliability), or if it is transportable, it could be moved to another site to provide additional T&D deferral benefits, as summarized below.

A generic multi-year benefit of $1,200/kW is estimated assuming that the storage can be used for deferral at two or three locations (see the next section that addresses transportability) for one or two years at each over its ten year life.

Storage Redeployment and Transportability

One way that a given storage plant could provide multiple years of distribution capacity upgrade deferral benefit (and other benefits that are localized) involves moving the storage from one T&D hot spot to another. Transportable storage could also be used to address different winter and summer hot spots in the same year. This, of course, requires that the storage system can be disconnected, moved, and reconnected with modest effort and cost.

Even if a storage system is moved and re-used *once* during the life of the storage plant, the effect on storage's cost effectiveness can be dramatic.

Consider the example scenario illustrated in Figure 11. Transportable storage provides a somewhat modest single year deferral benefit of $250/kW of storage ($Year 1) in each of five years, and it provides $75/kW of power quality and reliability related benefits ($Year 1) in the other five years, during a ten year useful life.

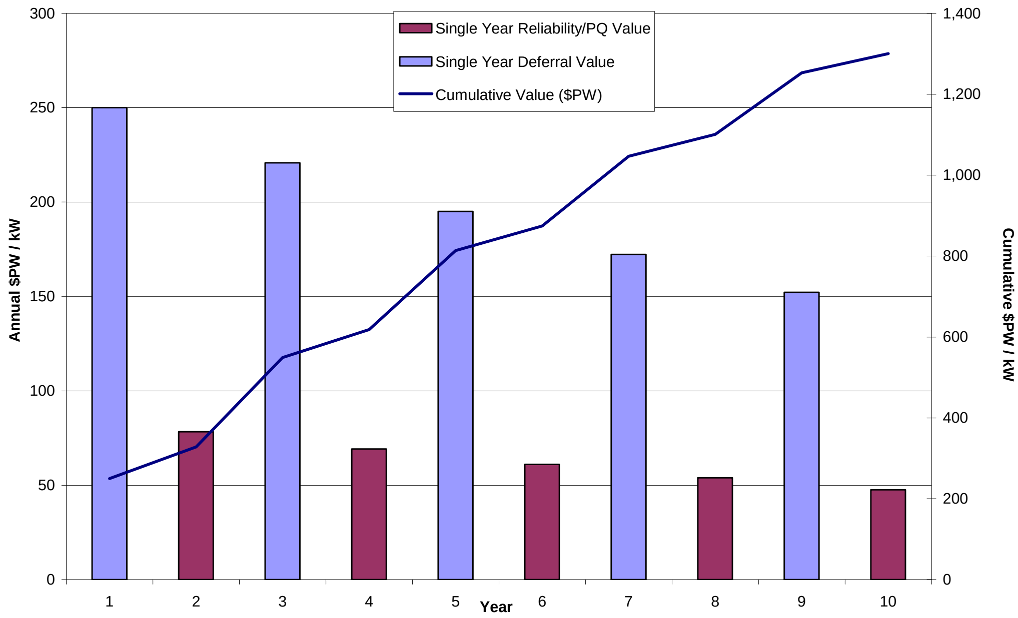


Figure 11. Value Proposition for Transportable Storage

From the figure above, the present worth of the annual amounts is about $1,300/kW of storage.

<u>Benefit #6 Operating Reserve</u>

Introduction

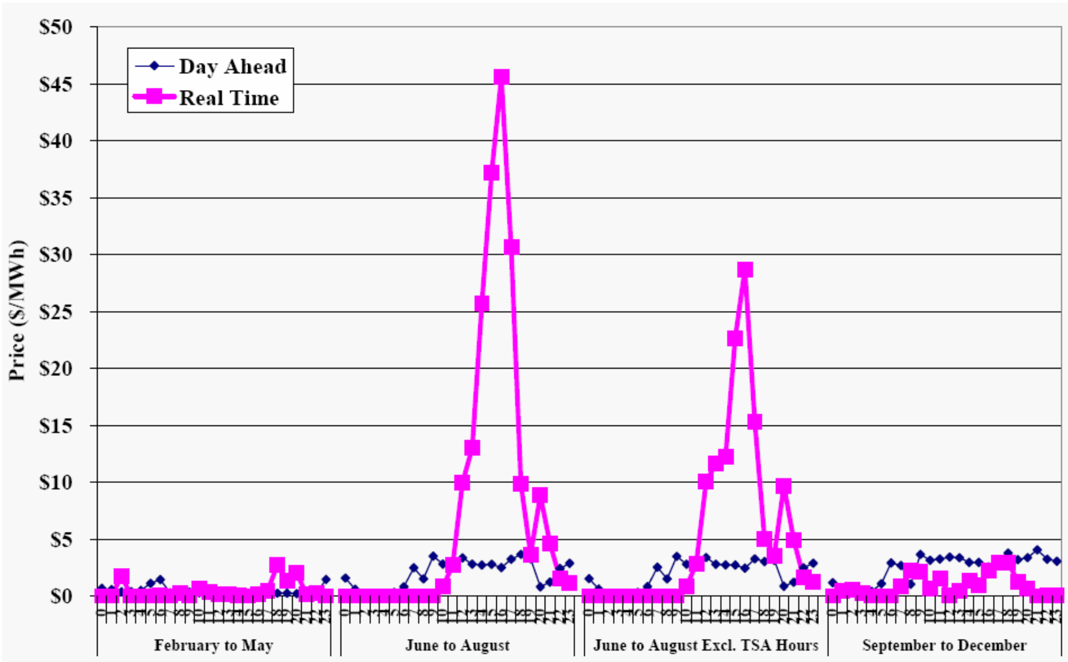
The operating reserve (ancillary) service provides backup generation capacity for the grid. Reserves are used after a major area-wide or region-wide power system disruption, especially loss of one or more major generation or transmission facility.

The NYISO offers this service to transmission owner/operators who may buy the service from the NYISO or may provide their own operating reserves.

Power from operating reserve resources must be available to the NYISO within 30 minutes, and two-thirds of that capacity must be available within 10 minutes.

Approach and Assumptions

Figure 12, below, gives a general indication of reserve pricing at the Central/Western New York interface. It shows the variation among times of year and time-of-day.



Source: Potomac Economics, April 2006

Figure 12. Hour-of-day Reserve Prices, Eastern New York in 2005

Based on values in the figure above, the value assumed for reserves is $2/MWh during times when storage used for other, more valuable applications is likely to be available to provide reserves.

Benefit

Storage can provide as little as 10 minutes of very rapid response reserve and as much as one hour of longer term reserves for 3,000 hours per year during “mid-peak” periods. 3,000 hours per year x $2/MWh = $6/kW-year.

Based on the price (LBMP) duration curve shown in Figure 7, energy for charging costs an average of $50/MWh and the value of energy during the 3,000 mid-peak hours is assumed to be about $100/MWh, for a differential of $50/MWh. Assuming storage efficiency of 80%, the remaining benefit is about $40/MWh. Most modular storage technologies have a non-energy variable operating cost that is at least that much (4¢/kWh). Nonetheless, for the purposes of this study, non-energy variable operating cost for more mature storage is assumed to be $30/MWh, leaving $10/MWh of net benefit. For 3,000 hours per year, that is a total of $30/kW per year for the energy and $36/kW-year when adding the reserve capacity payments.

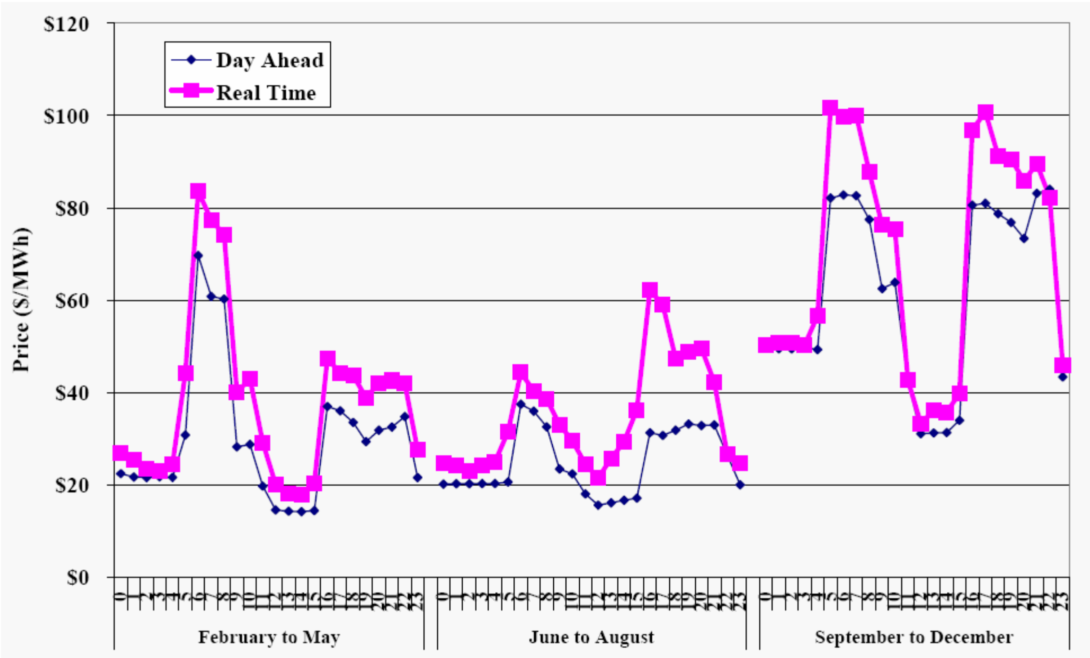
Benefit #7 Regulation and Frequency Response

Introduction

Storage used for this application provides "up regulation" and "down regulation" to offset short duration variations of electric demand and supply. Normally, this ancillary service is provided using large generation facilities whose normal output is "held back," so it can provide regulation. In most cases the generation has a much slower response rate than most forms of storage.

Approach and Assumptions

For this evaluation, hourly regulation prices from 2005 were used to estimate benefits from storage. A helpful breakdown of prices for the year 2005 is shown in Figure 13.



Source: Potomac Economics, April 2006

Figure 13. Hour-of-day Regulation Prices, New York in 2005

Benefit

Figure 14 shows the estimated regulation benefit (in units of MW provided per hour of operation) versus variable cost. Variable cost includes cost for maintenance and for energy losses.

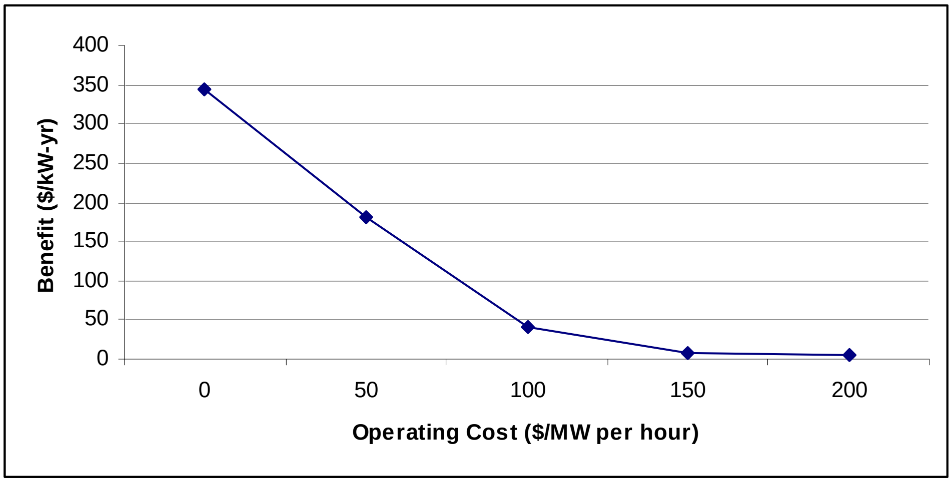


Figure 14. Regulation Benefit Versus Operating Cost

From the chart, for a reasonable variable cost of about $50/MWh, the regulation benefit is about $180/kW. That is for a unit providing regulation during every hour in the year. Given that, and a preference for making conservative estimates, the annual net benefit is about $150/kW.

Benefit #8 Transmission Support

Introduction

Energy storage that is well suited to providing very rapid, very high power output for several seconds could enhance performance of the T&D system. Important possible effects are: a) improved system stability and security, and b) improved system throughput.

For a 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)

Approach and Assumptions

The financial benefit values, listed below in Table 10, are estimated based on related research by the Electric Power Research Institute. [1] [2] That research addressed superconducting magnetic energy storage (SMES) used for T&D support needs in Southern California, during hot summer conditions, when the need and benefit are highest. The estimates are based on conservative assumptions. [2] [4]

Benefits for T&D support are gross benefits. When evaluating the merits of using energy storage for transmission support, the upper bound (of the benefit) is actually the cost for the standard utility solution, if one exists. For example, if static VAR compensators and/or capacitors would be the solution then energy storage would offset the need (and cost) for those.

Benefit

Based on these values (derived from references 1, 2, and 6), the standard assumption value for lifecycle benefit from transmission support benefit is $169/kW.

Table 10. T&D Support Financial Benefits — Standard Assumption Values

Benefit Type	Annual Benefit ($/kW-year)	Lifecycle Benefit ($PV/kW) #
Transmission Enhancement	13	96
Voltage Control ($ capital*)	n/a	25
SSR Damping ($ capital*)	n/a	14
Underfrequency load-shedding (per occurrence)	11	34**
	Total	169

Note: all value are for Southern California, assuming hot summer conditions, circumstances for which benefits are highest.

*The benefit is the cost of the most likely alternative (e.g., capacitors), that would have been incurred, if storage was not deployed.

**$11/kW, per occurrence. Assume three occurrences over the (ten year) life of the unit. This value has not been adjusted to account for time value of money.

#Based on a PV Factor of 7.17 and a ten year life.

Benefit #9 Improved Reliability

Introduction

Benefits from storage used for improved electric service reliability accrue because financial losses associated with power outages are reduced or avoided.

This benefit is end-user-specific and varies by as much as three orders of magnitude. So, any specific estimate of this benefit is, at best, an indicator.

To narrow the range of values for the benefit, it is assumed that it only applies to commercial and industrial (C&I) accounts for which power outages cause moderate to significant losses.

For this report, two possible approaches for estimating the reliability benefit are presented. Though values used are generic, they provide a reasonable general indication of the value. To the extent that better information is available for a specific circumstance, a more precise estimate can and should be made.

Benefit estimates below are gross values. The benefit accrues if costs associated with outages can be avoided by using storage, but, depending on circumstances, when considering storage for improved reliability, the “benefit” may be limited by the cost for the lowest cost substitute, if one exists. For example, if “low” cost stand-alone UPSs could serve critical loads and/or if emergency backup generators could be used to address outages, then energy storage systems might offset the need (and cost) for those rather than providing the gross benefit.

Improved Reliability Benefit – Value-of-Service Approach

For the value-of-service approach, the benefit associated with increased electric service reliability is estimated using two criteria: 1) annual outage hours – the number of hours per year during which outages occur, and 2) the value of “unserved energy” or value-of-service (VOS) units are $/kWh.

Consistent with the prevailing reliability benchmark for the electric supply and transmission system of one day of supply outages in ten years, on an annual basis there is 0.1 day per year (2.4 hours) of electric supply related outage.

Of course, electric supply disruptions do not occur every year, so that value is somewhat misleading. Many, perhaps most, outages originate at the distribution level, in part because the distribution system co-exists a) with other infrastructures. and b) where many unrelated activities occur. Given that consideration, the authors believe that the annual value of 2.5 hours (of electric service interruption) is a reasonable assumption, considering the likelihood of distribution-based interruptions.

A VOS of $20/kWh is assumed as a general indication of the value that might be ascribed to avoided outages by commercial entities that have somewhat high "value of unserved energy." [8]

To calculate the annual reliability benefit the number of annual outage hours is multiplied by the VOS:

$20/kWh * 2.5 hours per year
= $50/kW-year.

To calculate lifecycle benefits over ten years, the annual reliability benefit of $50/kW-year is multiplied by the PW factor of 7.17. Lifecycle benefits are:

$50/kW-year * 7.17
= $359/kW

Improved Reliability Benefit – The "Per Event" Approach

A second method for estimating benefits for improved reliability involves estimating financial losses associated with outage "events" that a) last for one minute or more and b) cause important or critical electric loads to go off-line.[5] Furthermore, outage events included in the evaluation are those whose effects can be avoided if storage is used.

Based on a survey of existing research and known data related to electric service reliability, a representative value for the number of annual reliability events is five and a generic cost is assumed to be $10 per reliability event for each kW of end-user peak load.[5] [6] So, storage that allows an electricity end-user to avoid five electric reliability events yields an annual value of $50/kW-year (5 events * $10/kW per event).

Multiplying by the PW factor of 7.17 yields a lifecycle benefit of $359/kW, the same as the value of service approach.

For additional information about financial considerations related to utility service reliability, readers are encouraged to refer to a report produced by Lawrence Berkeley National Laboratory entitled: *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*. [16]

Benefit #10 Improved Power Quality

Description

The benefit for improved power quality (PQ) is end-user-type-specific and often location-specific, so generalizations can only be viewed as an indication of the benefit. Also note that this benefit is quite similar to that for improving electric service reliability. The distinction is that benefits for improving reliability accrue when/if storage reduces costly effects from longer term service *interruptions* (lasting minutes to hours), whereas benefits for improved PQ accrue because effects from poor PQ are ameliorated by using storage. Poor PQ may occur infrequently, frequently, or on an ongoing basis.

Sources and types of poor power quality are well documented by others, so details are not covered in this report, though they are summarized in Section 2 in the subsection describing the power quality (PQ) application. [12] [13] [14] Common forms of poor power quality include voltage spikes and sags, undervoltage conditions, and harmonics.

Approach and Assumptions

The improved PQ benefit is assumed to apply to commercial and industrial (C&I) electricity end-users that expect to experience poor power quality. Furthermore, this benefit accrues to entities for which poor power quality causes moderate to significant financial losses. Loads of interest are those that will go off-line and/or those that are damaged if subjected to poor power quality *and* that would be protected if energy storage is used.

As an upper bound, the magnitude of the PQ benefit (avoided financial loss) that is ascribed to energy storage cannot exceed the cost to add the "conventional" solution. For example: if the annual PQ benefit associated with a facility-wide energy storage system is $100/kW-year and basic under-desk uninterruptible power supplies (UPSs) costing $30/kW-year would solve the same problem, then the maximum benefit that could be ascribed to the energy storage, for improved PQ, is $30/kW-year.

Estimating Reduced PQ-related Financial Losses

A simple estimate of PQ-related benefits can be made using expected financial losses due to individual PQ events that cause electric loads to go off-line. [5] PQ events considered are those whose effects can be avoided if storage is used.

Based on a survey of existing research and known data related to PQ, a generic value of $5/event for each kW of end-user peak load is the standard assumption value for this document. Based on that same information, the generic annual number of events assumed is 20. [5] [6]

So, storage used by electricity end-users with high value loads allows those end-users to avoid 20 power quality events per year, each worth $5 per kW of load affected, for an annual benefit of $100/kW-year.

Multiplying that value by the PW factor of 7.17 yields an estimated lifecycle benefit of $717/kW.

For additional coverage of this topic, please refer to a report developed by Lawrence Berkeley National Laboratory entitled: *Evaluating the Cost of Power Interruptions and Power Quality to U.S. Electricity Consumers*. [16]

Benefit #11 Electric Service Bill Reduction: Demand Charges

Description

To reduce the electric utility bill using storage, the storage is charged at night when demand charges and/or energy price is low, and then the storage is discharged during the day when demand charges and /or energy price is high.

Typically, demand charges apply during afternoon and evening hours of the day, during late spring to late autumn. There may be two or more demand charge levels that apply during different parts of the day or year.

It is important to note that demand charges are applied rigorously, on a monthly basis (and sometimes on an annual basis), so storage must be reliable for this application. If storage (or any other demand management option) fails to reduce demand on the grid when demand charges apply, then demand charges are assessed for the entire month.

This benefit is assumed to apply to commercial and industrial (C&I) electricity end-users that qualify for electric utility tariffs that include demand charges. The Con Edison SC9 tariff is used; it applies to most C&I load in NYC.

For more details, please see Appendix P.

Approach and Assumptions

Figure 15, below, shows diurnal demand (on the grid) with and without storage used to reduce demand charges, for a C&I facility with electric demand that peaks during the afternoon and drops starting in mid evening.

The gray area plot indicates the load without storage. The bar plots indicate the effect of storage when it serves all facility load during the six hours during which demand charges apply. (Note that the storage actually discharged at “full load” for about 5.7 hours. If the storage discharge duration is the full six hours, then there will be about .3 hours for reliability and PQ applications.) Also shown in the figure are storage charges for about 7.4 hours/night. Charging time in excess of discharge time is necessary to make up for storage energy losses.

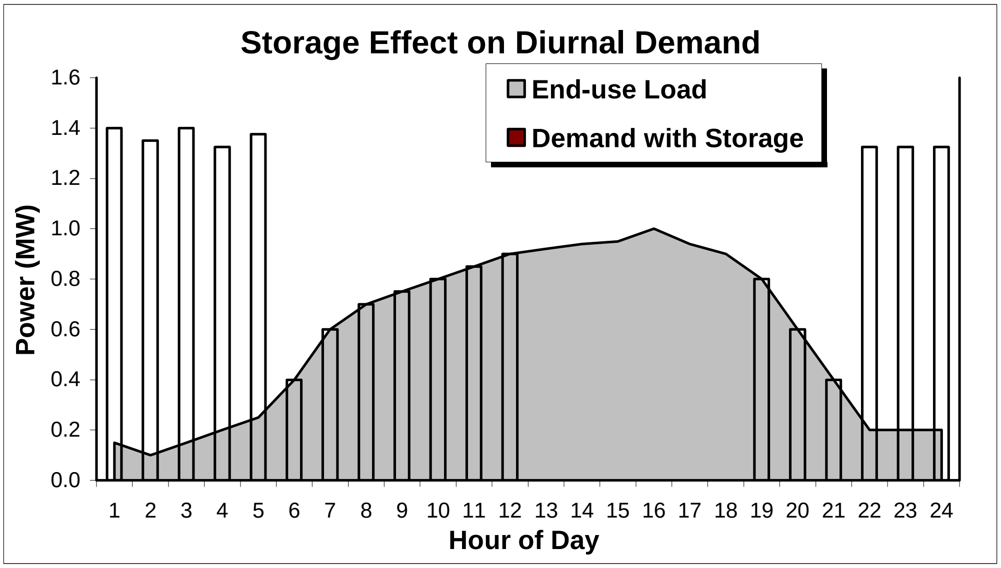


Figure 15. Demand with Storage Used to Reduce Electricity Bill

Benefit

Note: those benefits do not account for variable maintenance costs incurred as the storage plant is used (including overhauls and subsystem replacement, as applicable). Those are included in the estimate of the total lifecycle cost.

Table 11. Bill Reduction as Function of Variable Operating Cost

Storage VOC*		
¢/kWh	$/kW-year	Net Benefit
0.00	0.0	244.0
0.02	31.2	212.8
0.04	62.4	181.6
0.06	93.6	150.4

*Variable Operating Cost (not including charging energy)

Benefit #12 Electric Service Bill Reduction: Time-of-Use Energy Pricing

Introduction

At present, in Con Edison's service area, tariffs are structured in a way that is not very conducive to electricity bill reduction using time-of-use (TOU) electric energy pricing.

Consider the information in Table 12, for Con Edison's full service electric tariff P.S.C. No. 9, Service Classification No. 9. It shows demand charges associated with two rates:

- Rate II applies to end users with demand between 1.5 MW and 3 MW that are not served by an ESCO under a “retail access” arrangement, under terms of P.S.C. No. 2. (In a few special cases, Rate II applies to end-users whose demand exceeds 900 MW).

- Rate III is for end users with smaller demand that opt into the TOU rate structure.

Not shown in Table 12 are: a) price for the electric energy “commodity,” including losses, b) energy delivery charges of 0.52 ¢/kWh, c) ancillary services charge of about 0.45 ¢/kWh and d) NYPA Transmission Adjustment Charges.

Note the annual demand charge for a kilowatt of peak demand is about $180/kW-year.

Table 12. Demand and Energy Delivery Charges, P.S.C. No. 9, Customer Class 9, Rates II and III

Rate II - General - Large - Time-of-Day		
Summer (4 months)	Monthly Charge	Annual Total
Mon.-Fri., 8 AM - 6 PM	$4.73	$18.92
Mon.-Fri., 8 AM - 10 PM	$10.26	$41.04
All hours - all days	$9.79	$39.16
Total	**$14.99**	**$99.12**
Winter (8 months)	Monthly Charge	Annual Total
Mon. - Fri., 8 AM - 10 PM	$6.56	$52.48
All hours - all days	$2.73	$21.84
Total	**$9.29**	**$74.32**
	Annual Total ($/kW-year)	**$173.44**

Rate III - General - Large - Voluntary Time-of-Day		
Summer (4 months)	Monthly Charge	Annual Total
Mon.-Fri., 8 AM - 6 PM	$5.47	$21.88
Mon.-Fri., 8 AM - 10 PM	$10.24	$40.96
All hours - all days	$10.11	$40.44
Total	**$15.71**	**$103.28**
Winter (8 months)	Monthly Charge	Annual Total
Mon. - Fri., 8 AM - 10 PM	$7.55	$60.40
All hours - all days	$3.27	$26.16
Total	**$10.82**	**$86.56**
	Annual Total ($/kW-year)	**$189.84**

The commodity-related charge for electric energy in tariffs is called the Market Supply Charge (MSC). MSCs reflect day-ahead wholesale zonal energy prices. Relevant tariffs also include other modest miscellaneous charges such as a charge of about 0.45 ¢/kWh for ancillary services. Please see the P.S.C. No. 9 tariff, Rider M for Con Edison's tariffs, and Appendix S for details.

Approach and Assumptions

Based on the way TOU tariffs are structured, the most cost-effective use of storage is to target loads that tend to ramp up in the morning and to ramp down in evenings so the storage "clips" daily peak demand. (That daily load profile tends to indicate the presence of afternoon air conditioning loads.) In the example illustrated in Figure 16., 80 kW of a 1 MW peak demand is clipped.

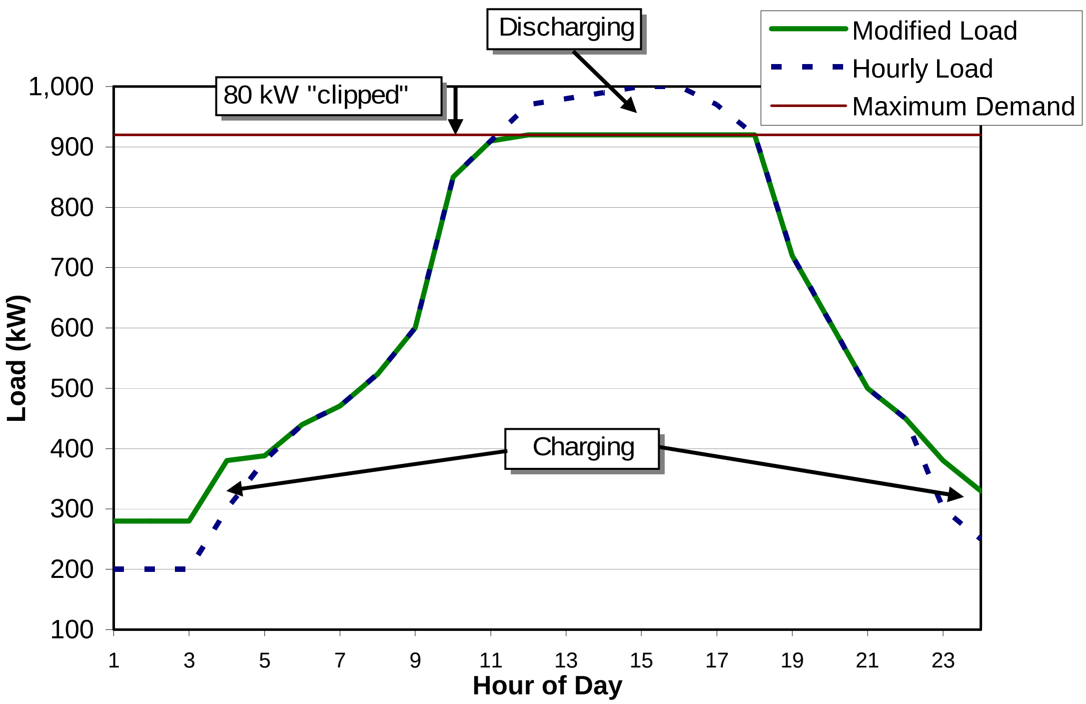


Figure 16. Peak Clipping to Reduce Time-of-use Electricity Bill

Regarding the energy commodity benefit, the total energy-related charge is assumed to range from about 7.5¢/kWh at night to about 17¢/kWh on peak during four summer months. For winter months, the on-peak energy price assumed was 10¢/kWh and off-peak price assumed was 6¢/kWh.

The value of 80 kW is somewhat arbitrary. However, as more and more kWs are clipped, the amount of energy storage (discharge duration) increases as well, so the incremental cost to clip each additional kW of peak demand increases, though the incremental benefit diminishes.

The "flatter" the demand curve for a given end-user, the lower the benefit. This is because flatter demand curves require longer discharge durations per kW clipped.

Additional details of the evaluation are presented in Appendix S.

Benefit

Based on the values in Table 12, each of the 80 kW clipped from the end user's peak demand is worth $180/year in reduced demand charges. The enhanced value of electric energy due to the time shift adds another $50/kW-year, for a total of about $230/kW-year.

Benefit #13 Increased Revenue from Renewable Energy Time-shift

Introduction

Intermittent renewable generation resources, especially wind generation, produce significant portions of electric energy when that electricity has low value – at night, on weekends, on holidays, and when there is already enough or even too much generation on-line. Energy storage could be charged using low-value energy to "time-shift" the energy to times when demand (and price) for energy (and capacity) is high.

This benefit is distinct from that for renewables capacity firming application (Application #13). The energy time-shift benefit is done primarily for energy/fuel related benefits – especially reduced effective fuel cost[2] – whereas capacity firming is used to increase renewables' "capacity value," which is related to how well renewables can offset need to equipment (i.e., generation and T&D).

Approach and Assumptions

To summarize the opportunity, off-peak production from upstate wind generation is sold, via a bilateral contract, to a load serving entity (LSE) in NYC, when energy value, congestion and losses are all low. That energy is used to charge storage located in NYC, to be discharged when the energy, capacity, and reduced loading on transmission is most valuable. Modest portions of off-peak grid energy are used to fill in when wind generation cannot fill storage.

Electricity generated by wind farms during peak periods is sold directly via the grid at the prevailing zonal price (LBMP).

Results were derived based on an analysis of wind generation undertaken by GE for NYSERDA [10]. Readers are encouraged to see details about that study and about the approach used to develop the benefit estimate in Appendix N.

[2] Wind energy that is time-shifted from off-peak times to on-peak times using storage offsets use of peaking generation with high or relatively high heat rate.

Benefit

The gross benefit includes in-city, on-peak energy and capacity, and totals about \$300/kW-year. Storage cost, including the cost for charging energy and for variable operating cost, is estimated to be \$184/kW-year. The *net* benefit is the difference, or \$116/kW-year. That is the amount that would be available to cover capital carrying charges for the storage plant.

After multiplying by the PW factor, the estimated 10 year present worth benefit is \$832/kW. Depending on location, the storage could provide other benefits.

Complete details and background regarding the benefit estimate and other, possibly important benefits that are described qualitatively are provided in Appendix N.

Benefit #14 Renewables Capacity Firming

Description

Renewable generation fueled by intermittent energy sources cannot be relied on to serve load when needed. So, without storage intermittent renewables require some amount of “firm” generation capacity to fill-in or to be ready to fill-in when power from renewable fuel is less than expected.

Storage could be charged with energy from the renewable generation and/or from the grid if cost-effective, when energy value and demand are low. That energy is used to firm up the renewable generation capacity. The firmed up capacity produces constant output (equal to the renewable generation’s rated output) during on-peak time periods.

An important premise for this application is that the storage would provide additional benefit. Depending on the location and loads served, the storage could also provide benefits for improved reliability or for improved PQ, T&D deferral, and VAR support.

Approach and Assumptions

Based on recent research and analysis, for typical circumstances, two hours of energy storage increases the average full load power output from PV systems during peak demand periods from 40% rating to nearly 100%.[17] For this report, a more conservative assumption is used: two hours of storage increases the average full load output from a PV system during Summer peak demand periods from 50% to 95%.

Of course, for any situation, the amount of storage needed varies, depending on one or more of the following: the orientation of the PV array(s), PV shading, the peak demand period (time-of-day and duration), the load shape (during the peak demand period) of the load served, and the amount of grid energy to be stored.

The PV + storage system is operated as follows: low priced off-peak grid energy is used to charge storage at night. All PV energy is sent to the grid when it is produced. During peak demand periods the stored energy “fills in” when PV-only output is not at the PV system’s nameplate output level.

As a result, the total amount of energy from the PV system increases from 2,935 kWh / kW-year to 3,586 kWh / kW-year, and the system provides 95% of its rated output as valuable on-peak capacity rather than 50%.

For this report, an additional 1/2 hour of storage is added to the PV + storage system, to provide reliability and/or PQ related benefits. Needless to say, the amount of storage needed for reliability/PQ related needs varies considerably depending on grid supply and T&D quality and the loads and end uses served. In fact, the discharge duration needed for reliability/PQ can range from seconds to hours.

Benefit

Table 13 provides a summary of net benefits from energy storage and off peak grid energy used to firm PV capacity as a system resource. It provides a breakdown of energy and capacity value from PV with storage, PV without storage, and for the incremental benefit from storage. The version shown reflects storage VOC of 4¢/kWh_{out}. All assumptions and calculations are shown in Appendix O.

Table 13. PV and PV plus Storage Capacity Firming Value and Benefit

$2006/kW-Year	Summer			Winter			Annual		
Item	Energy	Capacity	Total	Energy	Capacity	Total	Energy	Capacity	Total
PV + Storage	221.9	68.4	290.3	92.5	19.5	112.0	314.4	87.9	402.3
PV Only	202.4	36.0	238.4	87.6	10.5	98.1	290.0	46.5	336.5
Storage Incremental	19.6	32.4	52.0	4.9	9.0	13.9	24.4	41.4	65.8
				Incremental Benefit (%)			8.4%	89.0%	19.6%
					Storage VOC*				-26.1
					Net Incremental Benefit ($/kW-Year)				39.8
					(%)				11.8%

* VOC unit cost = 4.0¢/kWh out

The following table shows the effect on total incremental value from storage of storage variable operating cost (VOC).

Table 14. Capacity Firming Value as a Function of Variable Operating Cost

Storage VOC (¢/kWh out)	0¢	2¢	4¢
Incremental Value ($/kW-year)	65.8	52.8	39.8
(%)	19.6%	15.7%	11.8%

The estimated annual benefit, without regard to storage VOC, is $65.8/kW-year in the first year. That value is converted to lifecycle costs by multiplying by 7.17, for a ten year net benefit of $472/kW. If storage VOC is 4¢/kWh$_{out}$ then annual benefit drops to about $40/kW-year, or $287/kW for ten years.

Benefit #15 Reduced T&D Losses

Description

Though not associated with a separate application, use of *distributed* electricity storage could reduce T&D I^2R (“resistive”) losses and related cost; depending on 1) the storage’s location and proximity to load served, 2) source(s) of charging energy and their locations and 3) source(s) of on-peak energy purchases that are displaced when storage is discharged.

Approach and Assumptions

Generalizing the benefit related to reducing T&D losses is challenging given criteria that affect losses; especially relative location of loads and generation and time of day.

As an indication of the benefit related to reduced *energy* losses during *transmission,* consider values shown in Table 15 for the loss component of the DAM LBMP for five night and five day hours on the ten most expensive energy price days of the year in 2005.

Table 15. Marginal Cost for Energy Losses
($/MWh, Zone J LBMP Loss Component, 2005)

	Night (12am - 5am)						**Day** (12pm - 5pm)						**Difference**	
Date	**0:00**	**1:00**	**2:00**	**3:00**	**4:00**	**Totals**	**12:00**	**13:00**	**14:00**	**15:00**	**16:00**	**Totals**	**($/MW-day)**	**night/day**
9/13/2005	7.10	6.85	6.38	6.22	6.16	32.71	13.49	14.08	15.18	15.85	16.02	74.62	41.91	0.438
9/14/2005	6.44	6.08	5.53	5.43	5.39	28.87	15.90	18.43	20.29	20.96	21.30	96.88	68.01	0.298
9/26/2005	11.27	10.20	10.39	10.31	10.08	52.25	24.54	25.28	24.99	24.34	24.48	123.63	71.38	0.423
8/5/2005	12.37	11.05	9.90	9.56	9.15	52.03	25.44	25.50	25.89	25.87	25.70	128.40	76.37	0.405
9/12/2005	8.24	7.38	6.53	6.20	6.46	34.81	13.18	14.08	15.21	15.92	16.00	74.39	39.58	0.468
9/1/2205	12.11	11.44	11.17	11.02	10.86	56.60	25.02	24.41	25.60	25.29	26.11	126.43	69.83	0.448
9/27/2005	11.34	10.71	9.20	8.90	8.02	48.17	21.98	22.60	23.21	23.19	22.91	113.89	65.72	0.423
8/4/2005	11.65	9.90	9.02	8.20	7.74	46.51	23.41	24.31	24.37	24.65	24.51	121.25	74.74	0.384
9/2/2005	12.81	11.76	10.19	10.09	10.10	54.95	23.73	25.85	25.87	26.32	26.05	127.82	72.87	0.430
8/3/2005	10.20	8.57	7.69	7.48	7.44	41.38	17.95	18.64	18.80	18.58	18.99	92.96	51.58	0.445
							Average (for storage with 5 hour discharge duration)						**63.20**	**0.42**

Based on the above data, the off-peak price for energy losses *during late Summer* is about 43% of the price for losses on-peak, a difference of about $13/MWh (average of $63.2/MW-day ÷ 5 hours = $12.64/MWh).

As another point of reference, the annual average price for losses for all hours of the year (based on LBMPs for the DAM) was $9.60/MWh in 2005.

The benefit assumed for reduced transmission energy losses, per unit of energy discharged from storage, is $10/MWh.

It is reasonable to assume that charging storage located at the load at night also reduces energy losses at the subtransmission and distribution levels. Depending on locations and circumstances, losses for distribution have a magnitude that is somewhat similar to losses for transmission. A conservative estimate is that subtransmission and distribution losses that could be avoided (by charging at night and discharging when losses are high) are 50% that of transmission losses avoided, or $5/MWh.

Adding the per unit benefit assumed for transmission losses ($10/MWh discharged) to that for avoided subtransmission and distribution energy losses ($5/MWh discharged), the total is $15/MWh discharged.

As shown in Table 16, assuming the benefit for reduced T&D energy losses is $15/MWh, storage annual discharge hours ranging from 1,000 hours to 1,300 hours yield an annual benefit of $15/kW-year to $19.50/kW-year. Assuming an annual benefit of $17/kW-year, the estimated ten year benefit for reduced T&D losses is about $122/kW.

Table 16. Assumed Annual Energy-related Benefit for Avoided Energy Losses

Discharge	(days/year)	200	230	260
	(hours/year)	1,000	1,150	1,300
Annual Benefit	$/MW-year	15,000	17,250	19,500
	$/kW-year	15.0	17.3	19.5

Value of Reduced Losses: 15.0 $/MWh
Note: 5.0 hours storage discharge duration.

There are also *capacity* implications associated with reduced losses. In fact, the capacity-related benefit due to reduced losses may be more significant than the energy-related benefit, depending on location. If nothing else, the *energy* related benefit (primarily reduced fuel use) is driven by the *difference* between losses during off peak times and losses when demand is high; whereas *capacity* benefits are driven by the *total maximum* magnitude of losses because there must be enough peak capacity to make up for all losses that occur when demand peaks.

Assume, for example, transmission losses of 8% on peak. That means that there must be about 8% “extra” generation and transmission capacity to make up for the losses.

Assuming a similar level of losses at the subtransmission and distribution level (8%) *during times of maximum demand*, a capacity benefit can be estimated as follows. To generalize the value of peak capacity it is assumed to be worth a total of $200/kW-year (ICAP, transmission, and distribution). Assuming avoided losses of 8% on-peak that is $16/kW-year.

Benefit

Assuming an annual energy-related benefit for reduced T&D losses of $17/kW-year, plus an annual capacity-related benefit for reduced T&D losses of $16/kW-year; the total is $33/kW-year. After applying the PW factor of 7.17, the ten year benefit is $237/kW ($33/kW-year * 7.17).

Note that the approach above treats the energy-related benefit (for reduced losses) as a separate value, though, in practice the energy-related price associated with losses is an element of LBMPs, so the actual financial benefit accrues within the context of energy purchases made at the LBMP.

Similarly, the capacity benefit (for reduced losses) would only accrue to storage owners if the avoided cost (to the grid) is passed on to the storage owner. Nonetheless, the benefit does exist.

5. Combining Benefits

When evaluating combinations of benefits for an attractive storage value proposition, it is important to account for discontinuities between benefits. First, often there are conflicts between benefits that may make those benefits incompatible. Also, when estimating market potential, it is important to consider the degree to which the value proposition applies to the market potential associated with individual benefits.

5.a. Technical and Operational Conflicts

In many, perhaps most, circumstances two or more benefits are required for total benefits from storage to exceed cost. However, when combining benefits, thoughtful evaluation of technical and operational conflicts is required.

Technical Conflicts

Depending on which benefits are being combined, storage systems may be physically unable to provide multiple benefits.

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 buy low - sell high. Another example is storage that cannot respond very rapidly to changing line conditions. Such systems may be suitable for buy low - sell high or for bill reduction and not suitable for PQ or transmission support. Storage that does not have “very high” reliability could be used for buy low - sell high but not for supply capacity reserves.

Operational Conflicts

Operational conflicts occur when there are competing needs for the energy and/or the power that storage can deliver. Power is limited by the storage plant’s power rating, and energy is limited by the amount of energy stored. Consider an example: storage provides power in lieu of a distribution upgrade deferral. That storage system cannot provide supply reserve capacity in addition. While storage is providing T&D support, it is unlikely that it could also provide power that is stable enough to serve as supply capacity.

5.b. Market Intersections

As discussed in Section 4, care must be taken when combining benefits to account for the effect on maximum market potential. Specifically, as illustrated in Figure 17, as benefits are combined the market potential is usually reduced, dramatically for some combinations.

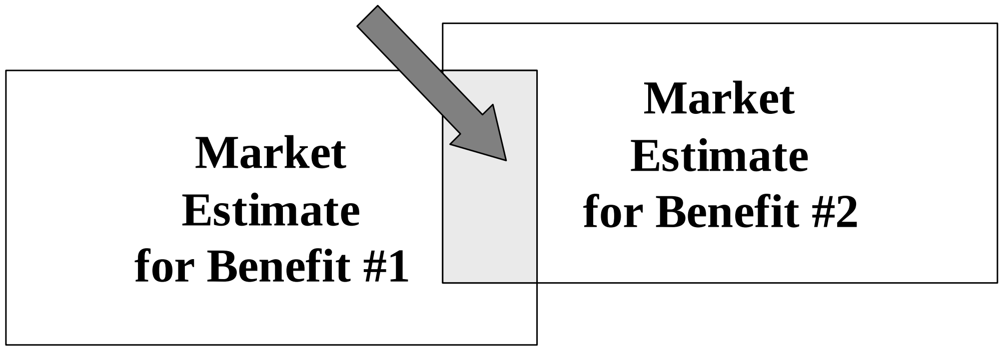


Figure 17. The Effect of Combining Benefits on Market Potential

Consider the following example: a utility customer (end-user) uses energy storage for bill reduction, improved service reliability, and to reduce cost for poor power quality. Market estimates should account for these considerations:

- Only a portion of customers that pay demand charges and that are concerned with electric reliability will derive a financial benefit from improved power quality.
- For most commercial and industrial electricity end-users that pay demand charges, increased electric reliability is not a compelling issue either.

5.c. Selected Value Propositions

What follows is a brief description of possible value propositions for electricity storage in New York comprised of two or more applications/benefits (as described in Sections 2 and 4, respectively). They are intended to be indicative of ways to combine benefits, so storage is a cost-competitive option.

5.c.1. Supply Capacity Plus Buy Low Sell High Plus T&D Deferral

A compelling value proposition for storage located in NYC is for locations (hot spots) where a T&D upgrade could be deferred and where peak demand coincides with system peak energy use and load. For such locations even a partial ICAP credit plus a time-shift benefit for energy discharged (if charged using low-priced, off peak-energy), when combined with a one year deferral benefit of several hundred dollars/kW of storage, could be a compelling value proposition.

A key premise is that energy discharged for T&D deferral in year 1 also provides incidental energy and supply capacity (ICAP) benefits, and the storage provides energy time-shift and ICAP benefits in subsequent years. Furthermore, storage used for T&D deferral often requires only a few tens of hours or as many as 200 hours of discharge per year, so, there are relatively very few hours per year when power is needed for T&D deferral, minimizing changes of conflicts with system ICAP and energy needs.

The implication is that storage used to provide T&D deferral benefits can also provide arbitrage related benefits. Even if storage does not provide T&D deferral benefits in any given year, it can still operate to do arbitrage.

5.c.2. Bill Reduction Plus Reliability

Another compelling value proposition for storage located in NYC is for businesses that could reduce electric service cost, mostly by reducing demand charges, and that would benefit from improved reliability and/or reduced losses due to power of insufficient quality.

Given the fact that many businesses, especially high value added businesses like many located in NYC, already have UPSs to ameliorate effects of power quality problems or service interruptions, it is quite conceivable that there are other *prospective* UPS users for whom the benefit is lower than the cost. For those prospective storage users, a combination of benefits may comprise a net positive value proposition.

5.c.3. Wind Generation Energy Time Shift Plus Buy Low - Sell High

Consider use of storage for a combination of two complementary applications: 1) time-shift intermittent output from wind energy *and* 2) energy buy low - sell high using grid energy. The authors speculate that energy storage used that way could increase the benefit, relative to using storage for either application separately, significantly.

Doing this allows storage to provide more benefit (per kW of rated capacity) because there are more energy-related transactions possible. And, the storage could be used for other applications (e.g., supply capacity and ancillary services).

As described in the renewable energy time shifting subsection in Section 4, storage could be decoupled from the storage plant geographically such that other, location-specific benefits may accrue as well. For example, storage used in conjunction with wind generation could provide transmission support or even, conceivably, T&D deferral benefits, depending on the storage system's location.

5.c.4. Renewables Capacity Firming Plus Reliability

Based on results for PV capacity firming, the incremental benefit for capacity firming alone may not justify the cost for 2.5 hours of storage. However, even a somewhat modest benefit for reliability and/or improved power quality, or even an environmental externality credit, could make the investment a cost-effective one.

5.c.5. Combined Heat and Power Plus Electricity Storage

One challenge for engineers that size combined heat and power (CHP) systems, especially for residential end-users, is that often there is a mismatch between times when heat is needed and times when electricity is valuable. It is conceivable that electricity storage could be used in such circumstances to store low value electricity generated when heat loads are high, for discharge when electricity price is high, often when heat loads are low.

End Notes

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